Royal Society Report on Large-Scale Electricity Storage

Supplementary Information

This is not a Royal Society publication

Slides shown at the meeting on 8/9/23 when the report was launched may be found at https://www.era.ac.uk/event/Royal-Society-largescale-energy-storage-event/ **together with notes on** two questions that were raised during the meeting:

1. **Transporting Hydrogen vs. Transporting Electricity and the Relative Locations of Supply, Storage and Demand**
   This note replaces the discussion in section 4.3 of the report and page 93 of the Supplementary Information which contain an unrealistic assumption that led to a misleadingly high estimate of the cost of transporting hydrogen (for reasons explained on page 93)
2. **Hydrogen storage in Aquifers and Depleted Gas Fields**

Stop Press - Results of analyses carried out while the Report was being printed:

- An exploratory analysis of **very large high-temperature Carnot batteries,** which is described on page 120 in SI 5.3, suggests that they could possibly play a larger role than might be inferred from section 5.2 of the Report.
- An analysis of the effect of including **correlations between demand and the weather** over the 37 years that were studied is reported on page 199. The conclusion is that in the hydrogen storage only case, correlations increase the required size of the store by some 10% (which is inside the 20% contingency that was included).
- An analysis of '**pre-emptive' demand management** in periods when very low wind speeds are forecast, which is reported on page 169 in SI 8.7, show that even modest reductions could have a significant impact on the need for storage.

Errata – Corrections to minor typographical errors in the printed version of the Report (updated 13/9/23 can be found on page 202 (if others are found, corrections will be added). They have been corrected in the on-line version.

Contents

SI 1 Introduction

1.2 Context

Fig 1.1 shows hour-by-hour demand, supply (broken down into wind and solar) and unmet (residual) demand, in two fortnights in January and July 1992, with supply equal to demand averaged over the 37 years studied. If stored surpluses are used to fill deficits, average supply has to be bigger than average demand as storage is not 100% efficient. The figure below shows the same periods at the threshold energy of average of wind and solar supply = 703.5 TWh/year at which hydrogen storage with a round-trip efficiency of 40.7% can just meet residual demand. In this case, 40.7% of the surpluses are available (after storage) to fill deficits. When above zero, the brown lines in Fig SI 1.1 show the available 40.6% of the surpluses; when below zero, it shows the deficits (at this energy the sum of the available surpluses is exactly enough to fill all deficits over 37 years). The relationship between the positive and negative portions of the brown line provides a feeling for typical intervals between stores being charged and discharged in repose to short-term changes in supply and demand.

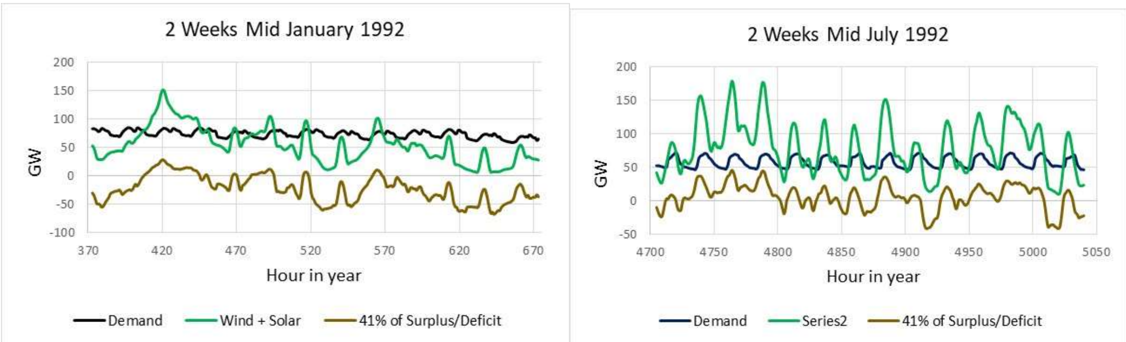

Figure SI 1.1 *Available surpluses (= actual surpluses x 0.407, the assumed round trip efficiency) and deficits at the threshold for storage to work*

Fig 1.2 shows net annual surpluses in calendar years with supply averaged over 37 years set equal to demand. Fig SI 1.2 shows the 'available surpluses' at the threshold value of average wind and solar supply, of 703.5 TWh/year, at which demand can be met by wind and solar supported by hydrogen storage with 40.7% round trip efficiency. 'Available surplus' = actual surpluses x 0.407 which is the amount that the surpluses can deliver after storage.

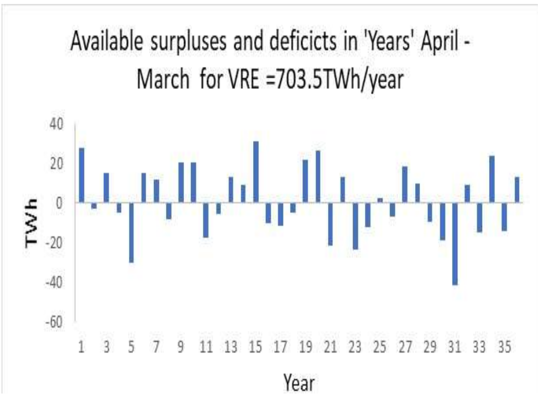

Figure SI 1.2 *Available surpluses (= actual surpluses x 0.407, the assumed round trip efficiency) and deficits at the threshold for storage to work. Averaged over all years, the available surpluses and deficits are equal at the threshold.*

To meet the large deficits seen in years 29-31 a very large storage volume is needed. However, as seen in Fig 3.1, the size of the deficit decreases very rapidly and average wind plus solar supply increases above the threshold energy of 703.5TWh/year – see SI 3.2 for further dicussion.

1.3 Storage

Box 1 does not include 'line packing' i.e. gas contained in the high-pressure tiers of the UK's transmission and distribution network, which in 2013-18 averaged 4,405 GWh (thermal – higher heating value – energy content). The amount varies, as the pressure is changed, thereby providing flexibility. The range of daily variation in this period averaged 253 GWh, with a maximum of 690 GWh. As recorded in the 2019 UK Radioactive Material Inventory (See https://www.gov.uk/government/news/2019-inventory-of-uk-radioactive-waste-published), a large amount of energy is stored in nuclear materials, but it is not available to provide power at short notice

1.4 Cost Considerations

The 'Levelised Cost of Storage (LCOS)' is defined as the cost of a unit of electrcity discharged from a storage device, accounting for all costs incurred and the energy produced throughout its lifetime[1]. The literature contains many estimates of the LCOS for different storage systems (see references[1,2] for good examples), which depend not only on the unit costs (and hence scale) and efficiencies of the system, but on assumptions about how it will be used (load factors, charging and discharging rates). LCOS is a useful measure for comparing systems called upon to do the same job, but in this report unit costs and performances are used directly to estimate the cost of carrying out functions identified by modelling.

Annex SI1 Key Question about Storage Technologies

Key Questions that are addressed in this report, albeit not in detail in all cases include:

- Is it suitable for large-scale (aggregated, central and/or distributed) storage? Are the limits on scale technical or financial?
- Is it suitable for storing for minutes, weeks, months or years? Are the constraints technical (e.g. self-discharge) and/or financial (i.e. large capital cost makes it too expensive unless used frequently)?
- How fast can the store be charged and discharged?
- What is its efficiency?
- What are the likely future costs (capital and operational; how sensitive are they to the discount rate?) for i) converting electricity to a storable form of energy, ii) transporting it and storing it, and iii) converting stored energy to electricity?
- Are there limitations on where it can be located?
- How safe is it? Can potential hazards be mitigated?
- What are its environmental impacts (e.g. because of residual greenhouse gas emissions, carbon embedded in production, or the disruption of natural habitats)?
- Will it be socially acceptable?
- How soon could it be deployed? Is there a need for more R&D and/or demonstrators? Could it benefit from existing infrastructure? Are there potential supply chain issues, or other limits on how fast it could be deployed?
- System value: what need would it fill, and what value would it provide for the whole system?
- Will/what market reforms and/or changes in regulations be needed to encourage timely deployment?

References

[1] Schmidt O, Melchior S, Hawkes A, Staffell I. 2019 Projecting the Future Levelized Cost of Electricity Storage Technologies. *Joule.* ***3****,* 81-100. (doi.10.1016)
[2] Lazard. Lazard's levelized cost of storage analysis- version 7.0. See https://www.lazard.com/media/451882/lazards-levelized-cost-of-storage-version-70-vf.pdf). BEIS

S 1 2 Electricity Demand and Supply in the Net Zero Era

2.2 Future Electricity Demand in Great Britain

Daily Profile of Electricity Demand

Demand is highest in winter and, depending on the time of day and the temperature, currently fluctuates by up to 20 GW in the winter and 10 GW in the summer. It is lower at week-ends and on national holidays. Hourly demand averaged over each quarter in the period 2012-17 in shown in SI 2.2, which also shows the variation between quarters.

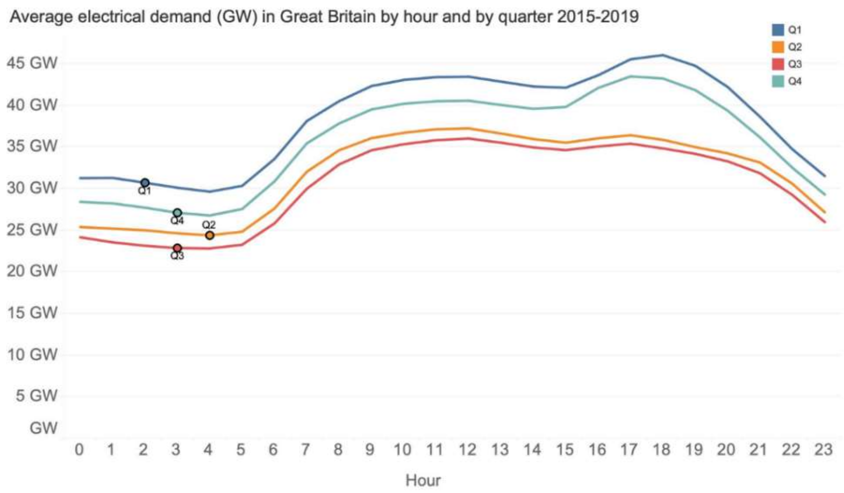

Figure SI 2.1 Profile of average daily electricity demand in each quarter in the period 2012-17[i]

2.3 Weather, Wind and Sun

Wind variations

The wind fluctuates on time scales ranging from fractions of a second to many years – as sketched in Figure SI 2.2. The most important timescales are annual, synoptic (lasting several days, extended over distances of perhaps 1000 km), diurnal, and turbulent (less than a minute). There is a gap in the energy spectrum of wind fluctuations between 1 minute and several hours, where driving forces are largely absent. Measurements that average over this spectral gap supress turbulent fluctuations, but preserve the variations with longer periods that are significant for wind power[1].

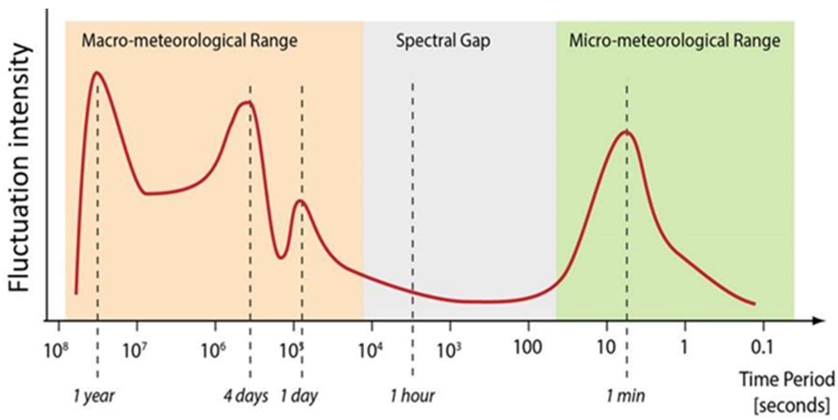

Figure SI 2.2 Fluctuation spectrum of wind at a typical site (Courtesy of Green Rhino Energy Ltd)

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[i] Plot courtesy of I A G Wilson based on DUKES data

On shore: a 2007 paper by Sinden[2] contains the plot in Fig SI 2.3 of capacity factors, averaged over 34 years, of onshore UK wind farms in different seasons as a function of the time of day.

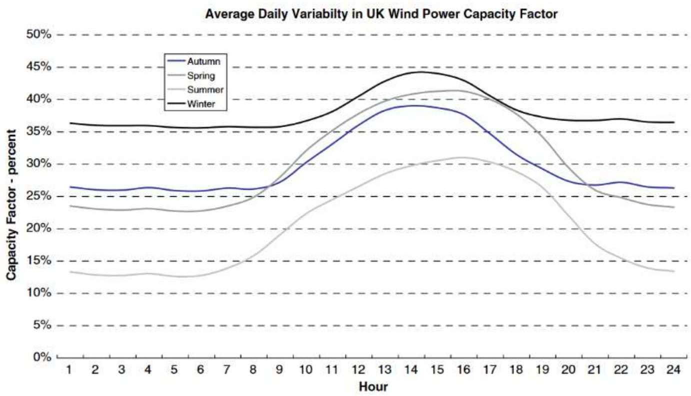


Figure SI 2.3: Average hourly wind power availability by season (averaged over 34 years of wind speed data)

Offshore: Fig SI 2.4, produced by Potisomporn and Vogel[3], shows diurnal variation in different seasons of the average capacity factors in 2011-17 of 32 operating UK offshore wind farms. At these sites, the wind speed was less than 4 m/sec (the typical turbine cut-off speed) 7% of the time, but only above 25 m/sec (the typical upper cut-off) 0.3% of the time. Low speed periods are more probable during the day (47% occur between 8 am and 4 pm, 5.4% between 4pm and 5pm, but only 19.5% between 8 pm and 4 am).

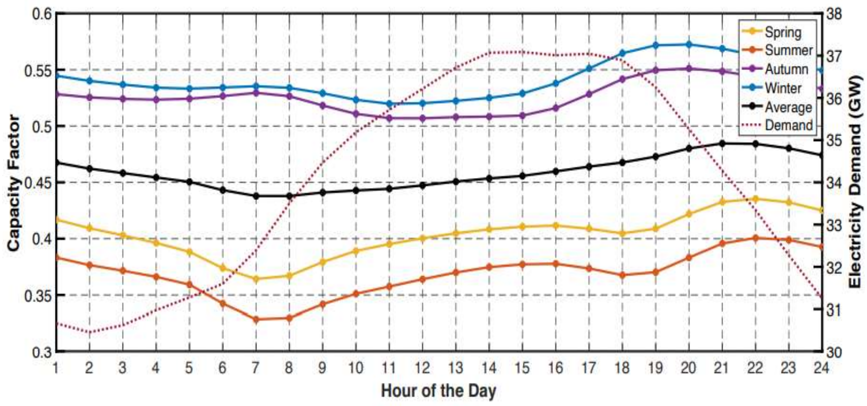


Figure SI 2.4 Diurnal variation in different seasons of the average capacity factors in 2011-17 of 32 operating UK offshore wind farms

Extreme Weather Events and Periods of Low Supply

Figures SI 2.5 A and B show wind plus solar output (mixed 80/20), obtained from the Ninja Renewables model (which is based on real weather data), in each month of the 37 years that were studied as a percentage of the 37-year average for that month. From Fig SI 2.5 A, which is plotted by calendar year, it is seen that there are periods of low supply in the summer. The most extreme cases, which occur in the winter and span calendar years, are most early spotted in Fig SI 2.5 B which shows the same data plotted in years April to March. Note the extreme cases of December 2008-09, 2209-10 and 2010-11, which run on to April and even beyond. The effect that these 'bad' periods have on storage is clearly seen Figs 1.2 and 3.2.

	Month											
Year	1	2	3	4	5	6	7	8	9	10	11	12
1980	74%	71%	89%	103%	100%	94%	115%	106%	99%	108%	133%	130%
1981	97%	93%	102%	101%	93%	125%	91%	81%	107%	105%	116%	81%
1982	82%	99%	105%	104%	89%	86%	96%	113%	105%	90%	116%	101%
1983	141%	87%	109%	93%	93%	101%	83%	82%	128%	125%	75%	115%
1984	115%	96%	78%	90%	90%	105%	95%	82%	99%	112%	102%	92%
1985	87%	76%	81%	115%	95%	95%	109%	133%	95%	73%	104%	101%
1986	125%	95%	103%	99%	129%	116%	96%	108%	85%	103%	125%	127%
1987	77%	73%	106%	99%	104%	83%	102%	94%	103%	93%	83%	88%
1988	97%	133%	99%	86%	97%	90%	127%	115%	115%	93%	86%	105%
1989	96%	129%	114%	99%	97%	96%	104%	108%	92%	109%	83%	73%
1990	123%	149%	128%	107%	78%	101%	105%	101%	101%	119%	83%	112%
1991	89%	81%	84%	128%	94%	109%	110%	94%	96%	96%	105%	84%
1992	70%	100%	123%	113%	112%	94%	98%	127%	104%	90%	125%	77%
1993	123%	85%	102%	94%	112%	86%	110%	97%	97%	81%	81%	115%
1994	116%	86%	144%	115%	97%	115%	86%	102%	107%	92%	83%	121%
1995	120%	118%	125%	105%	89%	114%	106%	95%	98%	101%	94%	76%
1996	106%	105%	92%	91%	112%	103%	94%	101%	105%	109%	107%	85%
1997	55%	133%	94%	99%	92%	112%	90%	86%	92%	86%	94%	107%
1998	98%	119%	98%	104%	95%	113%	110%	112%	99%	133%	86%	108%
1999	101%	114%	88%	97%	106%	97%	104%	87%	99%	111%	110%	122%
2000	105%	128%	102%	95%	98%	103%	85%	77%	96%	110%	108%	108%
2001	74%	90%	90%	110%	92%	107%	100%	91%	122%	114%	98%	87%
2002	100%	124%	95%	106%	114%	114%	88%	77%	75%	103%	89%	88%
2003	106%	88%	82%	103%	103%	100%	105%	86%	73%	101%	95%	92%
2004	102%	105%	95%	92%	78%	107%	89%	109%	127%	104%	86%	92%
2005	126%	98%	100%	102%	110%	94%	96%	103%	98%	98%	107%	86%
2006	76%	97%	106%	104%	110%	92%	92%	102%	94%	99%	129%	101%
2007	123%	89%	109%	92%	97%	96%	109%	104%	113%	65%	112%	94%
2008	121%	100%	127%	97%	102%	103%	112%	110%	93%	107%	106%	80%
2009	93%	72%	98%	89%	116%	84%	114%	110%	100%	92%	109%	85%
2010	82%	72%	91%	86%	78%	89%	97%	104%	109%	101%	97%	71%
2011	82%	95%	75%	97%	116%	98%	105%	90%	114%	112%	96%	132%
2012	101%	96%	75%	96%	93%	117%	93%	95%	114%	85%	96%	105%
2013	82%	85%	102%	110%	110%	99%	86%	93%	96%	117%	91%	125%
2014	107%	123%	100%	98%	88%	74%	97%	114%	65%	106%	79%	118%
2015	113%	92%	107%	84%	113%	107%	108%	105%	91%	74%	122%	133%
2016	112%	107%	83%	97%	109%	83%	94%	102%	94%	82%	87%	83%

Fig SI 2.5 A. Wind and solar output as a percentage of the average for that month, in calendar years.

	Month											
Year	4	5	6	7	8	9	10	11	12	1	2	3
1980	103%	100%	94%	115%	106%	99%	108%	133%	130%	97%	93%	102%
1981	101%	93%	125%	91%	81%	107%	105%	116%	81%	82%	99%	105%
1982	104%	89%	86%	96%	113%	105%	90%	116%	101%	141%	87%	109%
1983	93%	93%	101%	83%	82%	128%	125%	75%	115%	115%	96%	78%
1984	90%	90%	105%	95%	82%	99%	112%	102%	92%	87%	76%	81%
1985	115%	95%	95%	109%	133%	95%	73%	104%	101%	125%	95%	103%
1986	99%	129%	116%	96%	108%	85%	103%	125%	127%	77%	73%	106%
1987	99%	104%	83%	102%	94%	103%	93%	83%	88%	97%	133%	99%
1988	86%	97%	90%	127%	115%	115%	93%	86%	105%	96%	129%	114%
1989	99%	97%	96%	104%	108%	92%	109%	83%	73%	123%	149%	128%
1990	107%	78%	101%	105%	101%	101%	119%	83%	112%	89%	81%	84%
1991	128%	94%	109%	110%	94%	96%	96%	105%	84%	70%	100%	123%
1992	113%	112%	94%	98%	127%	104%	90%	125%	77%	123%	85%	102%
1993	94%	112%	86%	110%	97%	97%	81%	81%	115%	116%	86%	144%
1994	115%	97%	115%	86%	102%	107%	92%	83%	121%	120%	118%	125%
1995	105%	89%	114%	106%	95%	98%	101%	94%	76%	106%	105%	92%
1996	91%	112%	103%	94%	101%	105%	109%	107%	85%	55%	133%	94%
1997	99%	92%	112%	90%	86%	92%	86%	94%	107%	98%	119%	98%
1998	104%	95%	113%	110%	112%	99%	133%	86%	108%	101%	114%	88%
1999	97%	106%	97%	104%	87%	99%	111%	110%	122%	105%	128%	102%
2000	95%	98%	103%	85%	77%	96%	110%	108%	108%	74%	90%	90%
2001	110%	92%	107%	100%	91%	122%	114%	98%	87%	100%	124%	95%
2002	106%	114%	114%	88%	77%	75%	103%	89%	88%	106%	88%	82%
2003	103%	103%	100%	105%	86%	73%	101%	95%	92%	102%	105%	95%
2004	92%	78%	107%	89%	109%	127%	104%	86%	92%	126%	98%	100%
2005	102%	110%	94%	96%	103%	98%	98%	107%	86%	76%	97%	106%
2006	104%	110%	92%	92%	102%	94%	99%	129%	101%	123%	89%	109%
2007	92%	97%	96%	109%	104%	113%	65%	112%	94%	121%	100%	127%
2008	97%	102%	103%	112%	110%	93%	107%	106%	80%	93%	72%	98%
2009	89%	116%	84%	114%	110%	100%	92%	109%	85%	82%	72%	91%
2010	86%	78%	89%	97%	104%	109%	101%	97%	71%	82%	95%	75%
2011	97%	116%	98%	105%	90%	114%	112%	96%	132%	101%	96%	75%
2012	96%	93%	117%	93%	95%	114%	85%	96%	105%	82%	85%	102%
2013	110%	110%	99%	86%	93%	96%	117%	91%	125%	107%	123%	100%
2014	98%	88%	74%	97%	114%	65%	106%	79%	118%	113%	92%	107%
2015	84%	113%	107%	108%	105%	91%	74%	122%	133%	112%	107%	83%
2016	97%	109%	83%	94%	102%	94%	82%	87%	83%			

Fig SI 2.5 A. Wind and solar output as a percentage of the average for that month, in years April to March.

Occasional short periods of exceptionally low supply, which can be an issue in systems with limited amounts of storage, are relatively rare. With, for example, average wind pus solar supply of 741 TWh/year, there are only 16,853 hours in 37 years (an average of 38 hours per month) with supply less than 16.9 GW = 20% of the annual average, and 4,421 hours 10/month) with supply less than 8.5 GW = 10% of the annual average. Figs SI 2.6 A and B show the hours in which supply is less than 10% and 20% of the average for that month, which varies from 77.4 GW in July to 95.1 GW in January.

Year	1	2	3	4	5	6	7	8	9	10	11	12
1980	9	27	11	3	5	14	6	25	6	12	0	0
1981	0	0	0	8	0	7	10	19	3	10	0	20
1982	7	8	2	9	14	15	0	8	7	2	5	14
1983	0	10	0	11	9	0	16	15	7	0	9	2
1984	0	20	0	0	5	20	17	24	4	0	0	27
1985	23	56	0	12	1	5	5	1	29	24	4	10
1986	0	27	2	8	0	7	22	14	11	3	0	0
1987	14	36	19	0	0	28	18	9	6	21	59	19
1988	4	0	8	8	12	13	1	12	2	5	7	0
1989	0	3	0	0	9	8	4	13	5	2	22	25
1990	0	0	7	0	8	14	8	11	9	0	20	7
1991	35	34	9	0	23	13	18	10	28	6	13	44
1992	30	11	0	5	15	0	21	3	9	11	6	0
1993	0	3	1	23	2	14	0	7	16	5	18	4
1994	5	9	0	0	5	0	23	7	4	39	11	2
1995	5	11	0	6	29	0	0	6	9	18	21	55
1996	4	12	18	13	6	10	8	2	22	2	3	41
1997	31	0	10	7	4	9	7	12	17	19	0	0
1998	0	0	2	10	12	0	3	0	9	3	26	0
1999	0	15	10	33	0	18	0	14	1	5	2	9
2000	0	6	26	4	5	30	27	31	10	4	1	22
2001	59	9	17	8	4	6	12	7	4	5	22	0
2002	2	6	0	8	1	0	0	21	6	18	20	21
2003	8	0	58	8	5	7	16	12	13	7	0	17
2004	13	27	5	24	19	12	3	20	5	5	8	6
2005	0	0	16	7	19	1	28	2	0	0	16	5
2006	26	23	0	0	12	19	16	4	15	15	0	59
2007	0	4	10	0	0	10	3	4	5	30	0	0
2008	4	44	2	0	1	13	12	2	2	3	6	22
2009	6	16	21	8	0	17	0	4	8	22	13	4
2010	3	20	17	6	11	9	3	18	10	0	0	27
2011	0	12	15	3	1	3	4	16	1	6	0	0
2012	34	0	16	4	20	24	1	12	9	24	6	0
2013	14	14	2	1	3	20	5	11	19	5	4	0
2014	9	0	7	9	12	38	5	10	22	0	24	5
2015	17	2	12	11	3	7	9	0	2	34	2	11
2016	10	7	0	1	9	12	0	4	14	14	8	6

Fig SI 2.6 A Hours in each month in which with wind + solar supply is less than 10% of the average for that month, with average supply over 37 years of 741 TWh/year (84.6 GW)

	Month											
ear	1	2	3	4	5	6	7	8	9	10	11	12
1980	45	86	46	34	17	39	14	55	23	56	0	0
1981	19	30	10	25	11	23	32	85	26	31	14	70
1982	42	33	37	25	56	59	28	38	23	44	28	51
1983	0	34	4	49	59	8	66	46	25	8	36	8
1984	14	39	48	22	51	50	73	87	41	11	15	90
1985	50	131	41	32	32	34	13	13	51	102	20	20
1986	0	41	14	47	4	30	51	67	49	31	0	5
1987	72	74	36	19	27	73	41	43	15	67	111	64
1988	29	0	46	51	41	29	22	35	17	61	24	11
1989	7	6	21	21	28	46	26	34	39	21	73	93
1990	0	6	16	9	51	56	47	37	35	0	73	45
1991	109	85	37	4	78	41	44	37	57	32	37	118
1992	95	34	0	11	25	47	55	17	35	35	20	33
1993	8	73	23	38	29	21	2	39	74	21	68	13
1994	10	36	0	9	26	26	62	26	18	78	45	11
1995	15	30	0	20	63	15	15	37	36	54	37	126
1996	35	39	61	28	25	38	45	31	60	34	40	108
1997	113	13	38	34	40	28	34	84	83	68	30	26
1998	8	0	30	26	42	4	25	20	36	9	62	20
1999	10	39	26	86	25	48	23	51	20	20	20	20
2000	18	9	65	40	35	53	82	94	32	21	9	70
2001	127	47	40	16	37	24	53	56	18	12	73	38
2002	61	9	9	41	21	3	7	86	78	55	56	56
2003	23	22	116	28	16	26	33	70	61	15	19	58
2004	28	64	32	57	79	35	41	42	26	46	42	41
2005	2	35	36	16	49	16	48	42	22	30	39	39
2006	72	66	13	21	34	81	45	21	52	45	3	152
2007	0	27	17	41	12	34	23	21	33	105	28	29
2008	9	87	21	41	11	32	28	19	37	26	38	65
2009	37	56	41	46	17	65	6	37	12	68	49	13
2010	22	55	38	43	58	40	35	42	28	8	36	114
2011	12	21	68	27	8	25	57	38	22	21	28	9
2012	50	42	76	29	81	45	28	69	13	38	22	15
2013	64	61	38	34	19	45	28	44	44	17	14	5
2014	30	8	30	32	51	82	46	43	104	12	76	19
2015	18	19	43	54	23	26	34	23	46	62	12	31
2016	37	31	16	32	37	58	27	26	43	58	30	67

Fig SI 2.6 B Hours in each month in which with wind + solar supply is less than 20% of the average for that month, with average supply over 37 years of 741 TWh/year (84.6 GW)

As discussed in section 3.3 of the Report, it is possible to forecast periods of prolonged low wind speeds. This raises the possibility of reducing demand when such periods are forecast, thereby reducing the need for storage. This possibility is explored in section 8.7 using the data for 1980-2016, assuming that demand is reduced whenever a three-month period of low wind is foreseen. Fig 2.6 C shows, for each month, the average value of available wind energy in the coming three months divided by the average for those three months. The effect of different sizes of reductions were considered in the relatively rare cases that this ratio is less than 0.8, and the more common cases that it is less than 0.85 or 0.9.

	Month											
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1980	76.5%	84.5%	93.3%	96.0%	104.4%	110.8%	111.4%	106.9%	116.4%	126.0%	120.6%	107.5%
1981	98.5%	99.5%	101.7%	111.2%	108.4%	100.2%	91.2%	98.5%	111.9%	101.2%	92.3%	86.2%
1982	93.8%	101.6%	97.3%	89.6%	85.5%	99.0%	107.4%	104.6%	105.6%	103.9%	121.7%	111.7%
1983	116.1%	98.1%	103.0%	97.3%	90.1%	80.3%	96.3%	116.7%	111.5%	106.1%	102.7%	109.8%
1984	96.5%	82.8%	78.7%	88.5%	91.5%	86.6%	86.3%	97.3%	105.9%	102.6%	93.7%	84.2%
1985	79.5%	88.7%	97.1%	104.2%	100.1%	120.7%	119.1%	99.2%	88.0%	91.3%	110.7%	107.7%
1986	109.2%	99.4%	116.4%	123.0%	121.6%	109.6%	93.2%	97.5%	104.5%	119.9%	108.8%	91.5%
1987	83.5%	91.3%	104.3%	94.3%	96.9%	92.1%	101.6%	97.0%	92.5%	87.5%	89.7%	105.6%
1988	111.0%	107.3%	92.4%	85.6%	108.3%	118.4%	129.5%	109.4%	96.6%	94.1%	95.1%	109.6%
1989	114.0%	118.7%	104.9%	94.1%	93.9%	100.9%	99.9%	103.8%	93.6%	86.9%	93.3%	116.5%
1990	137.2%	133.9%	102.8%	90.0%	87.3%	102.0%	100.3%	109.1%	101.1%	105.5%	94.0%	93.7%
1991	83.3%	96.9%	101.5%	114.9%	105.7%	106.0%	97.2%	92.6%	99.0%	95.2%	85.1%	82.7%
1992	97.3%	117.3%	122.7%	108.4%	100.5%	111.0%	117.1%	110.5%	109.1%	97.7%	109.5%	96.3%
1993	104.5%	93.0%	103.8%	97.7%	104.3%	95.4%	102.3%	88.2%	83.3%	91.4%	104.8%	107.1%
1994	118.2%	119.8%	127.0%	112.8%	97.6%	99.8%	97.7%	100.1%	93.2%	98.9%	110.0%	122.2%
1995	124.6%	120.1%	107.8%	100.9%	101.2%	103.3%	96.1%	95.2%	96.9%	88.9%	92.1%	95.1%
1996	101.0%	95.4%	98.8%	103.3%	103.2%	96.4%	98.4%	106.0%	107.6%	99.9%	79.5%	88.5%
1997	91.4%	110.0%	92.0%	101.6%	98.1%	95.7%	84.3%	83.3%	88.4%	95.2%	100.4%	107.9%
1998	105.6%	110.9%	101.1%	108.2%	110.3%	119.8%	110.6%	120.0%	108.1%	110.7%	99.2%	108.6%
1999	101.4%	100.0%	96.2%	100.7%	102.5%	93.8%	95.3%	99.9%	107.0%	114.8%	112.8%	119.0%
2000	112.1%	110.9%	98.8%	99.5%	93.6%	82.4%	81.5%	95.5%	108.1%	110.7%	96.0%	89.1%
2001	82.1%	97.0%	96.6%	104.3%	97.5%	99.9%	108.0%	113.3%	112.9%	98.8%	94.3%	103.6%
2002	107.3%	109.4%	105.8%	116.8%	111.7%	91.8%	71.9%	82.5%	88.6%	93.7%	94.6%	93.0%
2003	89.1%	85.1%	92.4%	103.1%	105.8%	94.5%	81.2%	81.5%	87.7%	94.8%	96.3%	99.0%
2004	100.4%	97.1%	85.7%	89.5%	86.9%	104.2%	113.5%	117.3%	106.2%	94.3%	102.8%	106.9%
2005	110.6%	101.4%	106.6%	104.6%	101.8%	96.6%	98.5%	98.5%	100.4%	95.7%	87.3%	84.0%
2006	90.9%	102.6%	110.2%	103.6%	96.2%	90.3%	92.4%	97.5%	107.8%	109.7%	118.2%	105.9%
2007	108.1%	93.9%	97.6%	92.3%	103.9%	105.8%	112.5%	89.2%	94.1%	88.6%	109.7%	105.0%
2008	117.9%	110.3%	113.4%	101.0%	107.2%	112.9%	108.2%	105.7%	103.5%	97.1%	92.1%	80.8%
2009	86.3%	82.6%	99.6%	93.8%	107.6%	104.6%	112.1%	100.2%	100.3%	95.0%	91.1%	78.8%
2010	79.7%	78.5%	78.0%	73.2%	79.4%	94.4%	106.7%	106.3%	102.8%	88.0%	81.5%	81.2%
2011	81.1%	84.7%	90.9%	103.9%	110.0%	97.4%	105.7%	107.9%	107.8%	114.3%	109.6%	109.7%
2012	87.5%	85.5%	83.0%	105.3%	103.5%	106.0%	103.5%	97.8%	97.8%	95.3%	94.1%	89.9%
2013	88.1%	97.5%	109.6%	109.4%	96.8%	86.1%	86.3%	103.9%	102.3%	112.7%	108.8%	120.2%
2014	111.2%	108.8%	94.3%	81.0%	78.1%	90.5%	85.9%	93.3%	81.3%	101.6%	103.8%	108.2%
2015	104.7%	92.2%	101.0%	99.8%	114.3%	110.5%	101.6%	85.3%	94.0%	110.8%	124.2%	118.4%
2016	99.8%	93.2%	93.6%	96.5%	94.4%	90.2%	95.2%	88.4%	84.3%	81.2%		

***Figure SI 2.6 C** Monthly total wind supply in the coming 3 months divided by the average for those months. Key: Red – Under 80%, Amber* – 80-85%, *Yellow 85-90% Green – over 110%*

The effect of the hours with low supply depends on the extent to which they are clustered. This is shown on Fig SI 2.7 for cases in which supply is less than 20% of the average for ≤ 20 hours: outliers in which low supply persists for over 20 hours are shown in Table S3 1. It is seen, for example, that in the 37 years studied there are 170 cases (averaging 4.6/year) in which supply is < 20% of the averge in 10 consecutive hours, and an averge of 7.4 cases/year in which periods with supply < 20% of the average persist for over 12 hours.

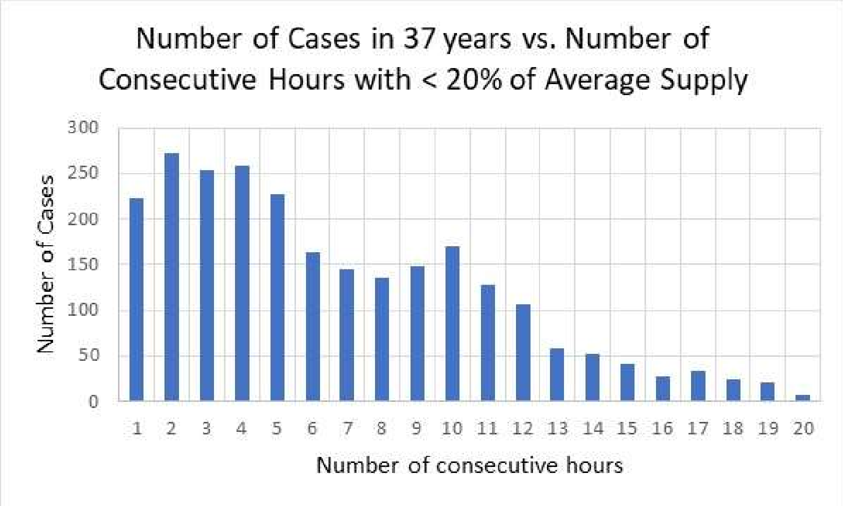


Fig SI 2.7. Number of cases in 37 years in which the 16,853 hours in which supply falls below 20% of the average are isolated hours (1 on the x-axis), persist for two hours but no longer (2), etc.

Table SI 3.1	**Outliers**						
Consecutive hours < 20%	21	22	25	30	31	32	44
Number of cases	1	2	1	2	1	1	1

The intervals between these periods of low supply may be short. A feeling for how often this happens is provided by the fact that in 37 years there are 312 days (midnight to midnight) in which supply is < 20% of averge for >11 hours, and 79 pairs of days (1 – 2 January, 3-4 January, etc) in which there are > 23 hours in which supply is < 20% of the averge.

Weather Correlations

Fluctuations in solar and wind supplies are less correlated as the distance between sites increases. Geographical spread of connected wind and solar supplies is therefore a means of reducing the short-term variability of renewable output. At a local scale, this allows for wind and solar production outside the shadow of a cloud or a single weather system. At much larger scales, such as the length of the British Isles, or the North Sea - where it is generally assumed that most additional wind turbines will be built - it would be attractive to locate wind farms far apart so as to minimise the effect of local variability and to provide a more reliable supply (as discussed further below).

Connecting different regions across Europe[4] (see SI 2.8), would smooth weather-driven fluctuations of:

- High wind regions in Northern Europe and high solar regions in Southern Europe.
- Transitory high and low wind patterns between Western and Eastern Europe.

Interconnectors will therefore make it easier to accommodate fluctuations as the role of wind and solar increases across Europe.

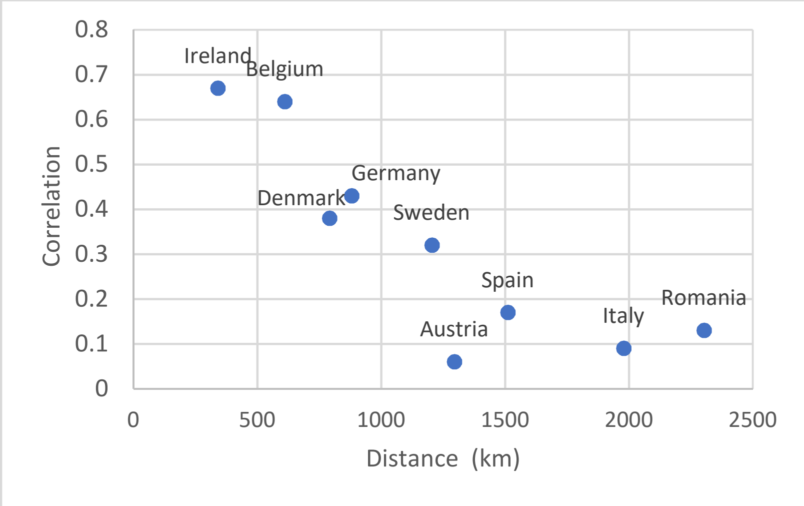


Figure SI 2.8 Correlation coefficients for wind in GB and other countries as a function of the distance between the centroids of wind power generation in each country [after Malvaldi et al. (2017) who show correlations for many pairs of countries]

However, although temporally averaged correlations fall with distance, the weather in different parts of Europe is linked: for example, in winter the North Atlantic jet stream can become tilted, leading to high wind power generation across central-northern Europe, but little generation in southern Europe[5,6]. The relationship between these large-scale weather phenomena and solar PV is not as strong[7], as solar PV production is generally low in winter, and production tends to be driven by local cloud cover conditions. Critically, *interconnection across Europe would not necessarily ameliorate the situation during winter wind droughts*, when (see Figure SI 2.6) wind supply can be very low across most if not all of Europe[5].

Siting of wind farms

Potential problems caused by periods of low wind could be somewhat eased by careful siting of future wind farms. It has been shown[8], for example, that investment in additional capacity in a north/south dipole pattern across Europe would reduce day-to-day volatility of supply, and - when they come onstream - the UK's third round offshore wind farms are expected to reduce the number of prolonged low generation events (the number of periods of 12 hours or more in which the aggregated capacity factor is less than 5% is expected to fall from 16/year to 9/year[9]). A recent study[10] of floating wind farms off Scotland, Wales, S and NE England (which projected LCOEs for floating wind farms as low as £40/MWh in 2040) identified sites with 'a potential near-term pipeline of 19.3 GW'. There is a need to study the correlations between the wind resources at these and other sites, especially at times of low wind speed, and to understand the extent to which diversification could ease periods of high stress.

Correlations between weather, wind and solar supply and demand

Table SI 2.2 shows the correlation coefficients for GB electricity demand and wind and solar generation in the period 1979-2018. Combining wind and solar improves the correlation between supply and demand as seen in Fig 2.3. The data[11] from which these correlation functions were extracted by Hannah Bloomfield are shown in Fig SI 2.9 (for October-March and April to September, and the winter months December, January, February and summer months June, July, August).

	Annual - mean	Winter-mean	Summer-mean
Demand vs wind	-0.14	-0.60	0.43
Demand vs solar	- 0.43	0.31	-0.66
Wind vs solar	- 0.21	-0.18	-0.50

Table SI 2.2 Correlations between GB electricity demand and wind and solar generation. Here winter means in December, January and February, while summer means in June, July, August (kindly provided by Hannah, based on ref 12).

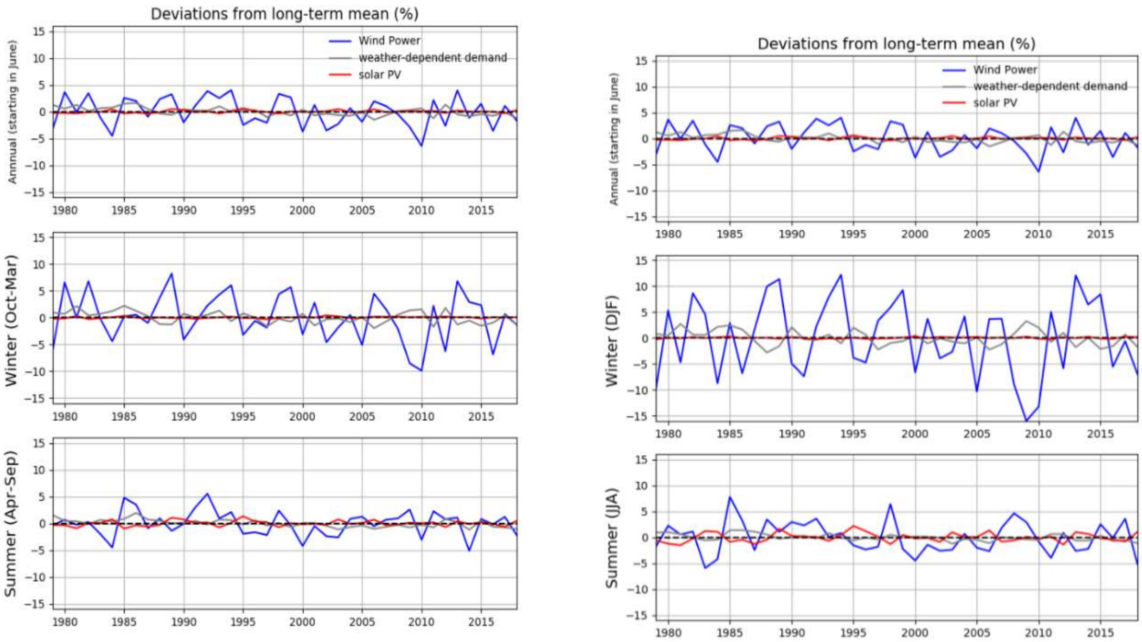


Figure SI 2.9: Correlations between demand and wind and solar supply

The correlation between wind and weather has been studied by many authors, including Thornton et al[12] who, noting that - due to its intermittency - the ability of wind to provide power during periods of high electricity demand has been questioned, characterised the winter relationship between electricity demand and the availability of wind power. They found that "Although a wide range of wind power capacity factors is seen for a given demand, the average capacity factor reduces by a third between low and high demand. However, during the highest demand average wind power increases again, due to strengthening easterly winds", i.e. the effects are not linear. Their paper provides detailed information on the correlation and its origin.

At high levels of wind and solar, fluctuations in supply will be much bigger than in demand. With, for example, solar plus wind supply (mixed 20/80) scaled to average 700 TWh/ 80 GW/year, it varied from 0.3 GW to 194 GW over the 37 years studied according to the Ninja Renewables model. In contrast, in 2019 (the last pre-lock down year) demand varied from 19.5 to 49.1 GW. According to the AFRY model, which assumes that peak demand is flattened by demand management measures, 2050 demand will vary from 43 to 98 GW. Fluctuations in residual demand will grow as more space heating is electrified, since high heating demand is correlated with low wind speeds during winter anticyclones, but this effect will be partly offset by falling demand for heating as temperatures rise due to global warming and by further improvements in insulation.

The AFRY future demand model, used in this paper, has a basic demand that relates to 2018 and hence its weather. It includes the effects of weather variation for that year, but beyond this does not include any correlations with the weather for other years studies. The extent to which neglecting correlations matters is analysed in Annex SI2 1 using a simple model of quarterly demand, based on 18 years of real data for demand for electricity and for gas for space heating, in which heating is electrified. The model was used to study the very large correlations that will occur in the case that all heating is electrified, and to compare combining the wind and solar generation with the model of demand in i) each of the 18 years and ii) the first year repeated 18 times (as done in this study with the AFRY model). It was found that:

i) Although fluctuations in electricity demand will increase as more heating is electrified, their size will typically remain less than half that of fluctuations in supply with the 80/20 mixture of wind and solar studied in this report.

ii) Correlations between demand and supply fluctuations will grow, but according to the model the correlation between supply and demand is at most moderate in Q3 (-0.65), and is weak in other quarters (- 0.29 in Q1, + 0.39 in Q2, + 0.25 in Q3).

iii) When averaged over a year, the correlation between fluctuations in demand and supply for an 80/20 mixture of wind and solar, are weak. Furthermore, they may be washed out when averaged over periods of more than a few years.

Consequently, it is probably safe to neglect correlations between supply and demand for quantities that are only sensitive to behaviour over long periods. These are:

- The choice of the wind/solar mix (which takes account of all 37 years of data).
- The need for very long-term (decadal) storage (which, it is argued in Chapter 3, should include large contingency to allow for rare weather events): the required storage rates may be affected slightly as including correlations will alter the spectrum of surpluses, but the model calculations described in Annex SI2 1 suggest that the change will be slight (discharge rates are always taken to be sufficient to meet 100% of demand for the long-stop long-term store)

Neglecting year-to-year correlations between weather and demand may lead to underestimates of the need for storage on timescales of a year or two, and shorter time scales although:

- The models used in this report cannot address very short term needs as the minimum resolution is one hour.
- Demand management will moderate the need for relatively short-term storage.

Correlations based on historical temperatures are included in the UCL's ESTIMO model, which as described in Annex SI2 2 has been used to study residual demand, and in other modelling of storage in GB[22]. It would be in principle be possible to use meteorological records over the 37 years for which Ninja Renewable data are employed in this report to build temperature related variations into models of demand, such as the AFRY model. However, this would involve taking views on future demand for heating (which will change as insulation is improved), and cooling, and how it will be supplied, which is unclear, and on the future degree of demand management. Ideally modelling should include changes in the temperature, and fluctuations thereof, due to climate change, which will also lead to alterations in weather patterns, as discussed above. In the absence of such modelling, quantitative conclusions on short/intermediate and possibly long-term storage should be treated with some caution, although the substantial contingency that is included in the size of the long-term hydrogen store, as protection against rare weather events, and possible effects of climate change, also provides protection against underestimates of the need for storage since it is available on all, except very short, time-scales.

Wind Droughts and Periods of High Demand

In the summer, wind power can fall to very low levels for periods of over 24 hours and occasionally 30 days. It is, however, winter wind droughts, which occur when wind speeds over the North Sea are low and demand is high because cold air is present over many parts of central and Northern Europe, that pose the biggest challenge to very high renewable systems. Bloomfield et al[13] studied the top ten periods of peak residual demand produced by winter wind droughts and very low temperatures in the period 1980-2019. The events, whose characteristic are shown in Figure SI 2.10, span Europe and typically last one to two weeks.

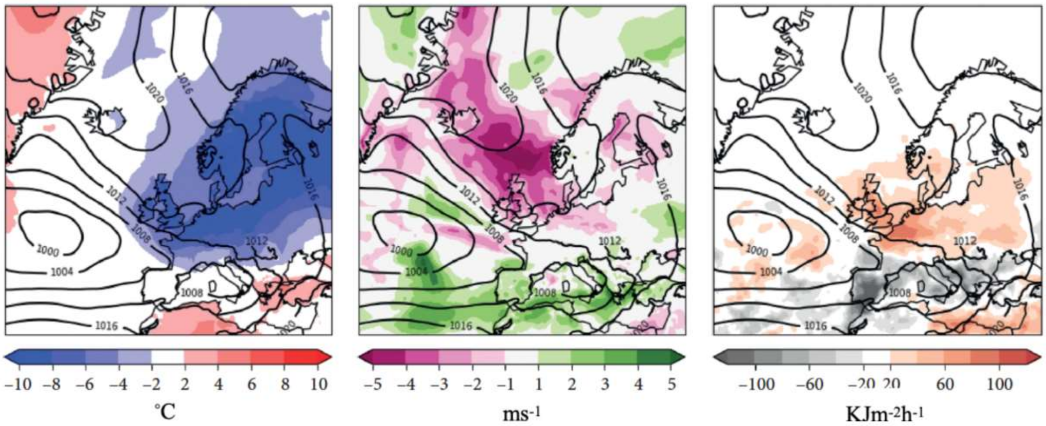


Figure SI 2.10 Average, over top ten periods of residual demand (defined relative to wind and solar output in 2017) in the period 1980-2019, of the deviation from the mean (for the days on which each event occurred - all were between 10 December and 21 February) of temperature at 2 m, wind speed at 100m, and solar irradiance.

Climate Change

Rising temperatures will decrease demand for space heating and increase demand for cooling. The effects of climate change on wind and solar supply are, however, not clear cut.

Year-to-year variability of wind power (and to a lesser extent solar) is expected to continue at the level seen today, and it is expected that this variability will have a bigger impact on supply than climate change[14]. Projected changes in wind speed and solar irradiance differ between models and are highly uncertain, as stressed by Bloomfield et al[14]. They found that while five high resolution climate model simulations of national wind and solar power generation across Europe all showed a similar and plausible simulation of the present climate, they were not able to all agree on the sign of the future change in national wind power and solar PV generation, let alone the magnitude. Averaging results from different models can therefore lead to small values that are not representative of any individual model, and should be avoided. This uncertainty can currently only be dealt with by including contingency in models of the future wind and solar supply.

Use of Historical Weather Data

Thornton et al[15] noted that it is possible that even a 40-year period is not long enough to sample a representative range of possible changes in wind availability. The Met Office has compared the period 1980-2016 studied here with large simulations using the UNSEEN methodology[16] and historical data back to 1871. It was found[17] that in each winter there is a 1% chance of the mean wind speed in December, January or February being lower than the minimum experienced in any of these months in the period 1980-2016, i.e. **there is approximately a 10% chance/decade of a winter month with wind speeds lower than in the period 1980-2016 considered in modelling here.**

More needs to be known about the persistence and other characteristics of periods of low wind, which are very likely correlated temporally, as is the case for periods with low temperatures (Kolstad et.al.[18] have shown that temperature anomalies of ‘at least one standard deviation above or below climatology’ in March were found to be about 20%–120% more likely than normal if the preceding February was anomalous by 0.5–1.5 standard deviations). It turns out that wind speeds were lower in 1960-80 than in 1980-2016, as a result of atmospheric blocking associated with the negative phase of the North Atlantic Oscillation[19], when low wind months such as those seen in the UNSEEN simulation were observed (phases of the oscillation last for about a month up to about a year and a half: the positive phases were relatively less frequent and had a smaller amplitude in the years 1960-1980 than in later years[20]). If/when weather data for that period have been converted into ersatz wind and solar output, it will be possible to quantify their effects. Meanwhile, in the modelling described in Chapters 3 and 8 the uncertainty is accommodated by adding contingency to the size of the hydrogen store. other possible measures are discussed in Section 8.7.

2.4 Matching demand and direct wind and solar supply

Optimising the wind/solar mix

Sharp[21], with reference to the National Grid’s then scenarios, anticipated that offshore wind will provide 43% to 64% of all GB’s wind power wind in 2035. Given greater offshore wind speeds and capacity factors, recent government enthusiasm for offshore wind, growing interest in floating wind farms, and resistance to expansion onshore, a 70/30 offshore/onshore mix is assumed for 2050 in this report. The fraction of demand that can be met directly by wind and solar was then calculated as a function of the wind/solar mix with the results shown in Figure 2.3, from which it is seen that:

1. The fraction that cannot be used directly increases very noticeably for solar shares above 40% because the seasonal profile of solar is very poorly correlated with UK demand, while wind is closer to being correlated.
2. As supply increases, the minimum moves to a slightly lower solar share. Increasing supply decreases the deficits, turning the smaller ones into surpluses. This reduces the net deficit in the summer by more than in the winter, because typically the deficits are smaller in the summer and more of them become surpluses. Consequently, wind is required to play a larger role.

The addition of baseload has the same effect as decreasing demand by a constant amount, leading to a bigger winter/summer difference. With wind and solar supply fixed, the addition of baseload would therefore require more wind/less solar. But adding baseload allows the level of wind and solar supply to be lowered, thereby increasing the need for solar (as discussed above). When compared with supply at the same multiple of (demand - level of any baseload), the optimum solar percentages are found to be essentially the same with and without baseload.

Models with higher (or lower) demand, generally assume more (or less) electrification of heat, and hence a larger (or smaller) difference in demand between winter and summer. Minimising demand that is not met directly therefore requires a larger (or smaller) admixture of wind.

Comparing results with models of 570 TWh/year and 700 TWh/year demand, it is found that with i) supply = demand – any baseload, the optimal solar share with 700 TWh/year demand is about 0.9 percentage points lower than with 570 TWh/year demand, with and without baseload, and ii) with supply = 1.3 x (demand – any baseload) it is about 1.1 percentage points lower.

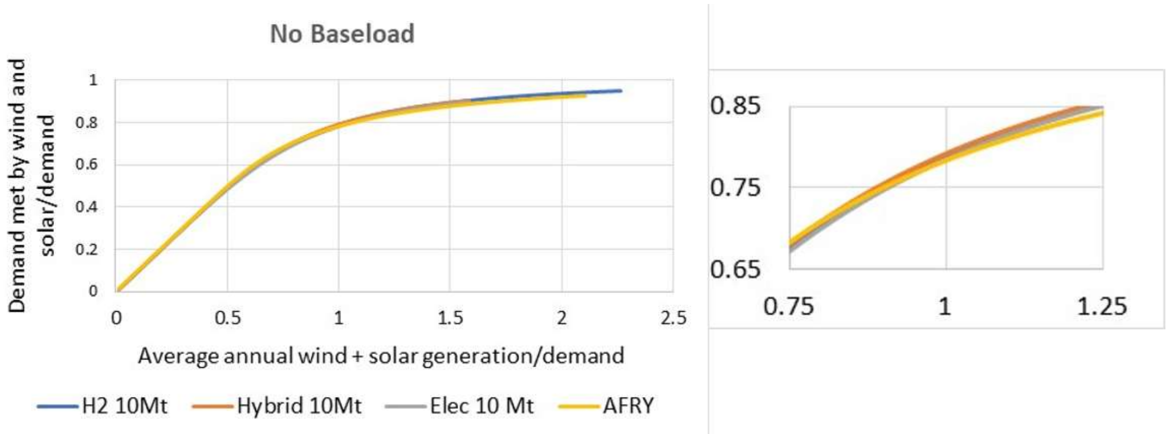
The solar/wind mix has been studied by Cárdenas et al[22], who also found around 20% solar to be optimal for current electricity demand and current solar and wind supplies, and by MacLean et al[23]. They combined electricity and estimated gas demand for space and hot water heating to create a daily profile of what electricity demand would have been in the period 2015-19 if gas heating had been electrified with heat pumps with coefficients of performance 3 in the summer and 2.5 in the winter. They then took actual wind and solar output, mixed them in varying proportions, and worked out the residual demand as a function of the proportion. They found a rather flat minimum in the cumulative residual demand in 2018 at a solar contribution between 10 and 20%, consistent with the work of Cárdenas et al, and the results found by the UCL group that are described below.

Fig 2.5 shows that when averaged over 37 years the net deficits/surpluses are approximately zero with an 80/20 wind solar mix. With 30% solar, the mean surpluses/deficits in Q1-Q4 are -17.7, 13.3, 12.8, - 8.3 TWh respectively, and there is a noticeable (although small compared to volatility) surplus in the summer; with 10% solar, the corresponding numbers are 0.4, - 8.5. - 6.1,14.3 TWh, and there is a surplus in the winter.

2.5 Residual Demand, Energy and Power

Residual Demand

Figures SI 2.11 shows residual demand (without baseload supply) as a fraction of demand according to the AFRY model (as plotted in Fig 2.6), and three models with very different temporal profiles, which were developed using Imperial College's ambitious Integrated Whole Energy System model[24] [ii] of demand, supply, transmission and costs.



[ii] In which it was assumed that demand will be shifted to the middle of the day (at what cost is unclear) to match solar supply: the results is that hourly demand in every quarter in all three models is peaked around mid-day (in sharp contrast to today), and from 1 pm declines at a steady rate onwards to its night-time minimum. Demand reaches very high levels (217 GW in the high electrification model, over three times the maximum demand today), and the difference of demand in different quarters has surprising (but not necessarily incorrect) features, e.g. the average peak is the same in Q4 as in Q2 and Q3 in two of the three models. Not surprisingly, the solar/wind mix favoured by this model is around 30/70 – much higher than found with more conventional demand profiles.

Figure SI 2.11 Residual Energy as a function of Renewable Generation for three IC models (see ref 21 for a definition of the scenarios) and the AFRY model of demand, with 37 years Ninja-Renewables wind and solar data, mixed 80/20 as described in the text. The inset on an enlarged scale is designed to facilitate comparions.

It is seen that the results in models with different levels, and very different profiles, of demand are essentially indistinguishable. This is also true to a first (but not quite so good) approximation with a constant baseload supply meeting 25% of demnd, as shown in Fig SI 2.12:

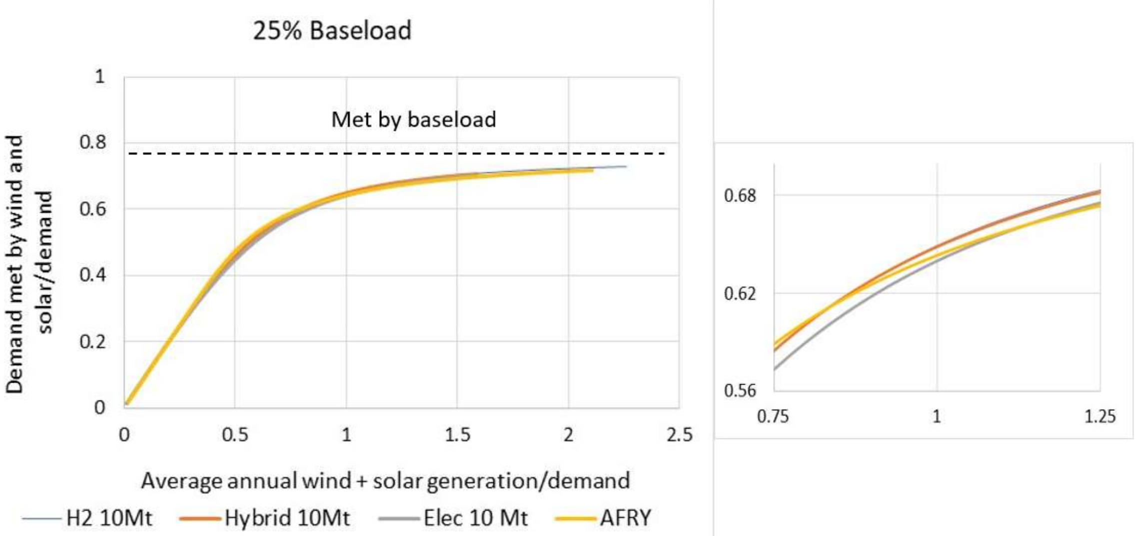


Figure SI 2.12 As in SI 2.11 with a constant baseload supply meeting 25% of demand

In order to understand demands on storage and flexible complementary supply, it is helpful to examine the fraction of time during 37 years when renewable supply is in surplus or in deficit, which is shown in Figure SI 2.13 in the AFRY model (570 TWh/year demand) for different levels of supply. This figure shows that renewable supply of 741 TWh/year (1.3 times demand) would on average be in surplus for 63% of the time (in the best/worst years it would be in surplus 69%/59% of the time): this is reflected in the results of modelling described in Chapter 4, which show that (for example) with stand-alone compressed air storage the optimum output power (needed when there is a deficit) is greater than the input power (needed when there is a surplus).

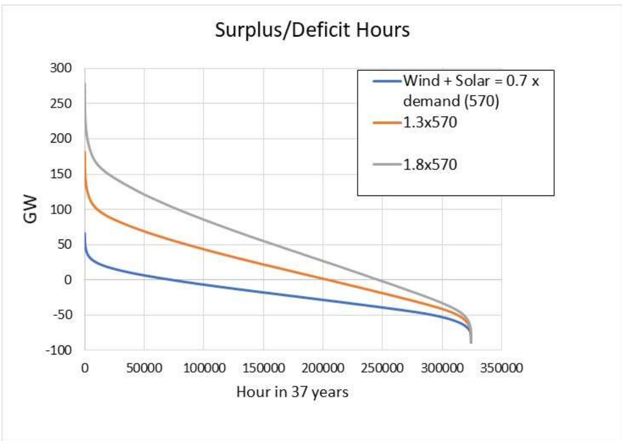
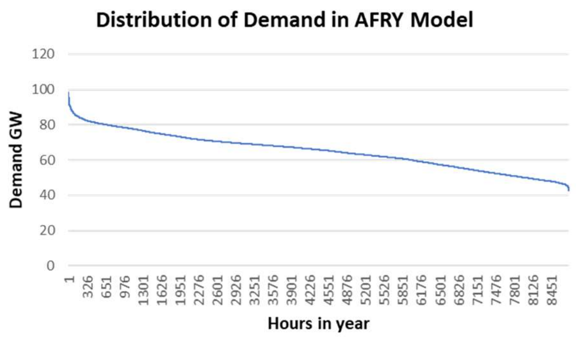


Figure SI 2.13 Difference of renewable supply and demand in each hour over 37 years, arranged so that the hour in which it is largest is on the left, with the number of hours in which a given value occurs is shown on the x axis, for supply equal to 0.7-, 1.3- and 1.8-times demand.

Residual Power

The large residual demand for power seen at the right-hand end of SI 2.13 was shown in Fig 2.9. Whatever meets low demands for energy that are coupled with high demands for power (whether it be storage or supply from other sources) will operate with a low load factor and will therefore be expensive. However (as anticipated in Chapter 1 and seen explicitly in Chapter 8), the average cost of power need not become exorbitant thanks to the relatively low cost of wind and solar which meet most of demand.



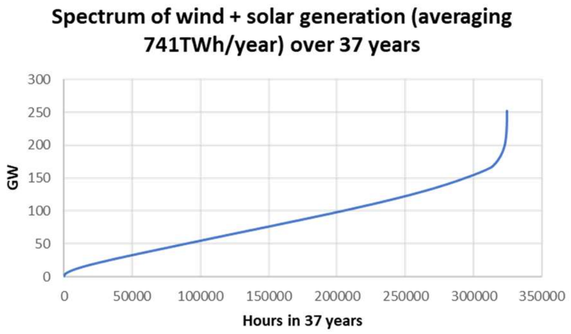


Figure SI 2.14 Left – distribution of residual demand in the AFRY model, in which very high demand is relatively rare (it is > 80 GW/90 GW/95 GW during 7.5%/4%/1% of the year: the temporal distribution of periods in which it is > 80 GW is shown in Figs 13-14 and 13-15). Right - spectrum of wind and solar supply: low supply is not uncommon (it is <10GW/20 GW/30 GW in 2.0%/7.1%/13.5% of the time).

Figure SI 2.14 shows the spectra of demand for power in the AFRY model and of wind and solar supply in the Ninja Renewables model. The model, which does not fully take account of correlations between supply and demand finds (see Figure 2.9) a maximum residual demand of 88.2 GW. However, in the AFRY model the maximum demand is 98.4 GW while the minimum wind and solar supply is 0.4, and as remarked in the Report if correlations were properly incorporated maximum residual demand would be close to or could reach 98GW.

There are models in which peak demand is higher than in the AFRY model (in one of the IC models it is 217 GW). However, demand side measures, such as those below, which are included in the AFRY model, can reduce peak demand, and adopting them should be an imperative. In the National Grid's Consumer Transformation, System Transformation and Leading the Way scenarios[25], which assume inter alia smart charging of EVs and no networked electrolysis at peak time, the 'average cold spell' peak demands (which are 'A measure of hypothetical maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period') in 2050 are 112.9 100.8 and 112.9 GW respectively. This encourages a cautious belief that peak demand can be limited to around 100 GW with basic demand of around 600 TWh, and this is assumed in this report when costing storage, although the impact of allowing for higher surges in demand is considered in Chapter 8. However, as stressed in section 2.10 and 2.2, periods of very high residual demand tend to cluster, and although demand management is important for flattening peak demand, it cannot deal with prolonged wind droughts.

Periods of high demand

In view of the particular demand that periods of high electricity demand put on the electricity system, it is worth analysing them in more detail. showed that according to AFRY's model (Fig SI 2.10) demand is only above 80 GW during 7.5% of the year. The distributions of the periods when this happens is seen in Fig SI 2.15.

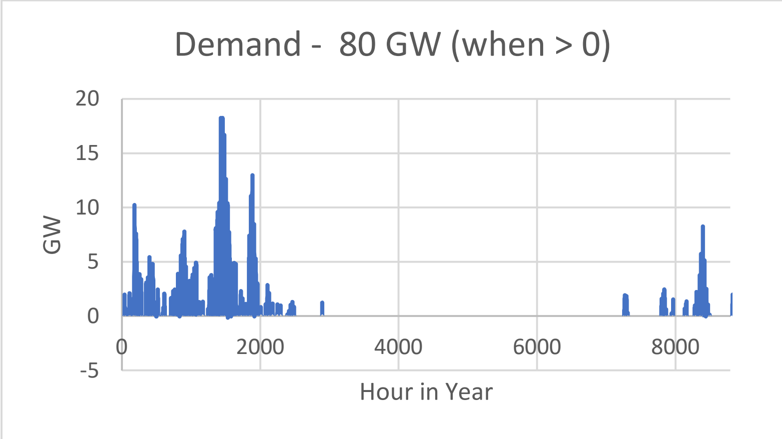


Figure SI 2.15: Hours in the year in which demnd in the AFRY model is above 80 GW.

Figure SI 2.16 shows the first 3000 hours in the year in more detail. The volatility seen in this plot reflects the volatility of the weather, which affects demand (the AFRY model is based on the weather year 2018). High demand is often correlated with low temperature, which is correlated with low wind speeds, and consequently the volatility of residual demand is much greater. As discussed above, periods of high residual demand cluster, as seen here for periods of high demand. It was found in section 2.7 that demand side measures may be able to reduce demand by up to 20 GW for short periods. However, some of these measures are already included in AFRY's model of demand, and given the clustering seen in this figure it is hard to imagine that additional measures (beyond those considered by AFRY) could reduce the peak by more than 8 GW or so.

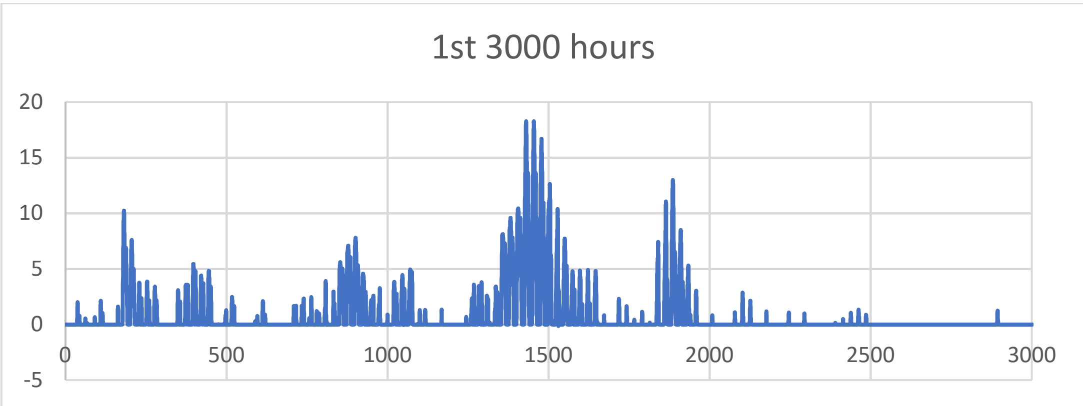


Figure SI 2.16 Hours in which demnd is > 80 GW in the first 3000 hours of the year according to the AFRY model

UCL Estimo Model

The UCL Energy Institute Energy Space Time Group has undertaken an interesting study as input to this report, using their own model of demand and MEERA weather data. Their report, which is included below in full as Annex SI2 2, contains a wealth interesting information, primarily about residual demand and especially about heat, including for example the breakdown of electricity demand in their model into demand for space heating and for heat used for other purposes (Fig 9 – references to Figure numbers in the is section are to the Figure numbers in Annex SI2 2).

The model simulation assumes a high degree of electrification of the provision of heat, leading to total electricity demand of 700 TWh/year, which takes account of the relationship between space heat demand and heat pump Coefficient of Performance and temperature (Figs 3 and 11). Demand for electricity for heating varies inter-annually by +/- 25 TWh. While this is +/- 14.5% of electrical demand for heating, it is only +/- 3.5% of total demand for electricity, even with the complete electrification of heat using air source heat pumps.

There is a deficit of renewable energy in the summer and a surplus in the winter as a consequence of the modelled solar share of supply being only 11%. In the model average supply is assumed to be bigger than average demand, by an amount that varies from year to year Fig 13) but averages 18 TWh/year (Fig 14) leading to a cumulative residual demand of 560 TWh for the 31 years studied (Fig 14).

Annual renewable supply varies by + 85/-60 TWh/year, as shown in Fig 13. It is not correlated in any obvious way with electricity demand (as expected given the absence of significant correlations over six-month periods found in the simple model described in Annex SI2 1), e.g. both 1986 and 2010 show exceptionally high levels of demand for space heating, but renewable supply was a maximum in 1986 and a minimum in 2010. Residual energy fluctuates inter-annually from - 66 to + 82 TWh (-10% to +12% of mean annual demand, while the maximum cumulative difference varies by about +/- 60 TWh, or +/- 10% of average annual demand. There is no obvious correlation between cumulative surpluses and deficits in sequential years.

2.6 Generating Costs

Wind and Solar

BEIS's projections[26] of the cost of wind and solar generation in 2040 are reported in Table SI 2.3, together with the weighted averages for 2040 and 2035 with the mix discussed above.

BEIS 2040 Projected Levelized Cost of Electricity					2040
£ (2018)/MWh	Offshore wind	Onshore wind	Large-scale solar	Weighted average*	Weighted average*
High	44	50	39	44.4	47.3
Central	40	44	33	39.6	41.8
Low	36	38	28	34.9	37.2
* 80% wind (7/3 offshore/onshore) + 20 % solar					

Table SI 2.3

The discussion of 2050 costs in this report uses weighted averages of i) £35/MWh (2020 prices) ii) £45/MWh and iii) of £30.2/MWh found using the 2040 projections in the 2020 World Energy Outlook[27] with the capacity factors the WEO assumes for Europe replaced by those assumed by BEIS for the UK. £35/MWh (just above BEIS's low 2040 projection) is taken as the central value since BEIS's projected costs still appear to be falling in 2040 (a simple-minded extrapolation of BEIS's low projections gives £30/MWh in 2050), their past projections have tended to be pessimistic, and it is above the IEA projection.

Complementary Generation

Nuclear

Cost: in most of the modelling described in Chapter 8, a 2050 nuclear generating cost of £78/MWh is used, which is BEIS's central projection for an n^{th} of a kind PWR commissioned in 2030 assuming an 8% discount rate. Results are also quoted for BEIS's high and low projections, of £69/MWh and £99/MWh. The cost could be significantly lower if the proposed **R**egulated **A**sset **B**ase Model of financing is adopted and achieves its aim of reducing the risk for investors and hence lowering borrowing costs. If the build costs envisaged by the Rolls Royce led Small Modular Reactor Consortium are achieved, and many are built, they could deliver electricity for as low as £55/MWh[iii]. The costs quoted by BEIS include £5/MWh for the cost of fuel and £5/MWh for operation and maintenance and assume a load factor of 90%[28]. With these values, a total cost of £78 [55]/MWh with 90% load factor would correspond to £(10 + 61.2 [40.5])/(load factor) in other cases. In 2022 the UK government announced an ambition that there should be 24 GW nuclear capacity in 2050[29]. With the 2017 value of the UK's average nuclear load factor of 77.4%[30], which was 0.9 percentage points above the European average (the 1970-2017 average was 67.4%, 5.2 percentage points below the European average), this would provide 163 TWh/year.

Flexibility: Most modern light water nuclear reactors can change their power level once or twice per day in the range of 100% to 50% (or even lower), with a ramp rate of up to 5% (or even more) of rated power per minute[31]. Operation below the maximum level increases the average generating cost, but the electricity supplied to the grid can be rendered flexible by adding thermal storage (see Chapter 5) or using part of it to generate hydrogen[32] while operating the reactor in steady state (see SI 8.5).

Environmental credentials: existing legislation is designed to ensure that operation and the disposal of waste are done safely with little if any environmental impact.

Limitations: the time taken to obtain planning permission and build nuclear plants – which may face public opposition – may limit its role in 2050, which will also be very dependent on expected costs.

Gas with CCS

Cost: BEIS[26] projects a 2040 Levelised Cost of Electricity (LCOE) of £82/MWh for an n^{th} of a kind gas Combined Cycle Gas Turbine (CCGT) equipped with post combustion CCS, assumed to be 47% efficient, with a 92% load factor (net of expected availability), including £47/MWh for the cost of natural gas, which is assumed to cost 65p/therm/MWh. With the other assumptions kept the same, the cost projection varies with load factor as (£62 + £18.4/load

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[iii] BEIS's most recent (2016) low/central/high LCOE projections for an n^{th} of a kind PWR commissioned in 2030 are £69/78/99/MWh for a discount rate of 8.8% – but as low as £40/44/51/MWh for 3.5%. It is expected that BEIS will shortly announce that the UK's next nuclear project will be financed using the **R**egulated **A**sset **B**ase Model, which is designed to reduce the risk for investors and reduce borrowing costs, and could possibly lower BEIS's low and central projections to under £50/MWh. Costs could also be lowered by building multiple identical **S**mall **M**odular **R**eactors (which would benefit from shorter build time, thereby lowering the borrowing costs, standardisation, and learning). According to the Financial Times of 17/5/21, Rolls-Royce 'expects the first five reactors to cost £2.2bn each, falling to £1.8bn for subsequent units'. The FT quoted the Chief Executive of the Rolls-Royce-led SMR consortium as saying that the generating cost will be 'around £50/MWh'. Details and updates can be found on the Rolls-Royce web site.

factor)/MWh (where the variable cost includes £8 for 10% uncaptured CO2 at what appears to be an assumed carbon price of £220/t).

Flexibility: According to the International Renewable Energy Agency[33] 'flexibility initiatives' could increase the ramp rate of CCGTs from the current average value of 2-4%/minute to 8-11%/minute, although they would not change the minimum up- and down- times, of 4 and 2 hours respectively. With effective control systems and management, it is not expected that the ramp rate would be compromised by adding CCS[34].

Environmental credentials: Gas plus CCS produces greenhouse gas emissions comprising:

a) Uncaptured CO2, of 0.0380 Mt_e/TWh assuming generation with 47% efficiency[26] and that 90% can be captured.

b) Upstream methane emissions, of 6.91×10^{-4} Mt methane/TWh_e/year for power generated with 47% efficiency if leakage can be limited to 0.5%. Leakage of a pulse of a tonne of natural gas produces a temperature rise that is 80, 55, and 32 times larger than that produced by a pulse of a tonne of carbon-dioxide after 25, 50, and 100 hundred years[iv]. However, it is more realistic to consider emissions by steady sources rather than pluses. As discussed in SI 8.5, steady emissions of methane would lead to a temperature rise 128 times that produced by steady emissions of an equal mass of CO2 in the first 20 years after the emissions start; the factor of 128 drops to 8 after 20 years, leading to a temperature rise 88 times that produced by steady emissions of CO2 after 30 years, and 32 after 100 years.

The questions of whether a CO_2 capture rate of 90% or more can be achieved and leakage limited to 0.5% are discussed in SI 2.6: the Climate Change Committee (CCC) more ambitiously assumes[35] 95%, but the only commercial (coal) power plant equipped with CCS[36] recently lowered its target from 90% to 65%[37].

Limitations: With the figures above, 100 TWh/year generated by gas + CCS would result in 3.8 Mt/year of CO_2 emissions with methane emissions 'equivalent' to 8.8 Mt/year of CO2 emissions in the first 20 years after the emissions start, falling to the equivalent of steady emission of 2.2 Mt of CO_2 after100 years. Emissions on this scale should if possible be avoided since they would have to be offset in a net zero world, in strong competition with demands for offsetting of emissions that are extremely difficult to avoid (e.g. from industrial process and aviation), for which the use of the UK's limited capacity for offsetting should be reserved (a Royal Society Report[38] identified a possible 130 Mt/year of negative emissions in the UK of by 2050, including a possible 25 Mt from Direct Air Capture, but found that i) greenhouse gas removal at this scale would be 'very challenging and costly', and ii) only 35 Mt/year is ready for deployment[v]). Similarly, large-scale reformation of methane to make 'blue' hydrogen, which is discussed in SI 8.5, should if possible be avoided.

Bioenergy with Carbon Capture and Storage (BECCS)

Cost: A report for BEIS[40] estimates a cost of £181/MWh for post combustion amine capture (in which BEIS has 'greatest confidence') and £138/MWh for chemical looping for n^{th} of a kind

[iv] Numbers provided by Myles Allen (private communication), obtained using the assumptions employed by Myhre et al in Chapter 8 of the 5th IPCC Report.

[v] Offsetting emissions from a gas + CCS power plant with Direct Air Capture costing \$Nx100/(t CO_2) would add \$Nx11.2/MWh to the cost of power, using the figures above and the 25-year CO_2 equivalence of methane: without CCS, the additional cost would be some \$Nx41/MWh for a 56% efficient gas plant. As discussed below, Carbon Engineering projects values of N between \$94/t and \$232/t.

plants coming into operation in 2031, assuming their central value for the fuel cost, and an 90% load factor. BECCS being carbon negative, these costs would be more than fully offset by a carbon credit of £190/tonne (the 2040 carbon cost assumed by BEIS).

Flexibility: The ramp rate for producing power by burning biomass is a few percent per minute, similar to that for coal, and - as in the case of coal - it is not expected that it will be changed by the addition of CCS[39].

Environmental credentials: BECCS has the major advantage that (*provided the biomass is carefully sourced*) it provides large negative emissions (1.0/1.3 t CO2/MWh_e for chemical looping/post combustion amine capture according to a study carried out for BEIS[40]).

Limitations: Modelling of UK and global biomass feedstocks carried out by Ricardo for BEIS, found that a total of 100 TWh of UK sourced solid biomass will be available in 2050, when another 37 TWh (some 2% of the global resource) is expected to be available internationally[41] (down from an estimated 189 TWh in 2030 as a result of increasing global competition for biomass). With BEIS's assumption of 30% efficiency for post combustion CCS, these estimates (which are uncertain – very uncertain in the case of imports), suggest that in 2050 BECCS could provide the UK with some 40 TWh_e.

Other Sources

Other renewables: DUKES reports that in the UK in 2019: 5.9 TWh were provided by hydro and 37.3 TWh by biomass (22.3 TWh by plant mass: with, in decreasing order of importance, biodegradable waste, landfill gas and anaerobic digestion each providing over 2 TWh). The International Hydro Association reports[42] that 'Despite an estimated 2.4 GW of viable hydropower potential in the UK *[in addition to 4.7 GW installed today]*, hydropower expansion is likely to be limited to small-scale applications (up to 5 MW), with the exception of pumped storage projects' – which are considered in Chapter 5. The contribution of plant mass is expected to grow in the form of BECCS, but otherwise there seems to be no prospect of additional multi-TWh renewable contributions, although in principle the UK has a large potential for tidal and wave energy.

Blue hydrogen and ammonia: The 2020 White Paper and BEIS's latest report on electricity generation[43] envisage up to 20 TWh_e/year being provided by 'blue' hydrogen, produced by methane reformation with CCS, which is seen as an important source of flexible power (it is not said how the hydrogen would be converted to power, or with what efficiency). The fugitive CO_2 and methane leakage would have to be offset to achieve net zero, and unless the SMR process were operated flexibly - which appears to be possible[44], but would put up the cost - hydrogen storage would be needed. This possibility is considered in SI 8.5, which explores the possibility of all or most flexibility being provided by power ↔ (green) hydrogen storage. The possibility of using imported ammonia, produced cheaply in countries with abundant solar resources, to provide flexibility is considered briefly in the discussion of contingencies in SI 8.7.

Gas peaking plants. Some scenarios include small contributions from very flexible peaking plants, which would run only when there is very high residual demand at a level such that the uncaptured CO_2 emissions could be deemed acceptable, e.g. 0.6 TWh/year from 35% efficient peaking plants would produce 0.31 Mt of CO2, with negligible upstream emissions. Contributions on this level have a completely negligible impact on the need for and cost of providing storage.

Comparison of the flexibility of different sources.

With high levels of (volatile) renewables, the complementary supply must include a substantial component that is flexible, which however will have to operate with a very low load factor (with e.g. an average 741 TWh/year of renewable supply, the average load factor on the complementary supply, which must be able to provide 100 GW when the wind is not blowing and the sun not shining, would be about 10%). Apart from stored renewable energy, the large-scale low-carbon candidates are BECCS, nuclear and gas with CCS. However, not only is BECCS rather inflexible, but it would seem that once built it should be operated with the highest load factor possible given its important role in removing CO_2 and its high cost. Both nuclear and gas can be operated fairly flexibly, but comparing BEIS's central values of £(63 +17.5/(load factor))/MWh for gas with CCS and £(10 + 61.2/(load factor))/MWh for nuclear, it is clear that at low load factors nuclear would be intolerably expensive. This is not to say that nuclear could not play an important role in providing baseload.

CO_2 Leakage in CCS, Methane Leakage, and Direct Air Capture

CCS[vi] and methane leakage in power generation and steam reformation of methane and Direct Air Capture

The American Chemical Society has recently published a review of the outlook for CCS and Direct Air Capture[45] CCS.

Power generation: BEIS[28] assumes 47% generation efficiency and 90% capture. More optimistically, the CCC assumes i) 56% efficiency, which is very high given that CCS uses energy, and ii) that 95% can be captured, which is possible in principle but would put up the cost.

Capturing CO_2 with amines is the incumbent technology, but the ACS review sees the use of solid sorbents or membranes as promising next generation technologies. Close to 100% of CO2 emissions can be captured in the Allam/Allam-Fetvedt cycle [Energy Procedia. 114 (2017) 5948], which is based on oxy-combustion and the use of CO2 as the working fluid[46]. Claims that this cycle can be cost competitive with generation without CCS assume that CO2, and also Argon and Nitrogen (co-produced in the Air Separation Unit), can be sold - but the market for these gases is already well supplied. The high capture rate could justify a much higher cost, once it has been proven at scale (a 50 MW_{th}/25MW_e demonstrator has been in operation since 2018, and a NET Power is building a 300 MWth plant that is due to be commissioned in 2026), although the problem of upstream methane emissions would remain.

Upstream methane emissions: In a study which concluded that emissions along the supply chain need to be better measured, and the potential for and cost of reducing them needs to be better quantified, Imperial College's **S**ustainable **G**as **I**nstitute[47] found that the median of recent leakage rate estimates is 1.6%. It has been claimed[48] that in a single very tightly controlled supply chain leakage could be as low as 0.1%. However, if the UK uses gas to provide substantial amounts of power, it would probably not be realistic to assume anything below 0.5%, which is at the lower range of the estimates in the SGI's report[vii].

[vi] The term CCUS seems to be replacing CCS. The prospect of use (the U in CCUS) makes CCS sound more attractive, but few large-scale uses for CO2 are known. Those who use the phrase CCUS should say what use they have in mind.

[vii] Thanks to Adam Hawkes of Imperial College for a discussion of leakage

Steam methane reformation: Whether the heat needed for the reformation reaction is provided by burning natural gas (as most commonly done today) or burning some of the hydrogen that is produced (autothermal reforming), CO2 emissions of some 3.3 [1.65] Mt/(100 TWh hydrogen) would remain with a 90% [95%] capture rate[viii] (95% is plausible in auto thermal reforming as the CO2 stream is relatively concentrated). Assuming 0.5% methane leakage, and an equivalence' factor of 128, this methane would produce the same temperature rise as (7.7 Mt/year of CO2)/(100 TWh hydrogen) during the first 20 years after the emissions begin. These numbers suggest that hydrogen should only be produced on a 100 TWh/year scale if methane emissions are very tightly controlled, and would appear to exclude production on anything like the 700 TWh_{th}/year scale envisaged in the Committee on Climate Change's full hydrogen scenario[49].

Direct Air Capture: Carbon Engineering[50] projects costs between $94/t and $232/t. The ACS review (loc. cit.) quotes the CEO as saying that the firm is 'extremely confident its cost will be in that range and expects second and third generations will ensure costs of $100' but says that 'industry insiders estimate [costs] are around $500/t'.

Interconnectors

Connections between national electricity grids allow countries to share supplies and smooth fluctuations in residual energy and demand. In the limit, a global grid could provide continuous daytime solar and wind power, generated in unrelated weather systems, to regions in which the timing of demand is completely uncorrelated. While this is impractical in the foreseeable future:

- Great Britain currently has 7.4 GW of interconnector capacity: 3 GW to France, 1GW to the Netherlands, 500MW to Northern Ireland, 500MW to the Republic of Ireland, and a 729 km 1.4 GW link to Norway. According to National Grid, 90% of the electricity imported by interconnectors will be from zero carbon energy sources in the future[51]. It is possible that by 2050 some 25 GW of interconnectors will be in operation (one FES assumes 28 GW).
- A 3,800 km undersea link from Morocco has been proposed by Xlinks[52]. They plan to build 10.5 GW of wind and solar generating capacity which, supported by battery storage, could deliver 3.6 GW to the UK for an average of 20+ hours a day (providing a valuable 26+ TWh/year), 'enough to power over 7 million homes' (= over 23 TWh/year at Ofgem's rate of 3 GWh/home/year). Undersea connections are expensive. The costs of the recently opened links to France and Norway were £2.9m/GW/km and £1.4m/GW/km respectively, and conversion losses (of 0.7-0.8% at each end[53]) and transmission losses (of 3% per 1000 km[54]) are not insignificant. However, Xlinks believe[55] that the project would be financially viable if payments of £48/MWh (which is below the generally anticipated 2050 wholesale price) were guaranteed for 25 years under the current CfD mechanism. Supply chain issues (which Xlinks hope to reduce by building cable plants, and commissioning cable laying ships[56]) would make it difficult to install much more than already proposed by 2050, and supply would be vulnerable to political developments and physical interference with the cable. This interesting proposal is therefore not considered further in the report.

[viii] Emissions would be lower if the heat were provided electrically, but this possibility does not seem to have attracted any interest.

Models of a connected electricity system across Europe[57,58] found that interconnection could substantially reduce residual demand, assuming the system becomes collectively managed. The distances between Eastern and Western regions reduces the effect of local weather variation, while the connection between Southern and Northern Europe provides a balance between areas where solar and wind dominate. The inclusion of different time zones modifies the peaks in demand somewhat. These factors ameliorate the intermittency of renewables, and - for a perfectly connected 100% renewable system across Europe - could reduce maximum residual demand by 33%[57]. Recent Modelling by Price et al[59] (which is described in SI 3) found that increasing interconnector capacities across Europe from those proposed for 2027 (16.5 GW of interconnection of the UK with Europe, including land-based transmission between Northern Ireland and Ireland), up to a limit of 50 GW per link, and allowing hourly net imports into the UK to peak at 50% of total hourly demand, would lower the average cost of electricity in the UK by some around 5%, depending on the other assumptions.

In the contiguous USA, which covers four time zones and different climatic regions, a continental scale grid would have a major impact, as shown by a study of storage[60] that is discussed in the next chapter. Currently, however, there are only low power interconnectors between the three major networks. In Asia, the development of larger grids is accelerating to meet the growth in demand and the expansion of renewables. China already has over a dozen high voltage interconnectors of over 1000 km connecting the east and the west of the country. At an extreme scale, a proposed 4,200 km underwater cable linking Australia and Singapore[61] would provide 3.2GW of dispatchable power, generated by solar PV with a peak capacity of 17to 20 GW supported by a 36-42 GWh battery. There are also ambitious plans to export large amounts of solar-produced hydrogen from Australia[62].

Stronger interconnections would make it much easier to manage the UK and European electricity systems, assuming the system becomes centrally managed. Fears have been expressed[63] that turning off exports of power to GB might be used 'as a bargaining chip', thereby decreasing rather than increasing energy security. In any case, as the role of wind energy grows, interconnectors will not be able to help greatly in the infrequent but extended periods when wind speeds are low across much of Europe. Furthermore, supplies from Norway are vulnerable to drought (in 2021 Norway was considering limiting electricity exports) and low water levels can threaten conventional generation in Germany and nuclear supply in France.

2.7 Demand Management

Residential and Industrial Demand

Recent analysis[64] for the Committee on Climate Change found that up to 53% of residential electricity demand, 32% of commercial electricity demand, and 22% of industrial electricity demand are potentially movable, albeit mostly only for a few hours. These numbers are, however, based on customers' expressed willingness to shift demand, which may not reflect their behaviour in practice (although it could be nudged by incentives). However, the potential is expected to increase as tariffs with remote switching become available, and smart metering and appliances become the norm. Detailed estimates of the potential in the UK range from 5 GW to 11 GW[65] for all sectors in 2030, assuming current demand, corresponding to perhaps 10-22 GW for the larger 2050 level of demand. However, FES 2022 show scenarios with 24 to 37 GW Demand Side Response, and the upper end of this range looks achievable:

Residential demand: Smart systems that shift demand in response to price signals (which could be large in times of stress) are already being installed for some purposes ('real time' pricing is discussed in Chapter 9). By 2050, when they will be widespread, they could provide some 20 GW of flexibility (a number which is consistent with the relative potential demonstrated in studies of the US electric grid[66]), mainly by shifting the times at which EVs are charged[67] and heat pumps operated, given the numbers that will be deployed (possibly tens of millions) and that EV chargers and heat pumps consume several kilo-watts[ix].

Industrial and commercial demand. Some industrial demand can be delayed on a planned basis and batch production can be paused without directly affecting consumers (unless production is just in time), while some services can be deferred. Commercial buildings (which account for 30% of final UK electricity consumption; residential use is responsible for some 35%) are prime targets because they contribute strongly to the rising shoulder of the evening peak in demand[68], and savings are relatively easy to achieve, by adjusting the level and/or timing of heating, cooling, ventilation, lighting, and the use of internal equipment including office equipment and elevators.

Some industrial customers are supplied under demand response contracts. Discussions with industry experts suggest that today such contracts (about which very little public information is available) allow UK supply to be reduced by up to some 12.5 GW in principle, and 7.5 GW in practice. Some of these contracts can be activated perhaps a thousand times a year but only for very short periods, others allow for (say) 10 activations/year for (say) eight hours[x].

More could be achieved by contracts that could be activated in the very rare circumstances that cause the greatest problems, in return for suitable compensation (National Grid's 2021 FES "Consumer Transformation "scenario assumes that such contracts would result in up to 16 GW of demand side response by 2050 - see fig FL.9 in the Data workbook). Experience in September - October 2021 showed that very energy intensive business may temporarily close at times of very high prices without a contractual obligation. GB's industrial and commercial electricity consumption[xi] was 181 TWh in 2019 (split almost exactly 50/50 industrial and commercial plus public service, of which 22%/32% can potentially be shifted according to the analysis quoted above). This corresponds to an average (over every hour in the year) of 21 GW, although consumption outside weekends, holidays and idle night-time periods is obviously very much greater. With sufficiently attractive demand response contacts, it would

[ix] **Electric Vehicles**. EV power demand can be shifted by up to 8 hours by controlling the rate and the timing of charging which smooths variations in overall demand. Slow EV chargers are typically rated at 3 kW, while fast chargers installed (e.g.) in car parks and in homes with off-street parking are rated at 7 KW or more. By 2050 there will be 20-33 million EVs in the UK in 2050 according to FES 2021.
Heat pumps: In order to heat a 2-bedroom flat/well insulated 5-bedroom house during a cold snap, an air [ground] source heat pump might have to consume by some 2.5 [1] - 8 [5] kW of electricity. Shifting this demand by large amounts will be difficult in poorly insulated homes, but the potential is large: according to the net-0 compatible FES 2021, the number of homes equipped with heat pumps will, in millions, range from 1.0 Ground Source + 3.0 Air Source + 7.1 Hybrid in the System Transformation scenario to 8.4 Ground Source + 8.7 Air Source + 8.1 Hybrid in the Consumer Transformation scenario.

[xx] There could also be cases in which activities could be shut down for longer periods, including ones designed to exploit periods of surplus when electricity prices are very low that can make use of power that is provided spasmodically, such as drying biomass and heating greenhouses, and others yet unthought of.

[xi]which is not expected to grow much if at all: the National Grid's 2020 Future Energy Scenarios 2050 figures ranging from 174 to 218 TWh.

seem possible to very occasionally cut peak industrial and commercial demand for short periods by some 20 GW.

Imposed and Emergency Reductions in Demand

It is possible to cap supply/reduce demand by fiat. Large reductions were imposed during the 3-day weeks in 1974 and are allowed during emergencies. While not suggesting anything on such scales and, noting that the level of very occasional reductions that would be acceptable is a political question, it is interesting to consider what level of sustained reductions might be possible in extremis to deal with very rare weather events. A 2005 IEA publication, 'Saving Electricity in a Hurry'[69] described and analysed responses to shortfalls in electricity supplies, which have occurred at one time or another in almost every country. It provided many examples, including: a 14% reduction over 9 months in California in 2002, in response to conditions foreseen a year in advance, caused by a combination of events (including a bungled transition to a liberalised electricity market, bankruptcies of major utilities, a drought, a shortage of natural gas, and policy deadlocks between regional and federal authorities); and a 20% reduction in Brazil over 10 months in 2002, of which there was 5 months warning (caused by drought - hydropower is responsible for up to 90% of electricity generation - and an economic upturn). A 2011 update[70] includes descriptions of savings of 15% in the summer of 2011 in Japan, following the Fukushima disaster in March, and of 20% - primarily in industry - in South Africa in 2008 and 2009, when investment in electricity generation had not have kept up with economic developments.

The examples given by the IEA show that large savings can be made, the largest when problems are foreseen well in advance, although they will become more painful as the energy system is increasingly electrified, The IEA's reports described the specific measures that were taken in different cases. Successful strategies include

- raising prices;
- introducing more energy efficient technologies, given sufficient advanced warning;
- campaigns to change behaviour, which when supported by mass media campaigns have proved surprisingly effective in urging measures such as: adjusting schedules for the use of electricity-intensive equipment and industrial processes; switching off office equipment, or enabling them to "sleep" in lower power mode; re-setting thermostats; and switching off non-essential lighting; and
- rationing, which can be supplemented by trading entitlements.

Emergency Demand Reductions allowed by **t**he National Grid's Operational Code Six[71] - OC6 (which is an emergency process, designed to deal with immediate faults and system constraints or for occasions when unexpectedly there is insufficient supply to meet demand, and not for planned use) indicate the scale of possible mandated reductions, which can be enforced by disconnection (and to a limited extent by voltage control). OC6 allows the National Grid to require non-embedded customers (who draw power directly from the grid) and transmission operators to reduce demand in steps that go up to i) 20%, whether national warnings have been issued or not, and ii) 40% with the condition that National Grid shall, if possible, issue a high-level warning. In the event of breakdown or operating problems (due e.g. to frequency, voltage or thermal overloads), the code allows automatic (and also manual) disconnection up to 60% (40% in Scotland).

Annex SI2 1 Supply/demand correlations in a simple model of with high electrification of heat

The figures and Tables in this Annex have their own numbering

This Annex describes a study of correlations with the 20/80 solar wind mix advocated in the report and the possible impact of neglecting correlations on modelling storage in 2050. The model assumes that 2050 electricity demand can be approximated by

> 1988-2016 electricity demand + (1988-2016 demand for gas for space heating/3 + new sources of demand (charging EV, electrification of parts of industry) - efficiency savings, using i) DUKES[72] quarterly electricity demand data for 1988 -2016 (earlier years are harder to find, and not so relevant as electricity use is changing), and ii) as a proxy for gas for space heating, DUKES easily accessible quarterly data demand for heat: gas to heat (this is CHP and is small) + domestic + 'other' other use of gas (which is mostly for heat): the factor 1/3 represents the assumption that a large fraction of space heating will be provided by heat pumps with coefficients of performance $\leq$ 3. It is assumed that the last two terms will be constant (this is obviously not exactly true, e.g. use of cars is slightly higher in the summer than in the winter, and is not true hour-by-hour, but it is a probably a reasonable approximation for averages over periods of a week or more, so that weekends are averaged out).

A plot of the variable terms in this expression shows that they have changed slowly over the years; a fit was used to remove this underlying trend:

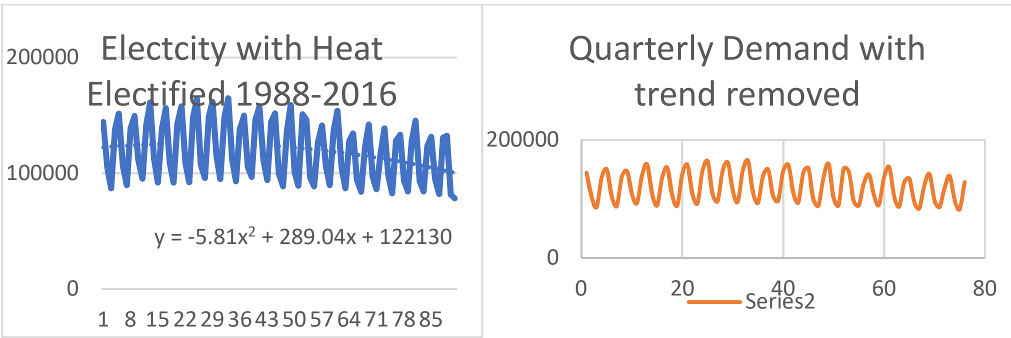


Figure 1: Model (described in the text) of demand with high electrification of heat. The numbers on the x-axis, which label the quarters in the 29 years studied, are the variables in the fit to the data.

The variable terms average 487 TWh/year. Adding the constant terms would bring the total to around the level considered in this report.

The following two plots show the deviations from the mean for i) supply, using the Ninja Renewable data, with the 80/20 wind/solar mix advocated in the report, scaled (somewhat arbitrarily) to an average of 695 TWh/year over the period considered[xii], and ii) demand according to the simple model described above.

[xii] Part will be lost because of storage inefficiencies. Some will be curtailed.

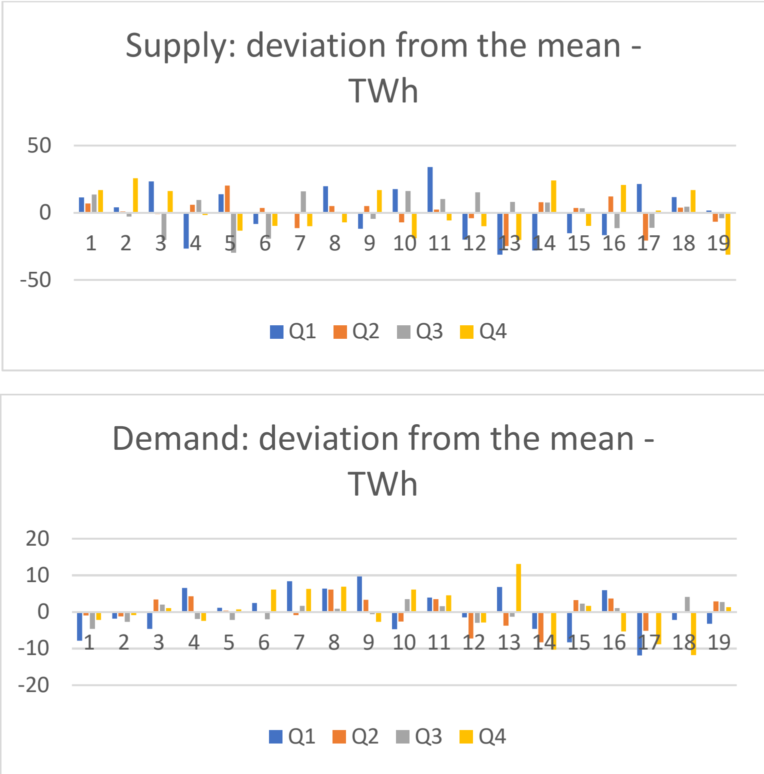


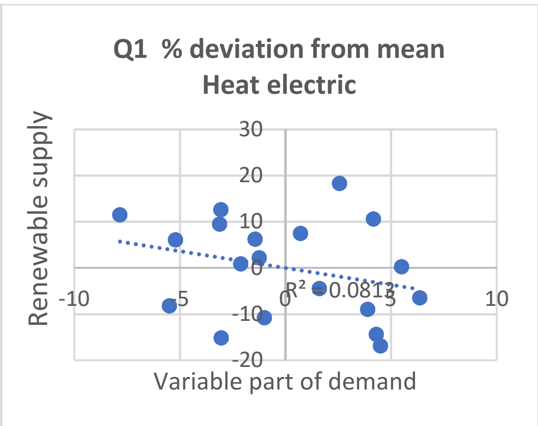
Figure 2: Deviations from the Mean supply and Demand in each quarter.

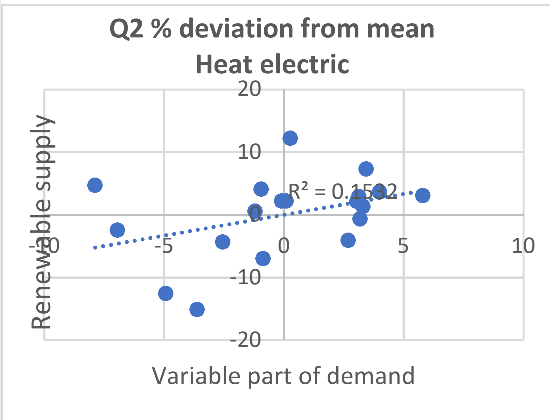
It is seen that that the fluctuations in supply (which range from roughly - 30 to + 30 TWh/quarter are much bigger than in demand (which range for -3 to + 4 TWh/quarter). This is true for the percentage as well as the absolute deviations from the mean, as shown in the following table, which also shows that (as expected) electrification of heat increases the variation in demand.

RMS of % deviation	Supply	Demand	
		Heat not Electric	Heat Electric
Q1	10.3	2.3	4.0
Q2	6.3	2.5	3.7
Q3	8.2	2.4	2.6
Q4	8.8	2.6	4.5

Table 1 Deviation from Mean Supply and Demand

The following plots show the correlations between deviations from the mean:





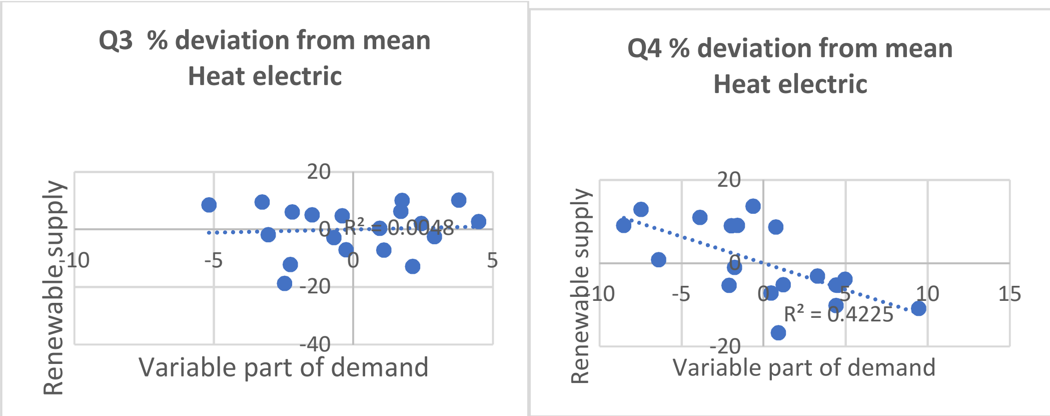


Figure 3: Correlations between deviations from the mean

It is seen that the correlation is non-existent/very weak in Q3/Q1, weak and positive in Q2 and significant and negative in Q4 - where the bottom right-hand quadrant includes periods when there are anti-cyclones and it is cold (so demand is high) and there is little wind (the opposite is true in the top left-hand quadrant). It is unclear why the correlation is so much stronger in Q4 then in Q1, and why it is positive in Q2.

The neglect of correlations would be expected to lead to an underestimate of the size of residual demand. This must be the case over the sort of periods during which wind droughts last. Slightly surprisingly, however, it seems not to be an issue for averages over a quarter. This can be seen by looking at the spectrum of residual demand using the above crude model with electrified heat and i) comparing supply and demand quarter by quarter (blue curve below) and ii) comparing supply in a given quarter with demand in the same quarter in year 1, i.e. by repeating year one, as done using the AFRY model in modelling in this report (orange curve):

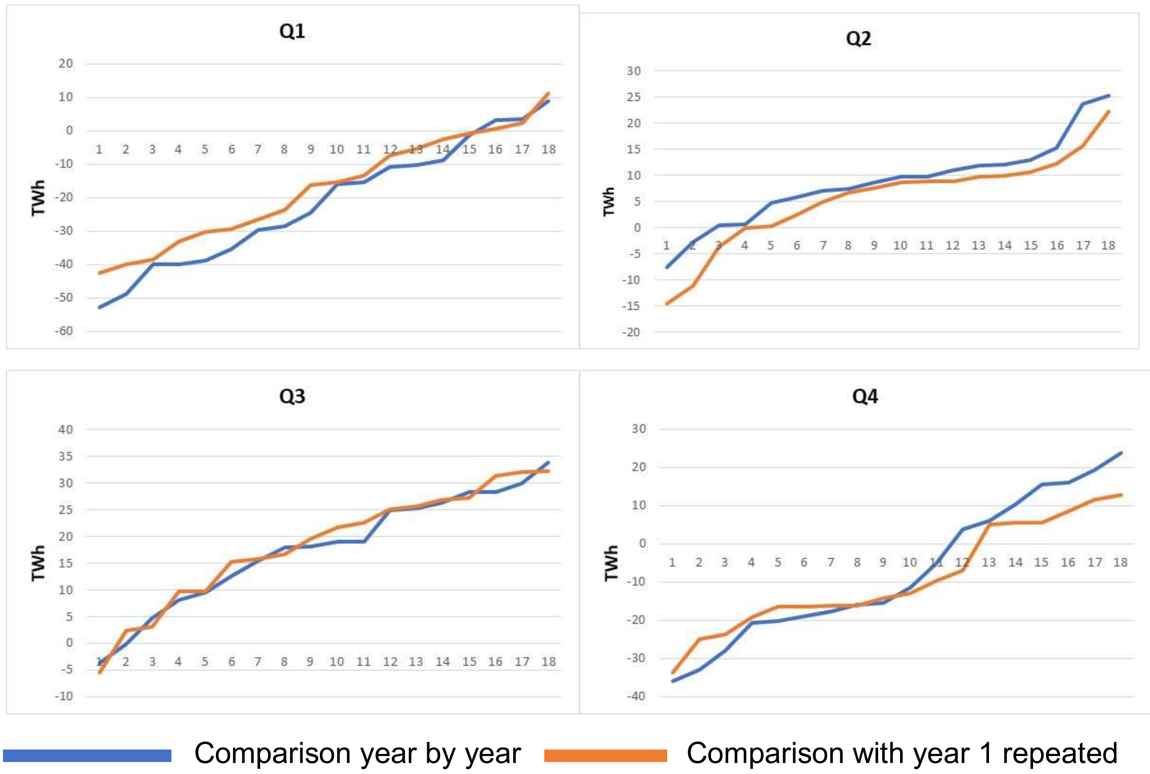


Figure 4 Ordered surpluses/deficits (largest deficit/surplus on the left/right) in each quarter over 19 years. found by i) comparing models of supply and demand in the same years (blue curve) and ii) comparing models of supply with demand in year 1.

It is seen that neglecting correlations has only a limited effect on the spectra of residual demand in each quarter, although (except in Q3) it increases their range.

Over longer long periods the correlations between supply and demand wash out:

For averages over one year[xiii] – demand is moderately (R^2 = 0.185) negatively correlated with supply

For averages over two successive years – the correlation is weak (R^2 = 0.0141) and negative

For averages over three successive years – the correlation is negligible (R^2 = 0.0052), and for what it's worth still negative.

For quantities that are only sensitive to behaviour over very long periods, it is therefore presumably safe to neglect correlations. These are

- The choice of the wind/solar mix (which takes account of all 37 years of data)
- The need for storage on a decadal time scale.

On shorter time scales, neglecting correlations presumably leads to underestimates of the size of the surpluses and deficits. This will have some impact on the size of the stores found by modelling, although with a hydrogen store available as a backstop it is hard to say how big the effect will be. In any case:

- It is not possible to examine very short-term behaviour as the model has a minimum resolution of an hour.
- Although their potential impact is discussed in the report, demand side responses which will play a role on short to intermediate time scales are not analysed.
- The analysis if fraught with uncertainties, related to the impact of climate change on demand as well as supply, the level of insulation in 2050, the degree of electrification of heat, neglect of increased demand for cooling etc.

The main conclusions of this analysis are that:

- While it would be interesting to carry out a similar analysis to that described here that looks at shorter periods (months or better weeks, if not days), it is currently very hard to imagine building demand/weather correlations into models reliably.

  Quantitative conclusions on short/intermediate-term storage should be treated with some caution, but neglecting correlations is probably a good first approximation in studying long-term storage.

[xiii] This is years running from April to March, rather than calendar years which mix different winters.

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ENERGY INSTITUTE

Annex SI 2 2

Preliminary estimation of long-term storage needs in a system with electrified demands and 100% wind and solar electricity supply

A note for the Royal Society long term storage project

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FIGURES

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Introduction

This note was written at the request of the Royal Society storage project leaders and is more of a working document than a formal academic paper. The note describes modelling, mostly conducted 2017-2018, aimed at initially exploring the impact of long-term meteorology data on energy demands and renewable supply (here wind and solar), and thence on the need for energy storage. The note first introduces the issue, a simple energy system, and storage theory and meteorology. Then a simple model is applied to this simple system. Simulation results are given and discussed. Finally, more complex modelling - a simple model has 100s of lines of code as compared 1000s of lines- by the authors of more realistic systems is introduced, such as is required to resolve some of the limitations of the simple energy system and model. In particular, this more complex modelling includes interconnector trade which reduces storage need substantially.

A key problem faced by any energy system is to match variable demands and supplies at different locations hour by hour across the year. While fossil fuels dominate the energy supply mix, meeting variable demands is relatively straightforward because fossil fuels are stored energy. A more demanding problem for future UK low emission energy systems is to match variable demands and supplies over periods ranging from seconds to years, particularly where supply is dominated by renewables without integral storage such as solar and wind, or inflexible nuclear. For the Royal Society storage project, we are concerned with energy storage needed to accommodate long term (weeks to years) demand and renewable variations. There are three non-exclusive options for managing energy surpluses and deficits arising from variable renewable and inflexible nuclear generation:

1. Storage of primary energy (biomass, geothermal, etc.), secondary energy (heat, cool, electricity, hydrogen, ammonia, etc.), or services (washed dishes, etc.) and products (e.g. iron).
2. Trade over long distance transmission lines to average demands and renewable outputs by dynamically exchanging local surpluses and deficits.
3. Deployment of increased renewable capacity enabling demands to be met at lower levels of incident resource (wind, solar radiation), but with increased renewable energy spillage and lower capacity factors.

In general, increasing one of these options allows a reduction one or two of the others. An objective is to find good designs with near optimal, least cost combination of these options such that constraints such as greenhouse gas emission targets are met - this is difficult to do and is not attempted here, but is in a forthcoming paper by Gallo Cassarino and Barrett (T. Gallo Cassarino & Barrett, 2021). In this note, a simple model is used to start to explore the magnitude and drivers of energy flows and storage needs. There is no cost analysis here.

1 Energy systems

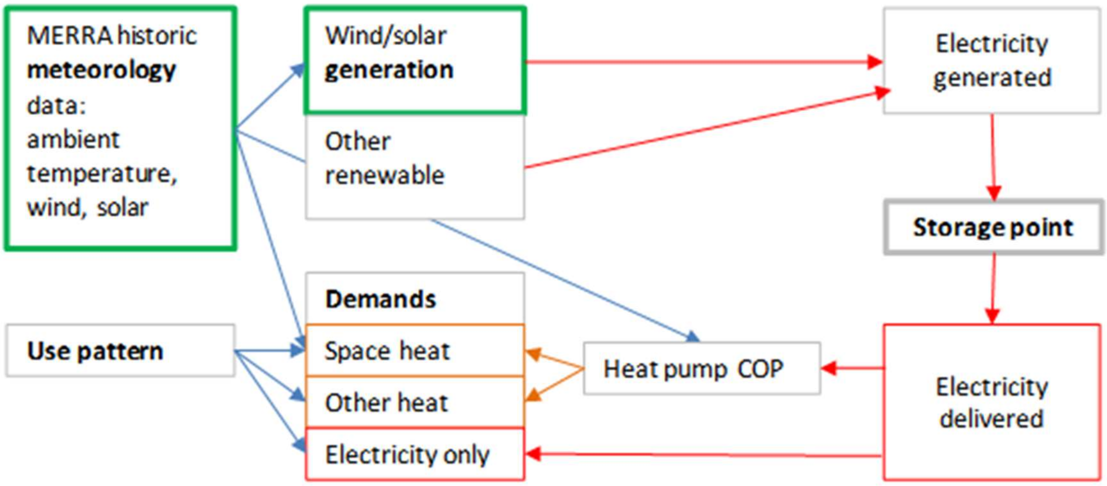
Energy service demands are connected to primary supplies through intermediate conversion, transmission and storage systems which can utilize multiple primary resources – fossil and nuclear fuels and renewables – and multiple vectors for their transmission – gas, liquid, solid, electricity and heat. The difference, or net flow, at any point between upstream and downstream flows may be positive or negative and it can be cumulated over any time period to determine the minimum storage needed to balance flows at that point.

This note focuses on the modelling of a simplified energy system, shown in Figure 1, with the system point where storage need is calculated. The analysis here is exploratory and so the remainder of the energy system is particularly limited and simplified in the following ways:

- The system demands are for electricity and heat services only in a single ‘sector’ and all services are powered with delivered electricity.
- Supply is UK sourced renewable electricity, solely from variable wind and solar which have no integral storage, unlike biomass, hydro, geothermal and so on.
- Trade between the UK and other countries is not included.

This is a demand and supply system that is challenging to design, having variable, weather driven all electric heating and variable wind and solar with no integral storage, and which therefore may engender an extreme storage requirement in terms of magnitude.

Figure 1 : Simplified energy system diagram

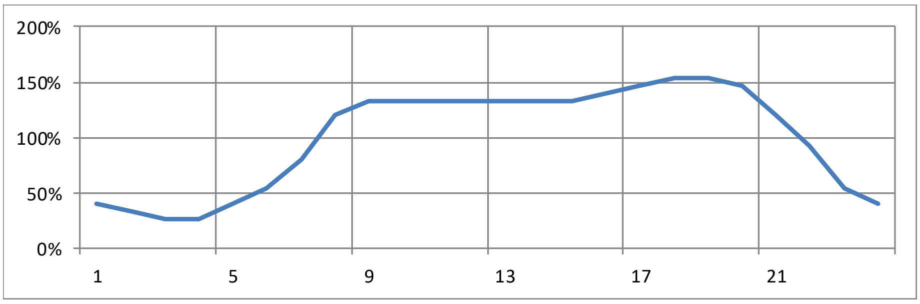


The most complex and separate part of the modelling in this note is collating meteorology data, weighting it by population and wind farm locations, and estimating wind and solar generation at different wind farm sites given factors such as wind shear and wind turbine efficiency functions. Social temporal activity patterns are fundamental drivers of demand variation, and meteorology also drives variations in the demands for space heating and cooling in buildings and vehicles, and in heat pump efficiency. Meteorology also determines the wind and solar resources. A historic data set of meteorology called MERRA (Modern-Era Retrospective analysis for Research and Applications) – see Rienecker et al (Rienecker et al., 2011) - has been used to drive demand and renewables and is described in more detail below.

The simple energy system consists of service demands and generation. There are just three demands: general electricity services (equipment, lighting, refrigeration etc.), non-space heat demand and space heat demand. Electric vehicles are not separately modelled and are included in general services, but in reality they have weather independent demands (propulsion energy is nearly weather independent), and weather dependent heating and cooling demands like buildings, which will vary with ambient conditions. Air conditioning demand is not included here: it is currently small compared to heat in the UK but future climate change will alter this balance. ‘By 2070, in the high emission scenario, this range amounts to 0.9 °C to 5.4 °C in summer, and 0.7 °C to 4.2 °C in winter’(Met Office, 2019).

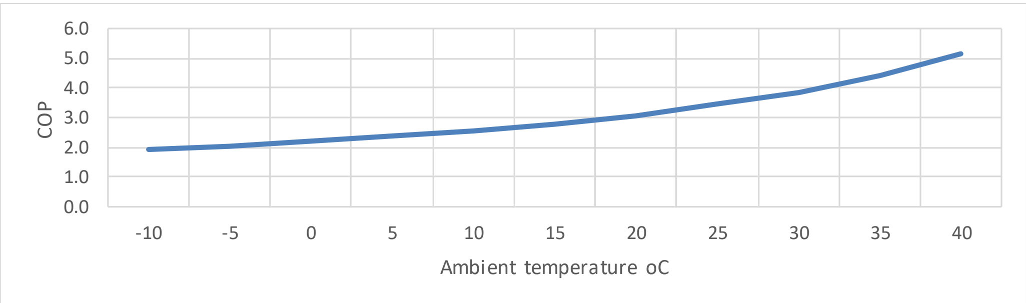
All demands are assumed to vary with a normalised diurnal use pattern (Use) shown in Figure 2, the shape of which based on previous work (T. Gallo Cassarino, Sharp, & Barrett, 2018). Space heat demand varies with ambient temperature, and also local solar radiation causing solar gain (not included here), and local wind speed which increases building heat exchange rates through altering ventilation rates and envelop skin resistance. Therefore, in general, net space heat demand is negatively correlated with solar radiation and generation, and positively correlated with wind speed and wind generation as local wind speeds are generally but not precisely correlated with wind speeds at wind farms. Use patterns vary with sector and subsector and will change in the future, but for long term, rather than diurnal, storage needs the pattern is not too critical for the simple modelling presented here.

Figure 2 : Normalised energy demand pattern - Use



Space and non-space heat demands are summed and met with an electric heat pump. In real systems, a range of heat pumps utilising different low temperature heat sources and designs will be used with a range of coefficients of performance (COP): in consumer systems a seasonal weighted COP typically ranges 2-3; and in district heating (DH) systems COPs range 3-5. District heat pumps (DH HPs) have a higher COP than consumer HPs partly because larger machines are more efficient, and partly because DH HPs can used higher winter temperature heat sources such a river, the ground or sewage. The heat pump here is assumed to be a consumer air source heat pump with a COP varying with ambient temperature as shown in Figure 3: the equation is a simply the Carnot efficiency multiplied by a constant 0.45. The assumed COP curve is critical to the electricity consumed for both annually and at peak times – if half of heat were supplied by DH HPs rather than all consumer HPs, the consumption of electricity for heat would be reduced by about 25% and the seasonal variation would be reduced because of the higher temperature winter heat sources generally available to DH heat pumps.

Figure 3 : Heat pump COP



The consumption of electricity for general services and for heating are summed to give total electricity demand. At ambient temperatures above about 20-25 ^{o}C space heat demand would be zero and the heat output would be for hot water or some other low temperature heat service.

The modelling is of hourly demands and wind and solar generation as driven by historic meteorology over a period of 31 years, in order to make preliminary estimates of the magnitude of differences between cumulative energy demand and variable renewables. These differences are a critical input to determining what is required to balance demand and supply with some mix of storage, transmission and renewables.

Table 1 shows the principal model variables. The energy system is defined by just seven variable values as shown in bold. As discussed below, the demand inputs might roughly represent a future UK with an annual electricity demand of about 700 TWh. Generation comprises onshore wind, offshore wind and solar photovoltaic which generate according to MERRA wind and solar resources.

Table 1 : Model variables and energy system definition

Variables	Code variable		Units	Comment
Ambient temperature	Tamb_oC	MERRA	oC	Population weighted
Wind speed at demand	WindDem_mps	MERRA	m/s	Population weighted
Solar radiation	Solar_Wpm2	MERRA	W/m2	Population weighted
Onshore wind factor	WindPowOn_Prop	MERRA	%	Wind farm weighted
Offshore wind factor	WindPowOff_Prop	MERRA	%	Wind farm weighted
Normalised activity pattern	Use(h)		%	System definition
internal building temperature	Tint_oC	**17**	oC	System definition
Average non heat electricity demand	DemNonHeatAv_GW	**60**	GW	System definition
Average non space heat demand	DemNonSpHeatAv_GW	**18**	GW	System definition
Specific heat loss	SpHeaLos_GWpoC	**5**	GW/oC	System definition
Wind capacity: onshore	WindCapOn_GW	**40**	GW	System definition
Wind capacity: offshore	WindCapOff_GW	**120**	GW	System definition
Solar PV capacity	SolCap_GW	**70**	GW	System definition

2 Theory overview

To estimate the storage need at a point in an energy system, the time varying flows either side of the point need to be calculated. In some cases, energy can flow either way across the point: for example, electricity might flow through a distribution transformer to consumers at night, but flow the other way when consumer solar PV generation is greater than local consumer demand. The storage flows may be of different types and in such cases the flow may be in one direction only: for example, upstream might be electricity input to a heat pump putting heat into a heat store for later output as heat to heat demand. The outputs of some stores are determined by the demands they meet, such as the output of an electric vehicle battery, and so cannot be controlled arbitrarily. Some storage, such as passive heat storage in building fabric, operates in complex ways and its inputs and outputs cannot be easily controlled. Some storage is not available all the time, e.g. space heat storage is only operational in the winter. Stores may have multiple inputs and outputs with different efficiencies. For example, energy stored as ammonia or hydrogen might fuel a CHP plant producing electricity at 35% and heat at 55% efficiency. Some storage is not for energy itself yet can help manage energy systems; for example, electric water pumping in the water industry can be flexibly scheduled using water storage in reservoirs.

2.1 Simple modelling

In the simple energy system and modelling, the assumption is of unidirectional hourly (h) flow of electricity from generation G(h) (GW) to demand D(h) (GW). The gross accumulated difference in energy Cgr (GWh) between G and D may be accumulated over some period:

$$\text{Cgr} = \sum_{h}(\mathrm{G(h)} - \mathrm{D(h)}) \qquad \text{GWh} \qquad [1]$$

- If Cgr is positive, then there is surplus of G over D and Cgr can be stored to the limit of available storage capacity.
- If Cgr is negative, then it is necessary to start the period with energy Cgr in the store to prevent the storage level falling below zero.

Minimum storage requirements are equal to Cgr assuming the store is 100% efficient, which is not the case for any real storage technology.

2.2 More detail

In general, stores have three processes: input, storage across time, and output, each with losses and power limits on input and output, and these need to be modelled to properly simulate storage; this is not done in the model used in this note but is in more refined models discussed in the final section. We need to account for the efficiencies of energy input to the store Eff_{in} and output Eff_{out}. The standing losses L(t) of the store will be some function of time depending on the store type, storage level, environment and so on.

Then for input to the store, the level of energy in the store Qst (TWh) changes from its initial level Qst_0 with input Q_{in}:

$$Qst = Qst_0 + Q_{in}\ Eff_{in} \qquad \text{GWh} \qquad [2]$$

Input loss is: $Q_{in}\ (1 – Eff_{in})$ GWh [3]

Standing loss L(t) over some time t is the integral of some, generally complex, energy loss function, so the storage level Qst after t is given by:

$$Qst = Qst_0 – L(t) \qquad \text{GWh} \qquad [4]$$

After storage useful output Q_{out}, the new Qst is:

$$Qst = Qst_0 - Q_{out} / Eff_{out} \qquad \text{GWh} \qquad [5]$$

Output loss is: $Q_{out}\ (1 – Eff_{out})$ GWh [6]

These processes must be tracked hour by hour over the whole simulation period; initial and final storage levels alone are not adequate: a store level may be the same at the end of a period as at the beginning but may have been discharged and charged multiple times within the period with Eff_{in} and Eff_{out} losses each time, plus any standing losses L(t).

In general, storage efficiencies Eff_{in} and Eff_{out} are variable and can depend on input and output power, store level, store and ambient temperatures, pressures, battery cycles, and so on. The standing losses of a store are also variable: sensible heat storage will lose heat at a rate approximately proportional to the difference between store and ambient temperatures; most batteries lose energy slowly with time depending on conditions and technology. Storage losses may appear as heat and in some cases this may be useful: for example, the waste heat generated by battery charge/discharge might take place at a district energy hub and the waste heat used in district heating.

Stores may be characterised by energy inputs and outputs of different forms with associated charge and discharge efficiencies. For example:

i. **Electricity in/electricity out.** 1 GWh of electricity output can be stored by inputting 1.2 GWh of electricity into an 80% efficient throughput battery; a useful output to input ratio of 0.8:1.
ii. **Electricity in/electricity out.** 1 GWh of electricity output can be stored by inputting 2.2 GWh of electricity into a 75% efficient electrolyser to produce 1.7 GWh of stored hydrogen which, assuming no storage losses, can later be output from store into a 60% efficient generator (e.g. a fuel cell) to produce 1 GWh. The overall useful output to input ratio is 0.45:1.
iii. **Primary chemical in/electricity out –** this cannot store surplus electricity**.** 1 GWh of electricity output can be 'stored' by storing 2 GWh of biomass for input to a 50% efficient power station; a useful output to 'input' ratio of 0.5:1.

iv. **Electricity in/heat out** - this can absorb electricity but outputs heat**.** 2 GWh of heat produced by a heat pump with a COP of 2 can 'store' 1 GWh of electricity; a useful output to input ratio of 2:1.

Additionally, stores in general have limits on the maximum input and output power capacities and the rates at which these can change. For example, grid batteries may have an energy stored (MWh) to power (MW) ratio of 4:1 – enough energy for maximum output for 4 hours. These technology characteristics critically affect storage type selection and sizing for different points in the energy system. It should be noted that real systems will have many stores of the same type (batteries, etc.) and these will not have the same characteristics in terms of capacity and efficiency, Further, these will not all become full or empty at the same time unless this is explicitly controlled centrally: therefore the aggregate power input or output of many stores will fall as the stores become full or empty one by one; unlike a single aggregate store which has maximum power until full or empty. This is a complex modelling challenge.

In this scoping analysis specific storage technologies are not modelled, and the results are therefore to be seen as order of magnitude calculations for the simple, renewable, electricity only system with no transmission trading.

3 Meteorology and wind and solar generation

The meteorology data used here consists of MERRA hourly reanalysis data for the 31 year period 1980 to 2010 which is available for the world at a spatial resolution of ½° latitude by ⅝° longitude (Rienecker et al., 2011). Ambient temperature, and wind and solar data were collated for the UK and surrounding waters and renewable generation is calculated with a complex suite of algorithms written in python by Sharp (T. Gallo Cassarino et al., 2018).

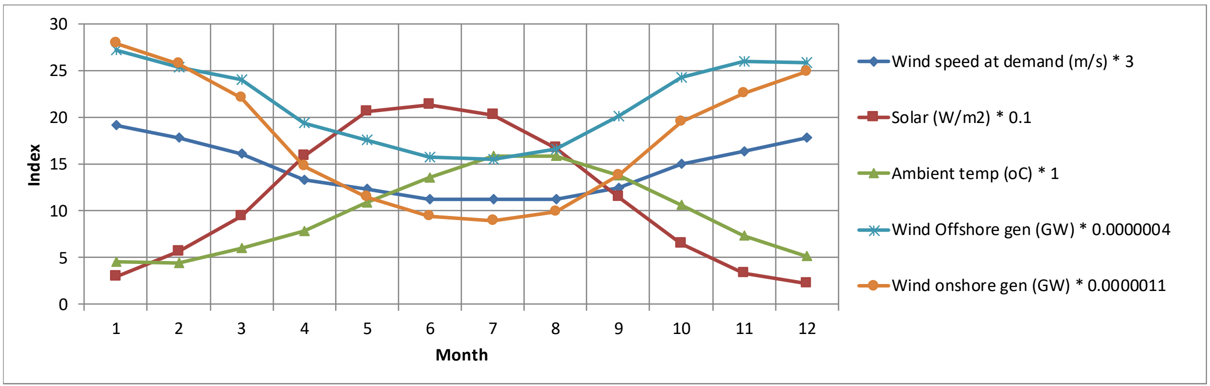
The MERRA data used are for ambient temperature in degrees Centigrade (model variable Tamb_oC) and ground level wind speed in metres per second (WindDem_mps) which both drive space heat demand - air conditioning is not modelled here. Global solar radiation is in Watts per square metre (Solar_Wpm2) and drives solar photovoltaic generation – the impact of solar gain on building heating and cooling is not modelled here. It is assumed that solar collectors will be near population, and so Solar_Wpm2 and the demand driving variables (Tamb_oC, WindDem_mps) are all weighted by the UK population spatial distribution by km^2; this processing by Sharp.

Hourly MERRA wind speeds are collated for UK onshore and offshore wind farm locations. These are then processed accounting for wind turbine height and wind speed power curves to produce normalised hourly output, GW output per GW installed for each wind farm location. These farm outputs are then weighted to produce total hourly percentage of installed capacity factors for the set of onshore (WindPowOn_pcCap) and offshore farms (WindPowOff_pcCap).

Climate change will increase ambient temperatures, as is notable in the MERRA data from 1980 to 2010, and consequently decrease space heat demand, increase air conditioning demand, and increase heat pump COP. To simply reflect climate change, additions of 2 °C and 4 °C to MERRA temperature data were modelled with ESTIMO (T. Gallo Cassarino & Barrett, 2021), with the result that annual space heat was reduced by 22% (2 °C) and 41% (4 °C) respectively and annual total heat by 13% and 25%; electricity for heat pumps is reduced by more than this because of a higher COP. Furthermore the seasonal variation and peaks of heat demands are also reduced, easing long term storage needs. Climate change will also have impacts on renewable generation through modifying wind speeds, and solar radiation because of atmospheric absorption and reflection, and because photovoltaic efficiency is affected by temperature. Solaun et al (Solaun & Cerdá, 2019) review research into these impacts, reporting both small positive and negative changes to generation with geographical variations, so there is no clear overall impact and the consensus seems to be the change in generation will be small.

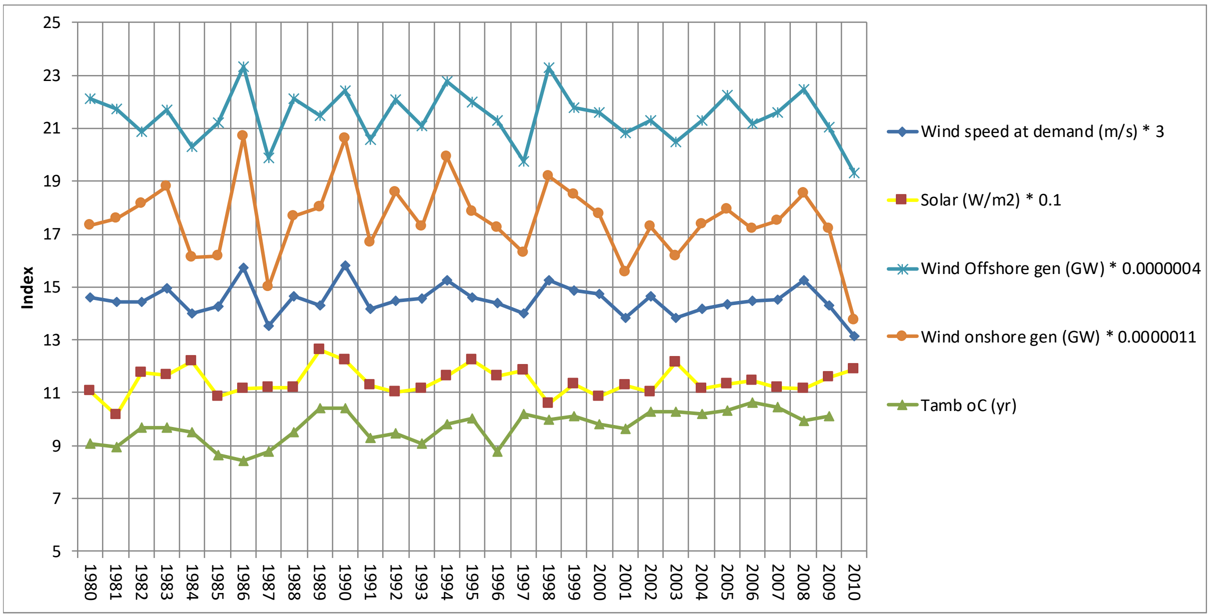
Figure 4 shows monthly averages over 31 years of meteorology and renewable generation; the variables are scaled so as to show them on one chart. Wind speed at demand is the wind speed at ground level assumed to affect building heat exchange through air change rate and other processes and this leads to some positive correlation between heat demand and wind generation. Wind is on average highest in winter, and solar in summer. Solar is primarily driven by celestial mechanics, so it peaks in June, and the ambient temperature lags solar because the earth takes time to warm up to a maximum in July and August and then cool. These variables are the main drivers of long-term changes in demand and wind and solar supply, and therefore of long term storage needs in the system modelled here.

Figure 4 : Monthly average scaled meteorology and renewable generation



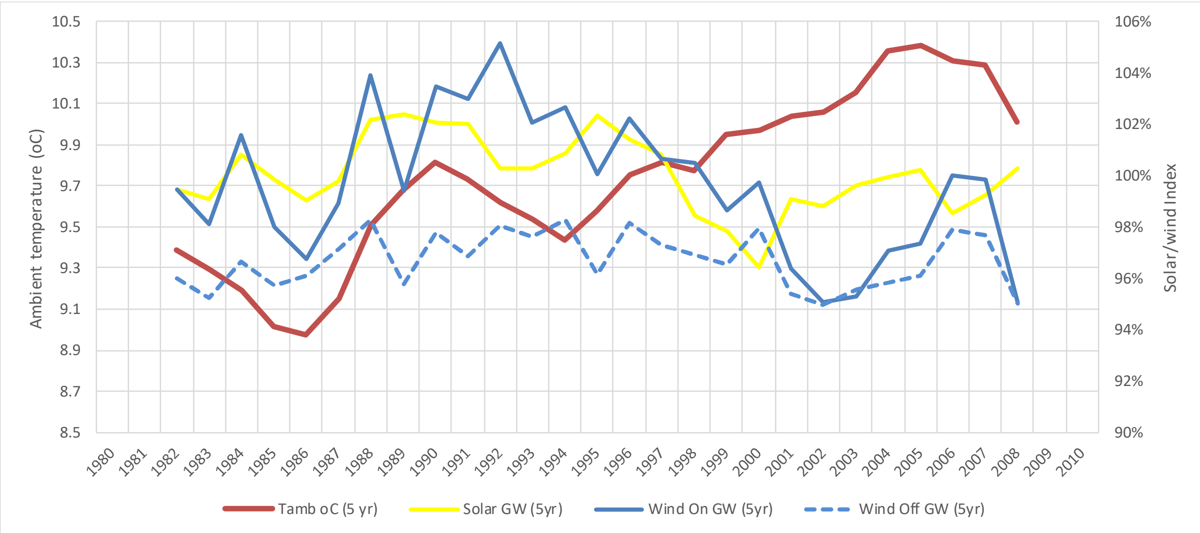
The annual average meteorology and wind power for the 31 years are shown in Figure 5; the variables are again differently scaled to show all the variables on one chart. [Demand wind speed (m/s) is the wind speed at demand WindDem_mps]. We see, for example, that 1986 had a low ambient temperature but high wind output, whereas 2010 had low temperature and low wind so *prima facie* might be a stress year with high space demand and low wind generation. However, note that annual average or total data are not necessarily revealing - the low temperature and low wind might be in summer when demand is generally low and solar high.

Figure 5 : Annual average scaled meteorology and renewable generation trends



To clarify meteorological trends, 5 year running averages of ambient temperature, solar and wind generation are shown in Figure 6. Annual average ambient temperature (population weighted) increases over the period, with the average for the last ten years being 0.71 °C higher than for the first 10 years, which may be due in part to climate change. Solar intensity (population weighted) and on and offshore wind generation show less long term variation. Assuming no substantial changes to the seasonal patterns of these variables, it may be expected that the trend will be for space heating needs to reduce across the years, but for generation to change little.

Figure 6 : Five year rolling average meteorology and renewable generation trends



	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Tamb oC (5 yr)			9.4	9.3	9.2	9.0	9.0	9.1	9.5	9.7	9.8	9.7	9.6	9.5	9.4	9.6
Solar GW (5yr)			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind On GW (5yr)			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.0	1.0	1.0
Wind Off GW (5yr)			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2004	2004	2004	2004	2004	2005	2006	2007	2008	2009	2010
Tamb oC (5 yr)	9.8	9.8	9.8	10.0	10.0	10.0	10.1	10.2	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.3	10.3	10.0		
Solar GW (5yr)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0		
Wind On GW (5yr)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0		
Wind Off GW (5yr)	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0		

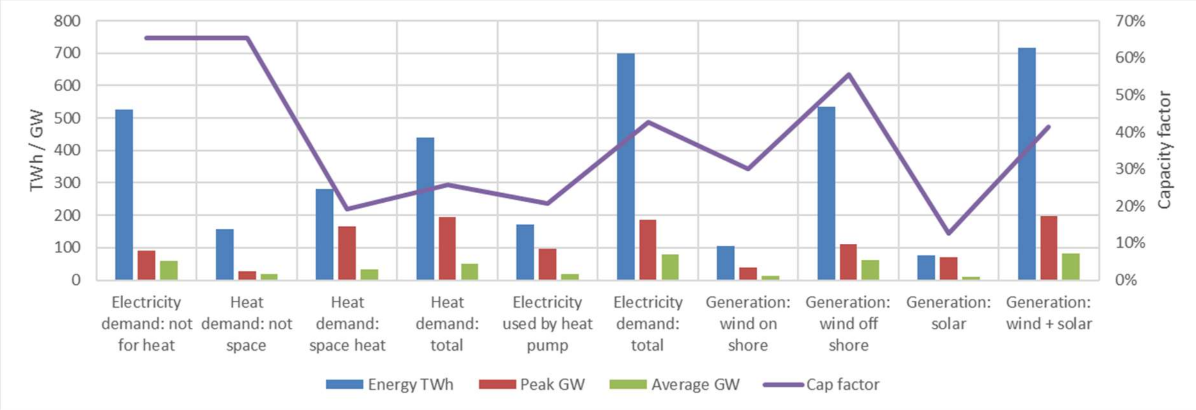
4 Simulation results

The simple model was used to simulate the system for each hour of 31 years (1980 to 2010) using hourly meteorology and renewable generation.

Figure 7 summarises the annual simulation results averaged over this period. The total heat demand is 439 TWh compared to the current approximate 450 TWh; this is supplied with heat pumps with an average weighted COP of 2.5 so that 173 TWh of electricity is used for heating. Total electricity demand averages 699 TWh which is about double 2018 UK consumption. There has been no attempt to correlate the demand and supply specification with any particular UK scenario because the model is not detailed, and system designs with net zero greenhouse gas emissions are not yet common and there are especial uncertainties concerning international transport fuel production and atmospheric carbon capture. But, for example, National Grid scenarios produced in 2019 (National Grid, 2019) have 2050 electricity demands ranging 300-400 TWh and gas demands 400-800 TWh. If these gas demands were mostly heating, they could be met with electric heat pumps at a COP of 2 with 200-400 TWh of electricity: this gives a total electricity demand ranging about 500-700 TWh. Wind and solar generation can be increased greatly and storage needs as a percentage of annual demand will not change very significantly as long as the proportionate mix of demands, renewables and intermediate conversion is maintained.

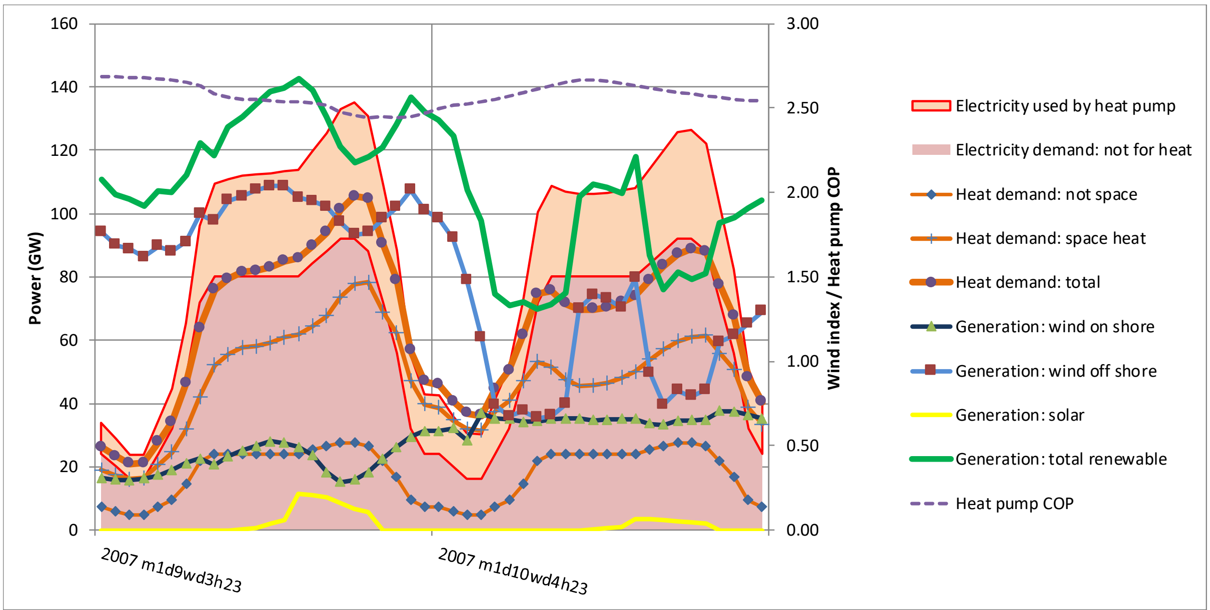
Figure 7 also shows the capacity factors, defined as average flow in the year divided by peak flow, for each annual flow. For example: the space heat demand capacity factor is just over 20%; total electricity demand just under 40%; solar generation about 13%, and offshore wind about 55%.

Figure 7 : Annual averages 1980 to 2010



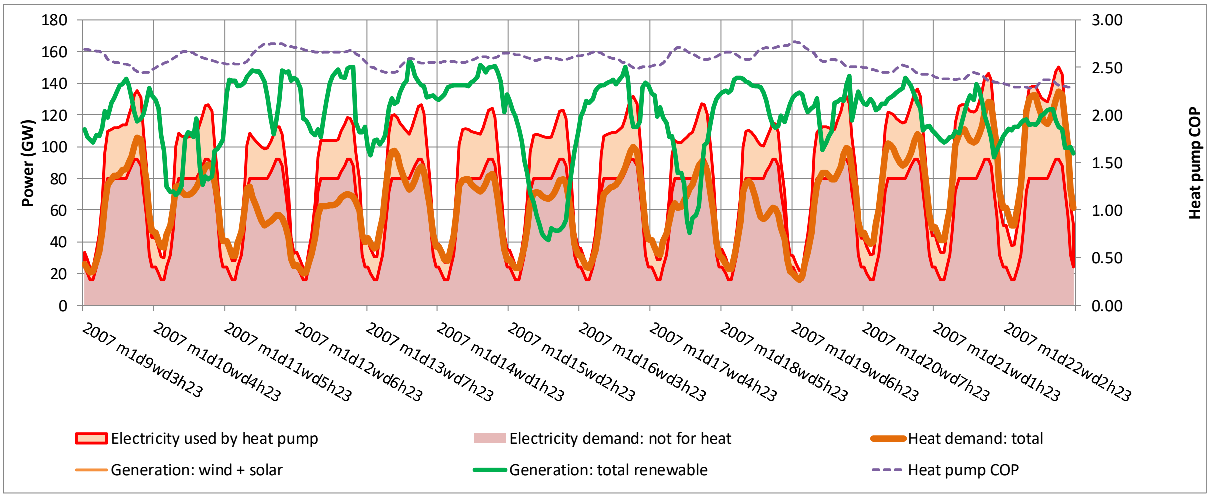
Figures 8 and 9 show randomly chosen simulation samples for 2 and 14 winter days in 2007 (the x-axis label code is Year Month DayOfMonth DayofWeek Hour). The energy flows and heat pump COP are for each hour, not accumulated. The electricity demand (delivered) for heat is the heat demand divided by the heat pump COP. As the ambient temperature falls, space heat increases and the heat pump COP decreases, and as electricity for heat equals heat demand divided by the COP, the electricity required for driving the heat pump is very sensitive to ambient temperature.

Figure 8 : Two days sample simulation – winter 2007



During the 14 winter days shown in Figure 9, the peak occurs during the last day at 17:00 hrs.: at this time the space heat load drives a peak total heat load of 135 GW met by 58 GW of electricity driving a heat pump with a COP of 2.3, the COP is near a minimum at this time. Adding 92 GW of electricity specific (non-heat) demand sums to a total electricity demand of 150 GW. In the second chart of Figure 9 the net surplus or deficit – total electricity demand-total generation is plotted for the 14 days. There is a deficit at the peak time, but it is not as large as on the 7th or 9th days. This illustrates that ambient temperature, driving space heat demand, is not tightly correlated with wind and solar generation on short time scales, though of course they are statistically related seasonally. As might be expected, the surplus mostly occurs during the night as demand is higher during the day and wind is fairly evenly spread across the day, and this is when smaller stores with a capacity of a few hours or days such as EV batteries and consumer heat stores could mostly be charged.

Figure 9 : Two weeks sample simulation – winter 2007



The operation of the system in a summer fortnight of 2007 is quite different from that in winter, as shown in Figure 10. The heat demand is lower and the heat pump COP higher so electricity for heating is lower. Wind generation is lower but solar generation higher. In this selected fortnight, there is a general deficit of generation. This might suggest more solar capacity is advantageous.

Figure 10 : Two weeks sample simulation – summer 2007

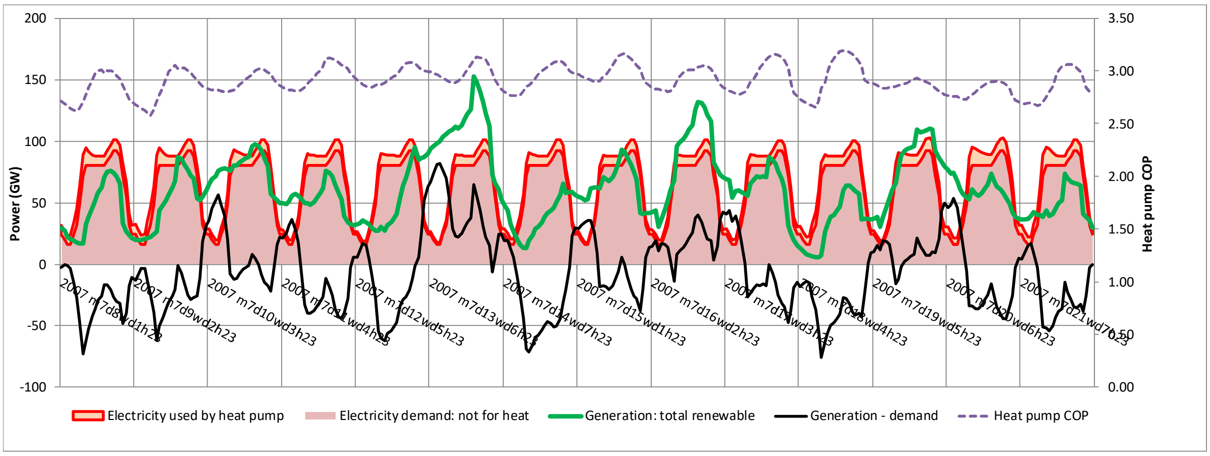
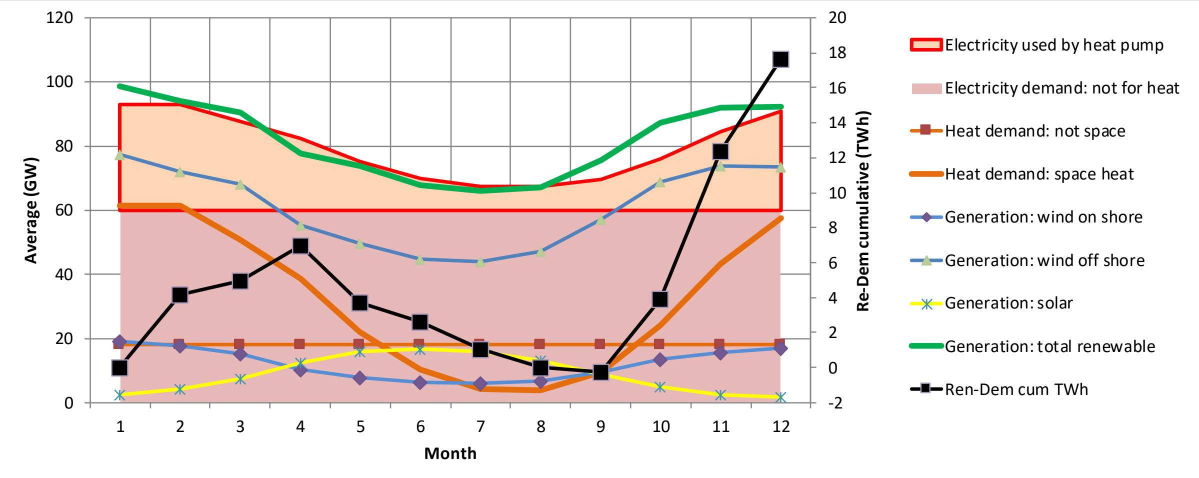


Figure 11 shows the average monthly flows and cumulative levels. On average there is a cumulative surplus at the end of the year. Of note is that the surplus falls from month 4 to reach a minimum in month 9. This indicates that for this simple, illustrative system, solar generation might be increased relative to wind to maintain the surplus in summer.

Figure 11 : Average monthly flows 1980-2010



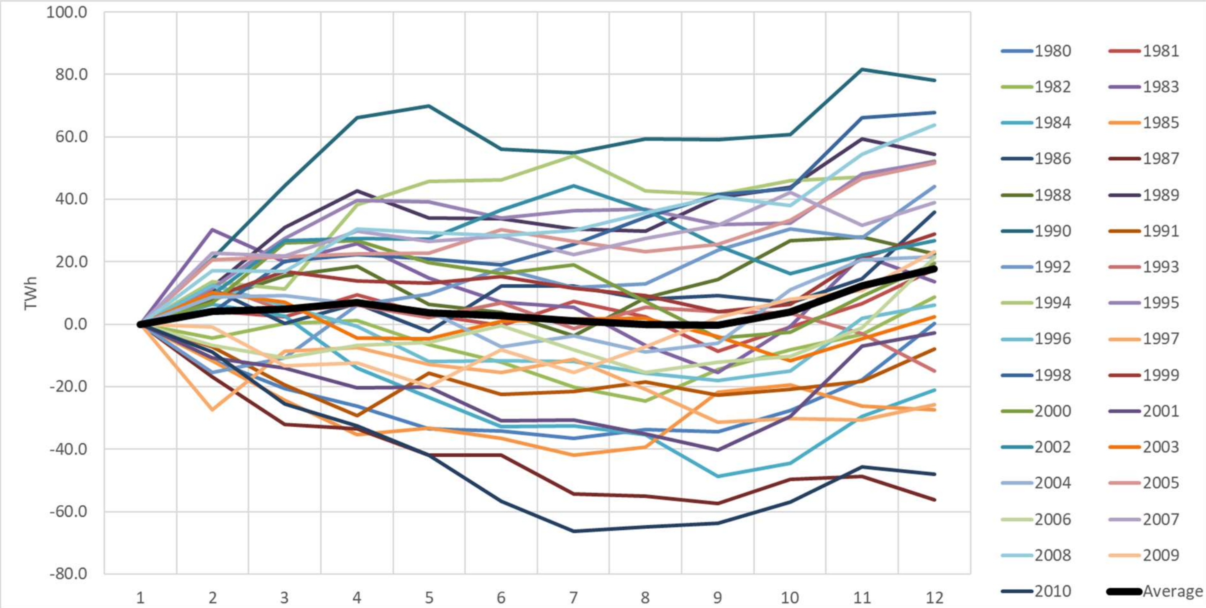
The curves of cumulative net difference (renewables-demand) for each month and the years 1980-2010 are shown in Figure 12 below. The simulation starts on January 1st each year; starting at a different time would not ultimately affect the cumulative difference over years and the consequent storage needs. It is not possible to clearly label the curves with a year; the point is to show that some years have surpluses and some deficits, and to show the average pattern of cumulative difference across all years.

Where the cumulative difference is negative at the year's end, there is excess demand in the year; in those years energy is needed 'in store' at the beginning of the year to avoid the cumulative residual demand falling below zero. Where the cumulative difference is positive there is a surplus of generation over demand, some of which might be stored. For the two extreme cases:

i. The minimum of these curves is -66 TWh in month 7 in 2010; therefore 66 TWh of stored electrical output would be required at the beginning of the year to meet this maximum deficit / minimum surplus.
ii. The maximum of these curves is 82 TWh in month 11 in 1990; therefore 82 TWh of electrical input storage capacity would be required at the beginning of the year to absorb this maximum surplus.

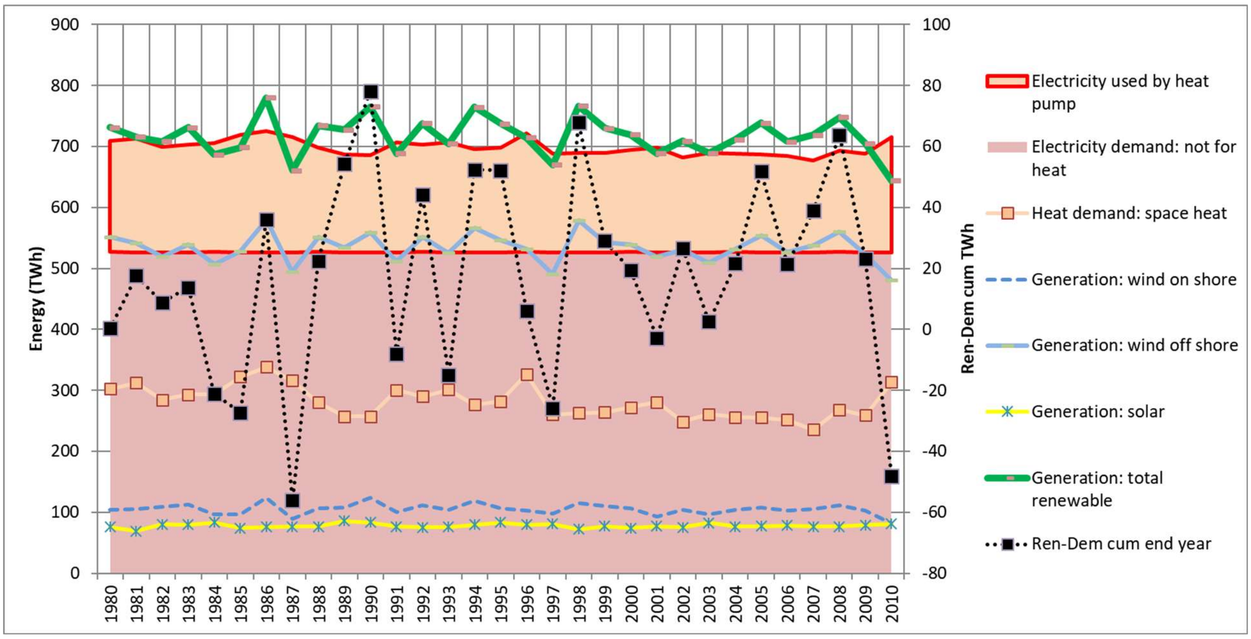
Because of the storage throughput inefficiency, there will be asymmetry between output and input which is not accounted for - cumulative difference is not the same as the actual storage technology capacity needs. The minimum calculated (i above) is the minimum stored energy at the beginning of the year needed to ensure demand is met, so this is critical. The maximum (ii above) is the storage required if no renewable spillage is to occur. The average monthly curve shows the average minimum to occur during August/September.

Figure 12 : Monthly cumulative renewables-demand - 1980 to 2010



The annual energy flows and cumulative (supply-demand) levels at the end of the year are shown in Figure 13. Wind provides the main year to year fluctuations in supply and offshore wind more than onshore wind. Space heating also varies as driven by changes in mean ambient temperature. It may be seen that a maximum cumulative difference ranges from about +/- 60 TWh, or +/- 10% of average annual demand. There is no immediately obvious correlation between sequential years in term of cumulative surplus.

Figure 13 : Annual results 1980 to 2010



The hourly difference (supply-demand) cumulated over 31 years, and the annual totals, are shown in Figure 14. There was no attempt to match overall supply and demand in each year. The supply system matches demand in 1980 and then responds to variations in wind, affecting supply and ambient temperature affecting demand, hour by hour and year by year. In this particular simulation, an initial energy ‘storage’ of 20 TWh is required in order that the cumulative surplus does not fall below zero across the whole period 1980-2010. The cumulative difference – excess supply over demand - increases particularly in the later years. This is because the average ambient temperature increases during this period, as noted in section 4, which decreases space heat demand and increases heat pump COP, and therefore reduces electricity used by the heat pumps. This results in a cumulative surplus over the period of 31 years of 600 TWh (with most of this arising 1990-2010), or 3% of average annual demand per year. However more detailed analysis is needed of the variations in demand and wind and solar across these years to be detail why the cumulative surplus supply increases. It may be assumed that global warming will further reduce space heat needs and increase the (currently smaller) air conditioning demand: and if wind and solar generation is not affected appreciably, then storage need will likely be reduced in this simple system. Extending the modelling using MERRA data before and after the period 1980-2010 would make conclusions about the long-term variation in temperature, demand and renewable generation more robust.

Figure 14 : Cumulative supply-demand 1980-2010

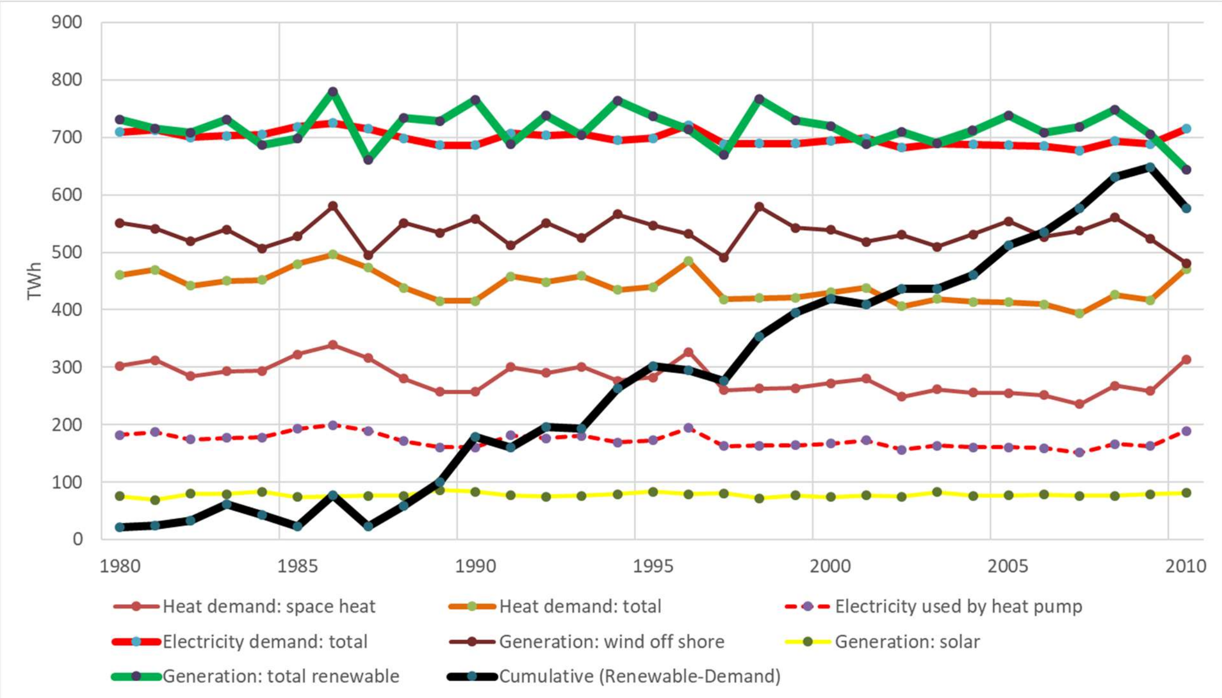
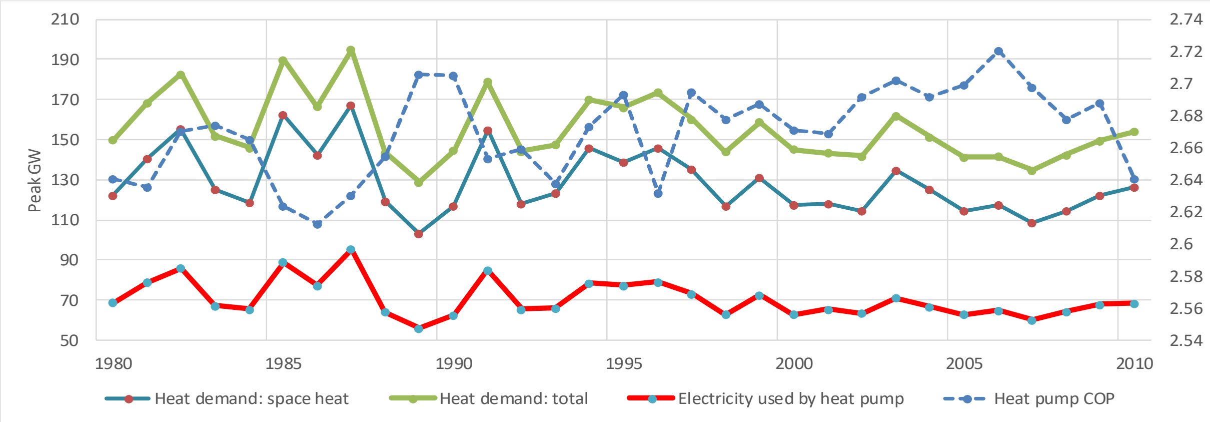


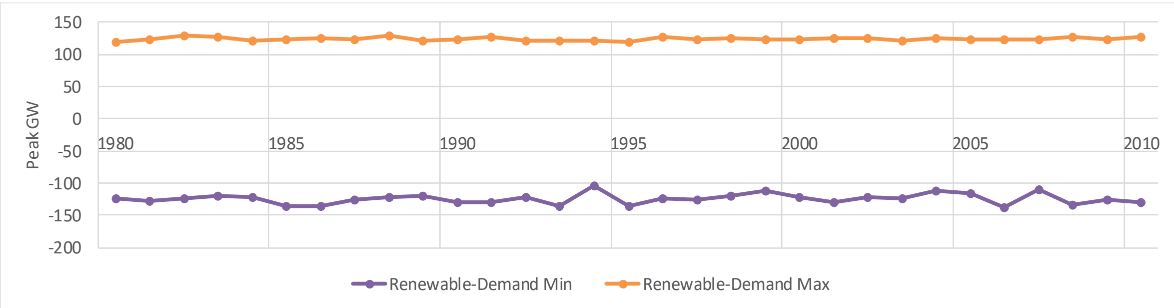
Figure 15 shows the peak heat demands and electricity supplied to heat pumps in each year 1980 to 2010. The peak flows in the system are important as they determine the installed power capacity requirements needed to ensure secure consumer services. For example, primary stores of biomass or gas input to generators of a capacity to meet peaks might be used when all other stores are exhausted. During this period, a reduction in the peak space heat and therefore total heat demand and heat pump electricity may be discerned: the average peaks in the period 2001-2010 are 12% less than in 1980-1989. It is also notable that the variation in peak from year to year gradually diminishes.

The second chart in Figure 15 shows the peak (in any hour of the year) surplus and maximum deficit (renewable – total electricity demand) in each year. These are generally in the range +125 GW peak surplus and -125 GW deficit. This gives a guide as to the maximum power capacities of storage input and output required. Note that stores of surplus, such as batteries or hydrogen, will not in general be the same as stores to meet deficit, such as biomass for input to CHP.

MERRA data for after 2010 are required to see if these trends continue.

Figure 15 : Peaks – heat, heat pump electricity, average COP, surplus and deficit





5 Discussion

The discussion is of the simple system and simple model results, and of what a more realistic energy system would look like, and how it can be modelled.

5.1 Simple system and modelling in this note

This modelling of a simple all electric demand and renewable supply system shows that both in-year and year to year demand and renewable variation pose a significant challenge for matching supply and demand, and thence for storage or trading. The modelling shows the variable nature of meteorology over all periods and therefore of demands and wind and solar renewable generation. More elaborate modelling will not remove this fundamental variability. It should be noted that energy production from some other renewables such as hydro and biocrops can vary significantly from year to year because of meteorology, notably precipitation and ambient temperature.

The modelling showed that the cumulative surplus increased little in the years 1980-1985 but thereafter generally increased: this is because of the increase in ambient temperature lowering space heat demand and increasing heat pump COP. It also showed that peak heat demands reduce over the period 1980-2010. It would be useful to extend the meteorological data set to before 1980 and after 2010. It should be noted that increasing solar and wind capacities such that they generate significantly more than demand and therefore more energy is spilled will reduce storage need; so also will international trade through interconnection. The optimal balance of overcapacity, storage and interconnection will depend on the relative costs of these.

Given the simplified all renewable electric energy system and the assumed system definition inputs, the model indicates that a minimum about 60 TWh of cumulative difference (‘storage’), or 10% of annual demand is needed at the start of the year to avoid a shortfall in the worst year. The maximum surplus of renewable generation in any hour across the years is about 125 GW, and coincidentally the maximum deficit is also about 125 GW. These gross results for cumulative energy and peak differences give approximate scope to the storage required. If the relative proportions of demands and renewables are not changed then the percentage of annual demand storage required will not change significantly because offshore wind and solar resources are very large and can be scaled up.

The cumulative differences calculated effectively reflect electricity storage with an efficiency of 100%. The actual technology capacity would have to account for the round-trip efficiency of input, standing losses and output from the store would need to be accounted for and addressed with the provision of additional capacity. For illustration: if the storage were biomass for input to a 50% efficient power station, then 60 / 0.5 = 120 TWh of biomass would be needed; if the biomass were input to district heating CHP with an overall efficiency of 80% (30% electrical plus 50% heat efficiency), assuming the heat and electricity outputs could be matched to demand, perhaps using district heat storage, then 60/0.8 = 75 TWh of biomass would be needed. For reference, assuming a calorific value of 17.5 GJ/t (Kofman, 2010), the wood pellet supply system to Drax power station includes 320 kt (1.6 TWh) of storage at the power station (DraxBiomass, 2020b) and 200 kt (1.0 TWh) at the Immingham dock (DraxBiomass, 2020a), to give a total 2.5 TWh of storage. This is of the order of 2%-4% of the total storage required in the simple system modelled here, though it is not suggested that this is the best use of biomass – it might be reserved for premium uses such as for aviation fuel synthesis.

The performance of some components will improve in the future and significantly impact storage needs. On the demand side, space heat depends on building efficiency and delivered electricity for that depends on the heat pump COP, especially at low temperatures: improvements to these would substantially impact on seasonal heat demand variation. The increasing size and offshore siting of wind turbines increases capacity factors. Over the period 2005 to 2018 aggregate offshore capacity factors have increased from about 30% to 40% (The Crown Estate, 2019). Currently (2020) the average offshore UK installed wind turbine is typically 3-5 MW capacity, but the largest wind turbine installed in 2020 is 12 MW (GERenewableEnergy, 2020), located at Rotterdam, for which the capacity factor is projected to be 63%. SiemensGamesa are producing a 14 MW turbine which should be ready for the market in 2024 (SiemensGamesa, 2020). A study for the UK (DNV-GL, 2019) projects offshore capacity factors of 50-60% by 2030. Designs for wind turbines of up to 50 MW are being developed, as reported by gtm (gtm, 2020), so it may be that factors higher than 60% are realised over the coming decades. The offshore wind modelled in this work has a capacity factor of about 55% averaged over 31 years and so might reasonably represent future factors. In general, higher capacity factors will mean less storage, but the exact impact depends on how the generation is distributed across the year relative to demands.

This simple model might be further applied with different assumptions about demand and renewable mix. On the demand side, the assumptions of building heat loss characteristics driving heat demand and heat pump performance are particularly important as these together strongly impact annual heat demand and electric heat consumption, and its seasonality. However, the model used is too simple and restricted to take the analysis further and reach detailed robust conclusions. The main limitations are that vectors and storage other than electricity and international electricity trade are not included, and neither are costs.

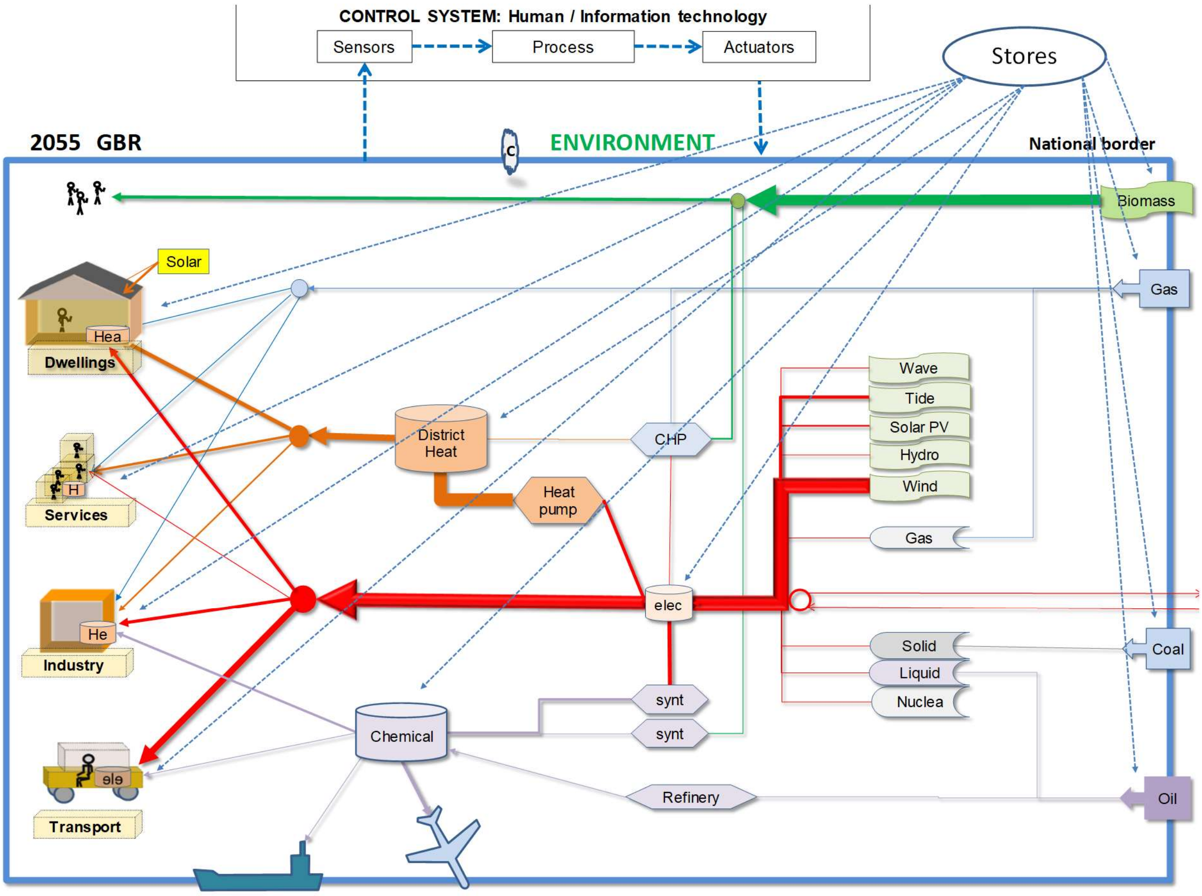
5.2 More realistic systems and modelling

A diagram of a more realistic energy system is shown in Figure 16 as taken from a DynEMo (Dynamic Energy Model) simulation for 2055 (see below and (Barrett & Spataru, 2016)). This represents a national energy system. It shows some of the points (13 in all) where storage of different kinds (chemical, electricity, heat) can be connected in the system to different vectors: at consumers, in intermediate systems such as electricity, district heating and synthetic fuel production, or as primary energy. Modelling needs to account for a full set of sectors, service demands, intermediate systems (synthetic fuels, district heating, etc.) and multiple storage types (heat, electricity, chemical, etc.) and sizes connected at different points in the energy system. Renewable heat (solar, geothermal) and other renewable electricity (hydro, geothermal) and biomass sources should be included. Hydro and biocrops are also strongly affected by meteorology; hydro is subject to large interannual variations.

Also shown in Figure 16 is a schematic of the control system. The engineering performance of stores and other individual technologies can be modelled accurately in isolation. However, it is harder to devise dynamic whole system control strategies which change the inputs and outputs of all the various stores and consequent flows across the national and international system hour by hour across the seasons so as to efficiently utilise renewables and other system technologies and thereby minimise operational costs and emissions. This system needs to be modelled in order to arrive at energy system operation combining the options of storage, transmission and renewable spillage, as set out in section 1, at low or least cost. This poses challenging questions, for example:

- If there is a surplus of renewable electricity, how should this be allocated to the different stores, such as to district or consumer heat pumps and stores, EV batteries, or hydrogen production?
- If there is a deficit, which stores should be used first – e.g. electricity from batteries or a biomass generator?
- Should some energy be retained in stores over long periods so as to meet maximum deficits during peak winter demands?
- How can meteorology short-term forecasts or long-term statistics be used for managing optimal operation over days or months?

Figure 16 : A more realistic energy system



The operation of this more realistic system has been simulated with the DynEMo model which includes control algorithms, as described in (Barrett & Spataru, 2013a), (Barrett & Spataru, 2013b) and (Barrett & Spataru, 2016). However, DynEMo is limited in two particular respects: a long-term meteorology data series is not used, and trade was not accounted for as this requires also concurrently simulating the countries or regions which the UK is connected to with transmission.

Building on DynEMo, these two deficiencies have been resolved with the ESTIMO (Energy Space Time Integrated Model Optimiser) model developed by Barrett and Cassarino. ESTIMO simultaneously simulates (hourly) each country or region within a trading bloc using MERRA data for each country. ESTIMO includes algorithms for storage management within a country and for trading surpluses and deficits between countries using storage where possible, within transmission constraints. Early analysis with ESTIMO (T. Gallo Cassarino et al., 2018) showed that electricity trade between the UK and other European countries might reduce European storage needs by about 30%.

Currently ESTIMO simultaneously simulates five regions: the UK, and regional aggregates of NW, NE, SW and SE Europe. ESTIMO has been applied to construct nine zero emission renewable systems with different electric and hydrogen heating shares showing, inter alia, the interdependence of required renewable, interconnector and storage capacities in providing system reliability; this is reported in a forthcoming paper (T. Gallo Cassarino & Barrett, 2021). The optimum balance between these capacities depends heavily on the relative costs of these. In the ESTIMO scenarios and in ancillary optimisation, 40-50% of the renewable electricity is spilled, as this is lower cost than increasing storage.

ESTIMO was used to explore the impact of climate change on demands and certain renewable supplies and thus be used to design robust 100% renewable systems for the UK and Europe. It was found that climate change reduces space heat demand by about the same amount as it increases space cooling demand: this changes the seasonality of electricity demand and will alter the optimum balance between wind and solar generation.

6 Addendum: Increased renewable capacity

This addendum explores the option to reduce storage need by increasing renewable generation. This will cause more renewable energy surplus which might be spilled or exported. In this system, called System 2, everything remains as before (called System 1), except that offshore wind capacity is increased from 120 GW, and solar from 70 GW. The System renewable capacities are shown in Table 2 for the three variants of System 2 (2.1, 2.2, 2.3). There is no economic justification for the capacity mix of System 2, or indeed System 1, and the optimal balance between generation, storage and interconnectors will ultimately mainly be determined by cost minimisation.

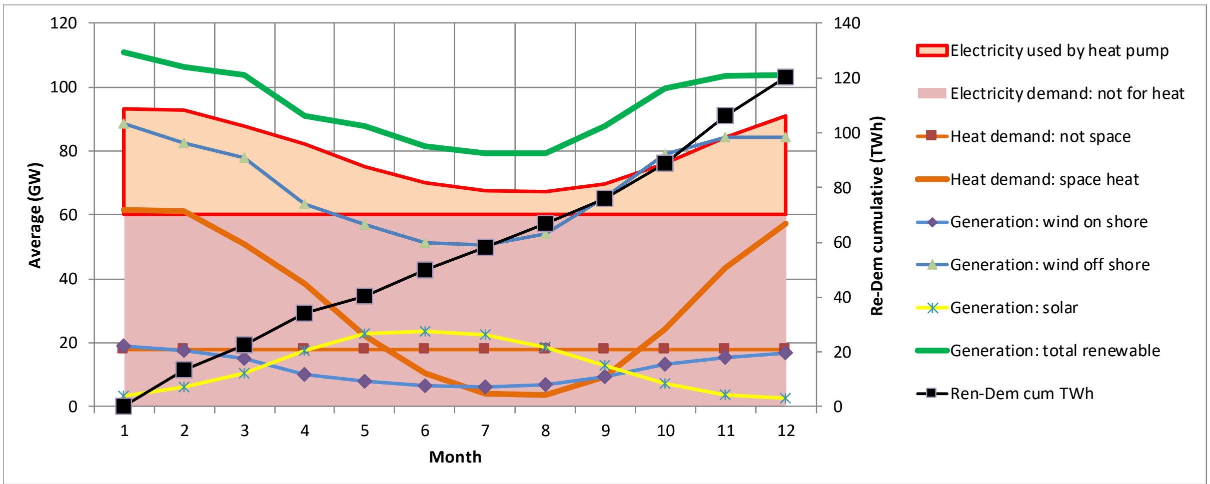
Table 2 : Systems 1 & 2 – renewable capacities

	System 1	System 2.1	System 2.2	System 2.3
Wind capacity: onshore	40	40	40	40
Wind capacity: offshore	120	130	140	160
Solar PV capacity	70	110	110	120

Some detail is first shown for the System 2.1 simulation, with a summary of System 1 and 2 given at the end of this addendum.

Average monthly results for 2.1 are shown in Figure 17. There is an average surplus of 120 TWh at the end of the year; this is 19% more than average annual demand.

Figure 17 : Average monthly flows 1980-2010 (System 2.1)

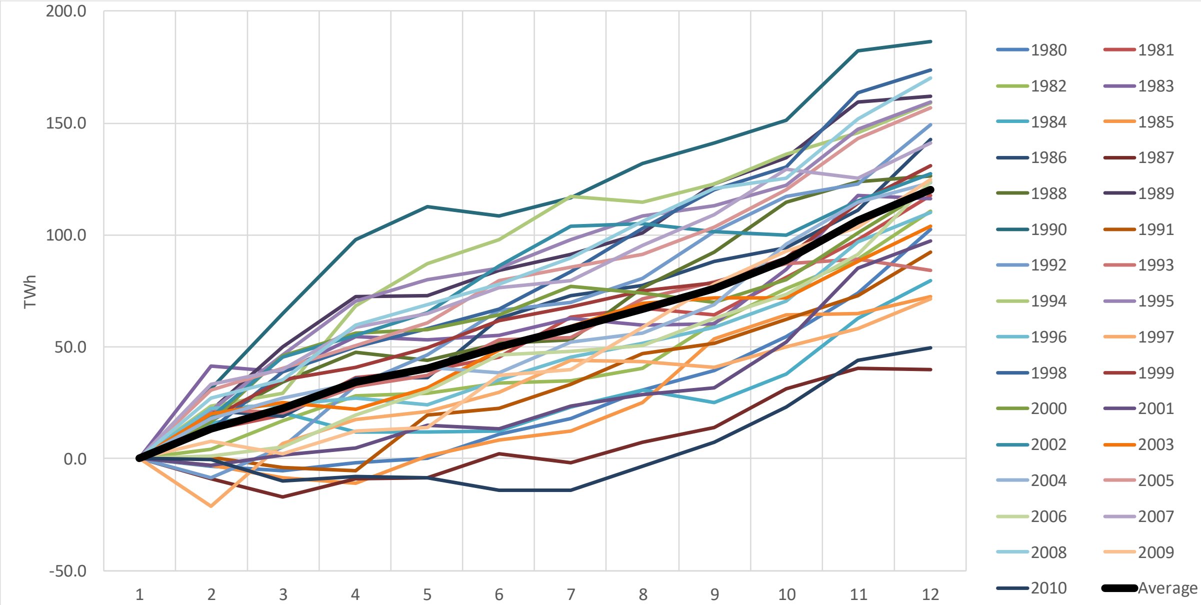


The cumulative deficit (renewables-demand) for each month and year for System 2.1 is shown in Figure 18. The solar capacity has been increased by 57% as compared to offshore wind (8%) with the result that the maximum cumulative deficits are quite evenly spread over the first 6 months of the year: and are 21 TWh (month 2, 1997), 17 TWh (month 3, 1987) and 14 TWh (month 6, 2010). The deficits are more evenly spread across the year as compared to System 1.

The maximum deficit of System 2.1 is 21 TWh in 1997 as compared to the System 1 maximum of 60 TWh: this is the minimum amount of energy needed ‘in store’ at the beginning of the year. The minimum storage need is reduced by 40 TWh (65%) through increasing generation to give an average annual surplus of 120 TWh (19%). Comparing

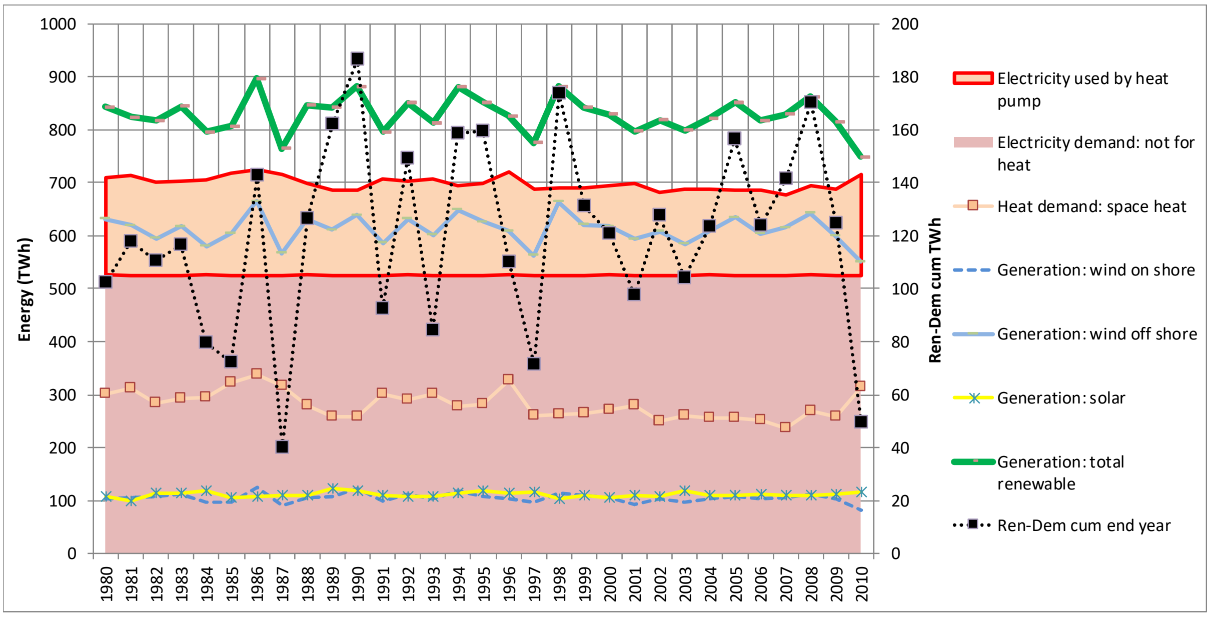
Systems 1 and 2.1, we see the trade-off between minimum storage need and renewable generation capacities.

Figure 18 : Monthly cumulative renewables-demand - 1980 to 2010 (System 2.1)



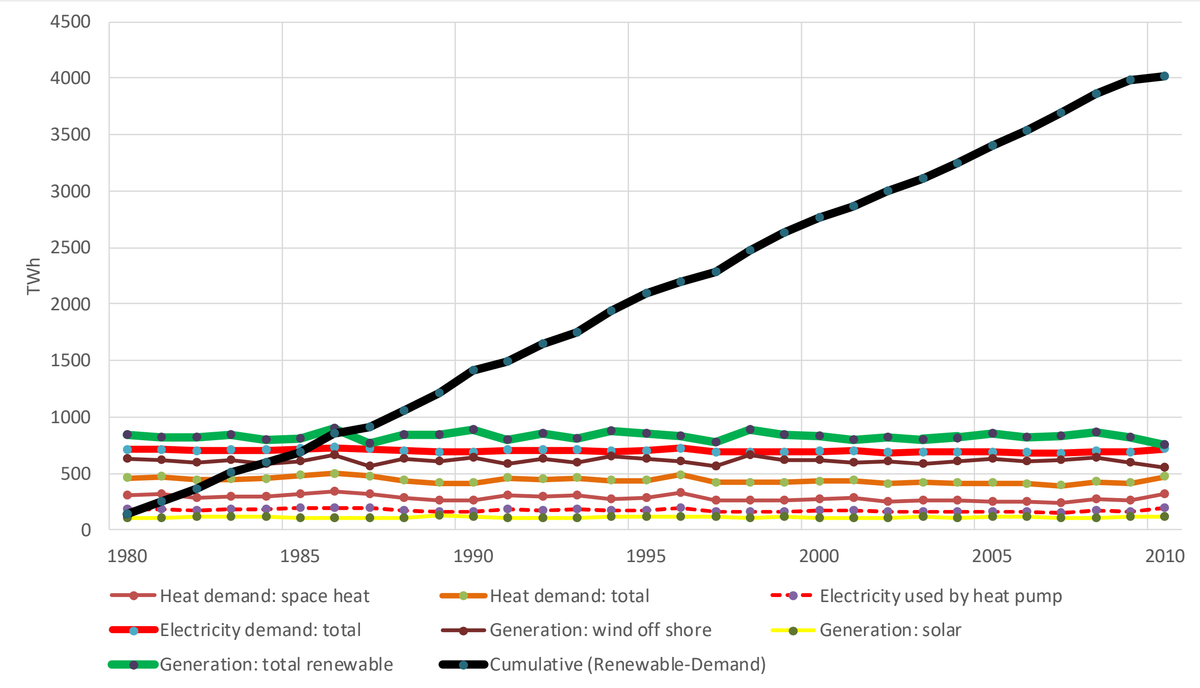
System 2.1 annual results are shown in Figure 19. The annual surplus of generation for every year is clear, but of course there are still deficits in some months of some years as shown in the previous Figure.

Figure 19 : Annual results 1980 to 2010 (System 2.1)



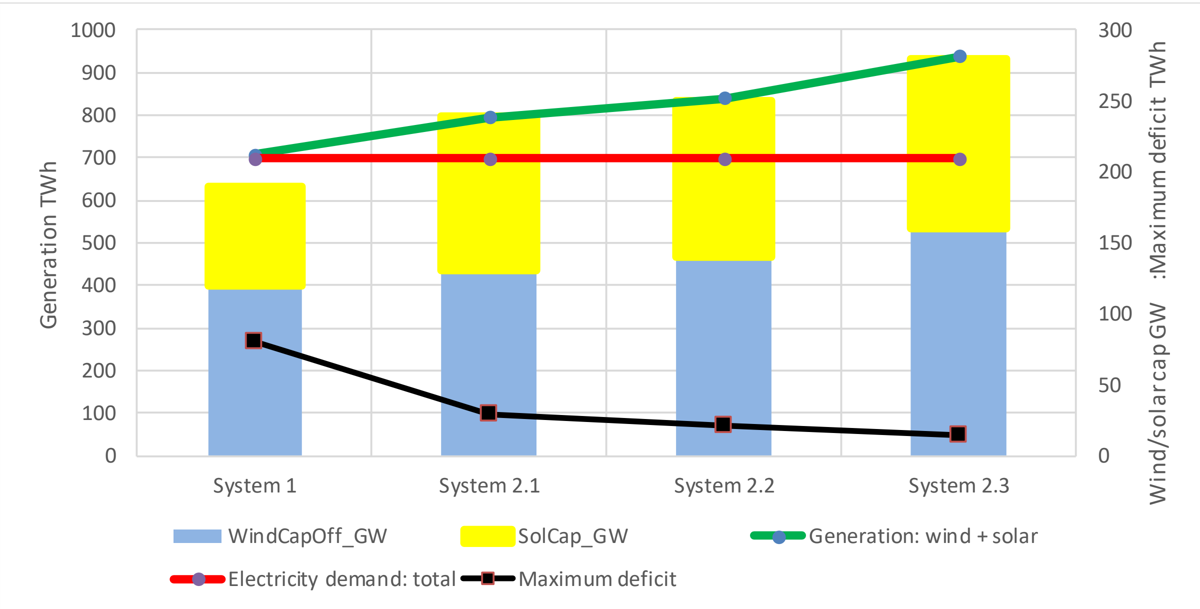
And there is a cumulative surplus of 4000 TWh over 31 years as shown in Figure 20.

Figure 20 : Cumulative supply-demand 1980-2010 (System 2.1)



The four Systems 1, 2.1, 2.2, and 2.3 were simulated over 31 years with summary results shown in Figure 21 . The excess generation over System 1 rises: to 14% in System 2.1, 20% in 2.2, and 34% in 2.3. The maximum deficit decreases, but slower than the excess generation – there are decreasing marginal benefits in terms of storage need by increasing generation with the assumed mixes.

Figure 21 : Renewable generation and maximum deficit for System 1 and 2



A proportion of the excess generation might be stored (e.g. as hydrogen or ammonia) but absorbing excess engenders costs – for example for hydrogen electrolysers and storage and the more absorbed the lower the capacity factors of storage systems. Ultimately adding to

UK storage would be futile as the stored energy would never be used in the UK and therefore the excess would either be spilled or exported.

Export could be in the form of electricity or in the form of synfuels such as hydrogen or ammonia, but this may be less desirable as it is perhaps lower cost and higher efficiency to export surplus electricity and have the hydrogen or ammonia synthesis plant sited in other countries. Synthesis plant in central Europe might produce at a lower total cost than in peripheral countries. The surplus might also release some biomass for export, but this is unlikely because the current UK biomass is probably insufficient to meet aviation fuel demand, even with supplementary energy and electrolytic hydrogen.

The simple model has illustrated the interplay between two of the options - storage and renewable capacity - for variable demand and supply matching. In ESTIMO the model is of a more realistic system and it includes the third option of European interconnector trade which has been shown to have a major impact on storage need – see Gallo Cassarino et al (2018). In ESTIMO, the capital and operational costs of all components are calculated such that optimal least cost combinations of the basic three balancing options can start to be identified – see Gallo Cassarino and Barrett (2021).

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SI 3 Modelling the Need for Storage

3.1 Introduction

Many estimates have been made of the need for storage (Cebulla et al[1] refer to 17 studies of storage needs in the USA, Europe, and Germany, that considered over 400 scenarios, and others are cited below). This section describes factors that affect the need for storage that were identified in previous studies and in work done in support of this report, and then summarises the results found in studies of the need for storage in different regions.

Studies made by MIT (which is mainly focussed on the USA) and by AFRY Management Consultancy (which is focussed on GB), both of which appeared after the literature review with which this study began was completed, are described separately in Annexes SI3 1 and SI3 2. They reach very different conclusions from those in this Report.

The foundations for much of the analysis of the effects of wind and weather and the need for storage described in this report were laid Cosgrove and Roulstone[2], whose paper on costing storage in GB is attached as Annex SI8.

Key Factors

Size of the grid

The need for storage depends strongly on the wind and solar resource, and other factors that depend on geography, such as the potential for hydropower and the availability of biomass. It also depends on the size of the electricity transmission grid. Grids that cover large areas average wind and solar supply over different weather systems and climates, and over different patterns of demand in different time zones. Generally speaking, the larger the span of the grid, the smaller the need for storage, relative to demand.

It was shown in Chapter 2 that, without (Figure 9) or with (Figure 10) baseload generation, GB's demand for electrical power cannot be met by wind and solar energy alone: however much they generate on average, there are always times when there is not enough. That this is true generally[3,4], even if it is assumed that electricity is transmitted by a continental scale grid, has been shown by:

- Shaner et al[5], whose study of the contiguous USA found that, whatever their level, wind and solar energy cannot meet demand, even with the support of a grid that spanned the 48 adjoining States, which (if it existed) would average supply over different climates and weather systems, and patterns of demand in four different time zones (see below for more details).
- Tong et al[6], who used the same approach as Shaner et al to show that wind and solar cannot meet demand on their own in 42 countries outside the USA.
- Gils et al[7], whose study of Europe (including the UK), which used a pre-net-zero model that included fossil fuel generation, implicitly shows that the same is true for Europe. This is not surprising given that the climate and weather are less diverse than in the USA and most of the population live in a single time zone.

The effect of grid size was shown very clearly in a detailed study of the US electricity system by Brown et al[8]. Using a 'co-optimized capacity-planning and dispatch model' for seven years of hourly weather, they found that inter-state coordination and transmission expansion reduce the system cost of electricity in a 100%-renewable US power system by 46% compared with a state-by-state approach, from 135 $/MWh to 73 $/MWh. Their sensitivity analyses found that reductions in the cost of photovoltaics, wind, and lithium-ion batteries lead to the lowest electricity costs for systems in which transmission expansion is allowed, while cost reductions in long-duration energy storage lead to significantly lower energy costs and nuclear power produced the largest electricity cost reductions for isolated systems.

Length of weather sequence

Many authors have stressed the need to base models of wind and solar generation on observations of weather over long-periods, starting with Barrett et al[9] (who used 30 years of data) in the case of the UK. This was anticipated in Chapter 2, where it was reported that the UK Met Office study found that the 37-year period used in this report is not long enough to fully sample possible rare weather events, implying the need to include contingency, as discussed further below. The authors of most of the papers quoted in this chapter were well aware of the need to look at long periods (of those already cited, Cosgrove and Roulstone used 37 years, Shaner et al studied 36 years, Tong et al 39 years). However, some studies focused on shorter, or supposedly 'characteristic', periods, e.g. Gils et al used data for 2006-14; Hunter et al[10] used model load factors for the year 2050 found by Zhang et al[11], in a report for the National Infrastructure Commission, Aurora[12] modelled a single high stress event, while as discussed in section 8.9 a number of studies by AFRY looked only at single years. Studies of short periods seriously underestimating the need for storage.

The work by Dowling et al[13] who modelled the contiguous USA, assuming complete, lossless, interconnection, shows the sensitivity to the length of the weather sequence studied and the period chosen. They used 39 years of weather data, which they broke down into 1 year, 2, 3, 4, 5 and 6-year sequences (apparently, they never looked at all 39 years together). They found that for a single year, the storage they modelled, has to be able to meet 220 to 500 hours of mean demand, depending on the year. In contrast, in (non-overlapping) 6-year periods, it has to be able to meet 520-800 hours.

The need to look at long periods was stressed particularly by Ruhnau and Qvist[14], whose study of renewables in Germany, which was based on 35 years of weather data, is described in more detail later. They observed that, although periods with persistently scarce solar and wind supply generally last no longer than two weeks, they lead to much larger storage needs than this might suggest because large shortfalls in supply can follow each other closely, not leaving enough time to refill stores. The importance of looking at long periods is vividly illustrated by the modelling of electricity systems based on wind and solar energy supported by hydrogen storage that is described in Chapter 3. It shows (see Figure 13) that while in the 23 years 1986-2008 all demand could have been met with a hydrogen storage capacity $\geq$ 50 TWh, in the 37 years 1980-2016 at least 100 TWh would have been needed. Much of the difference is due to clustering of periods of low wind speeds in 2010 (as seen in Figure 13), as discussed in section 8.7 where it is shown that this clustering prevents demand management reducing the need for storage significantly.

To allow for the fact (SI 2) that 1980-2016 does not provide a full sample of the spectrum of rare weather events, and for the possible effects of climate change, contingency is included in estimates of the need for storage in this report. It would be very interesting to examine the need for contingency by studying earlier periods, including the late 1960s and early 1970s, when average wind speeds were lower: this would require constructing ersatz wind and solar power outputs from the relevant weather data.

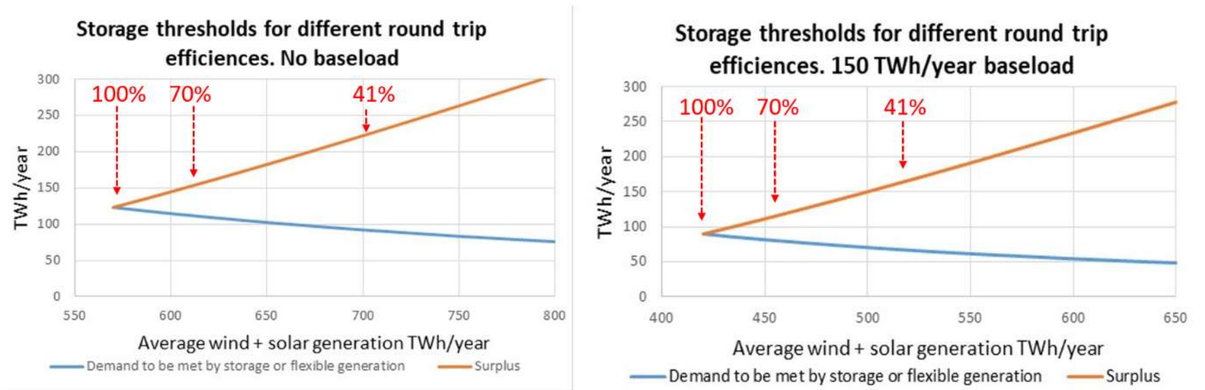
Solar/wind mix

Many authors have studied how residual demand for energy, and hence the need for storage or other flexible supply, varies with the mixture of wind and solar generation. Shaner et al[5] studied the case of the USA, and Tong et al[15] examined the situation in 43 other countries. In the case of the UK, Cardenas and Garvey[16] and Cosgrove and Roulstone[2] found that the need for storage is minimised for a mixture of around 20% solar/80% wind. This was already discussed in Chapter 2, together with the way in which the mixture that minimises residual demand varies with the levels of wind plus solar supply, baseload and demand. The minimum was found to be rather shallow (see the discussion accompanying Fig 6), and the amount of energy that has to be delivered by storage (or other flexible supply) changes very little for a solar share between 10% and 30%. However, while storage has to shift energy from the winter to the summer with 10% solar, it has to shift energy from the summer to the winter with 30%. This may influence the type of storage that is required, as found in the modelling used by Cosgrove and Roulstone does.

Storage efficiencies

The amount of energy that has to be delivered by storage depends on demand, the weather and what sources of supply are available other than wind and solar. The amount that has to be stored depends also on the efficiencies as discussed in section 1.3. Inefficiencies are included in most of the papers referenced in this chapter (but not all, e.g. Shaner et al and Tong et al studied systems with 100% efficient storage).

The threshold at which wind plus solar supply supported by storage can meet demand depends of the efficiencies of the stores that are used, weighed by the amount of energy that they deliver on average. This is illustrated in Fig SI 3.1 and Table SI 3.1. However, as discussed in section 3.2.1 at the 'threshold' energy the storage volume and input power would have to be very large, and it is desirable to go to higher level of wind and solar generation to reduce the size of the storage system and its cost.



Figures SI 3.1 A and B The orange lines show the average annual surplus as a function of the average level of wind + solar generation, i.e. the hour-by-hour sum of [(wind + solar + baseload) supply – demand]) averaged over 37 years (with of the Ninja Renewables model of wind and solar supply and AFRY's model of 570 TWh/year GB demand, discussed in Chapter 2). The blue line is the annual average of demand that cannot be met directly by wind, solar and baseload supply. At the 'threshold' energy, above which all flexibility could be provided by storage: (the average surplus) x (round-trip-efficiency) = (the average unmet demand).

Baseload TWh/year	Round trip efficiency		
	100%	70%	40.6%
0	570	617.6	703.5
150	420.1	454.7	520.9

Table SI 3.1. Threshold energies (as shown in Figures A and B), above which all flexibility can be provided by storage, for different round-trip storage efficiencies. 70% and 40.6% are the efficiencies assumed later in this report for Advanced Compressed Air Energy Storage and hydrogen storage respectively.

Timescales

The time scales on which residual demand fluctuates are discussed in section 3.1. In the case of GB, they were was discussed by Cardenas and Garvey[16] and at length by Cosgrove and Roulstone[2] whose modelling allocated energy to different types of store in a way that is related to when it is needed. Their modelling procedure casts interesting light on the typical time structure of surpluses and deficits. They considered three types of store - S (Short), M (Medium) and L(Long), whose use is scheduled on the basis of week ahead forecasts of supply and demand. Surplus energy is allocated to S if can be used to meet residual demand within six hours, any left is then allocated to M if it can be used within a week, and any remaining surplus is allocated to L. In filling deficits, the contents of S and M are used as foreseen when they were filled, and any remaining deficits are filled from L. Some results found with this procedure are shown in Table SI 3.2.

2050 demand with 30% Overcapacity, & 25% Baseload	**In/ output Power GW**	**Physical Size TWh**	**Energy delivered by store TWh/year**	**Equivalent full cycles/year Size**
Long - >1 week	128	55	22	0.4
Medium – 1 week	133	3	52	17
Short – 6 hours	74	0.2	8	40
Total Storage		**58**	**86**	

Table SI 3.2 Results found by Cosgrove and Roulstone with the storage efficiencies reported in section 3.3.5. 2050 demand is assumed here to be 600 TWh/year, of which 25% (150 TWh/year) is met by baseload. With the definition of overcapacity[i] used by these authors, 30% overcapacity means that wind plus solar provide an average of (450 + 0.3 x 600) = 630 TWh/year. The number of full cycles underrepresents the frequency with which the store is used as there are many partial cycles.

The table shows that some 10% of deficits can be filled with energy that is dispatched within six hours of being stored, and some 50% can be filled with energy stored for under a week, which demonstrates the potential importance of medium-term storage. **However**, with this approach, the capacities of M and S are designed to deliver as much electricity as possible within six hours or a week. M and S could be made smaller leaving more energy to be delivered by a larger L. Whether or not this is desirable is a question of costs.

Interplay of charging rates, storage capacities and the level of wind and solar supply

The interplay is discussed in section 3.2 and illustrated in Figure 12 in the case of a single type of store. It appears that the trade-off between volume and charging size was only explicitly noted recently[17]. Many studies have sought the minimum store size, implicitly assuming that

[i] Overcapacity is defined as a level of wind + solar capacity that produces an average annual output greater than average annual (demand – baseload supply). When expressed as a percentage the meaning is that with, e.g. 20% overcapacity, average annual wind + solar generation = 1.2 x annual demand. With baseload, different definitions are used by different authors, as discussed in the Glossary.

enough charging power is available to store all surpluses, which generally leads to an underestimate of the store size and an overestimate of the cost.

Scheduling

The question of how to schedule their use when more than one type of store is deployed was discussed in Section 3.3. The scheduling procedure used in the modelling on which the conclusions of this Report is described in Section SI 3.3 below. Cosgrove and Roulstone used a procedure that is based on week-ahead forecasts of hourly demand and of wind and solar supply to schedule the use of three types of store (S, M and L) that are distinguished by their decreasing capital costs per unit of energy stored, and increasing efficiencies. They prioritised storing energy in S when the forecasts foresaw that it could be used within six hours, followed by M if it could be used within a week, leaving any remaining surpluses to be stored in L. S and M were discharged as foreseen when they were charged, and L - acting as a backstop – was then discharged to fill any remaining vacancies. This procedure ensures that the most expensive store S is cycled more often than M, which is cycled more often than the least expensive L, and as S type stores are generally more efficient than M type, which are more efficient than L type, it helps minimise input power, as well as ensuring the efficient use of capital. This method provided many important insights but it was found that, unless the charging and discharging rates were constrained, S, M and L were all required to provide almost the full range of residual power, leading to an apparently unacceptably high cost of electricity. Cost minimisation is not straightforward with this scheduling procedure[ii], which in the first instance uses scheduling rather than costs to determine store sizes.

Building on the work of Cosgrove and Roulstone, Zachary[18] introduced the ideas that

i) The state of charge of different stores should be taken into account in scheduling their use (an idea adopted in the modelling described in section SI 3.3). This changes the way that the need to store and dispatch power is shared between the stores and reduces the probability that the 'long-stop' hydrogen store becomes empty, thereby reducing in the total capacity to absorb and dispatch power and the size of the hydrogen store, and reducing costs.
ii) Allowing one type of store to charge while another is discharging, which could lead to a less expensive combination of store sizes and discharging powers.
iii) Since the tail of high residual demand appears to decrease exponentially (as can be seen Figure 11 in the case that correlations between wind plus solar supply and demand, which will slow the decrease, and not included in detail) it may be possible to meet acceptable reliability standards without meeting 100% of demand.

More work is needed on scheduling procedures for storing energy and dispatching it from store, and on combining storage with other sources of flexible supply. Results found with hindsight (which provide a lower bound on the need for storage) should be used as a target in designing procedures that do not assume perfect foresight. The counterintuitive idea that allowing one type of store to charge while another is discharging may provide systems benefits deserves more attention. It would be interesting to study scheduling procedures that use seasonal (as well as weather) forecasts. It is generally not possible to predict day-to-day changes in the weather with much detail beyond a week ahead, but the reliability of long-range broad-brush forecasts is improving[19]. Scaife et al[20] have demonstrated that key aspects of

[ii] which was suggested at the outset of the study by Chris Llewellyn Smith, to the best of whose knowledge scheduling without hindsight had not previously been discussed,

European and North American winter climate and the surface North Atlantic Oscillation are highly predictable months ahead. Clark et al[21] have shown that this makes it possible to predict near-surface wind speed and air temperature and therefore energy supply and demand. They also demonstrated ‘good reliability’ of probabilistic forecasts of above/below-average wind speed and temperature. The results of a first attempt to use long-range forecast to mange demnd are reported in section SI 8.7.

Implementing any of the procedures described above would require coordination in designing and operating the storage system. Possible market reforms that could encourage, or ensure, the degree of coordination that will be needed to move to a zero-emissions electricity system cost-effectively are discussed in Chapter 9 and SI 9.

Selected estimates of the need for storage in different regions

USA

Shaner et al[5] examined the interplay of the level, spatial distribution and mixture of wind and solar supply, the size of the transmission grid and the level of storage. They showed that with solar and wind contributing over 80% of electricity demand, achieving the US grid reliability standard (of load loss less than one day in ten years, 99.97%) would require a strategic combination of energy storage, long-distance transmission, overbuilding of supply, flexible generation, and demand management. With only wind, solar and 100% efficient storage, they found that, with their assumptions, even with a lossless transmission grid spanning 10^7 km^2 and average wind plus solar generation equal to 2.2 x demand, meeting the reliability standard would require a storage capacity able to meet 12 hours of demand. With supply = 1.1 x demand, the standard could be met with 32 days of storage capacity. However, including storage and transmission losses would increase the required level of supply and/or storage. Furthermore, much more storage would be needed in realistic cases in which supply and demand are aggregated over the smaller areas that are discussed in the follow-on paper by Dowling et al discussed below.

Ziegler et al[22] modelled systems with high levels of renewables, supported by storage, in four locations, with four different stylised demand patterns, using 20 years of weather data. With a range of storage options which did **not** include hydrogen, synthetic methane, or ammonia, they found among other conclusions that:

- In a reliable system the average electricity cost (including the cost of curtailed wind and solar energy as well as storage) could be two or three times higher than the cost of wind plus solar.
- If additional sources of supply are included, and the requirement that renewables and storage meet 100% of demand is relaxed for even a small percentage of the time, the target cost for storage that could provide firm, cost-competitive, electricity would become much less stringent. Their modelling finds that using other flexible supplies 5% of the time could halve electricity costs.
- Electricity costs, are more sensitive to the cost of storage energy capacity than power rating.

Including hydrogen (or ammonia or synthetic methane) would completely vitiate the second conclusion according to the analysis described in in this report, which also finds that the sensitivity of electricity costs to storage capacity and power rating are similar in the case of hydrogen storage.

Dowling et al[13] used a macro-scale energy model to evaluate capacities and dispatch in a least cost, 100% reliable electricity systems with wind and solar generation supported by long-duration (defined as 10 hours or greater) and battery storage. As well as a base case that assumes lossless transmission from generation to load over all of the US, which provides a lower bound for the amount of storage required, they studied the Western, Eastern and Texas Interconnections, which are largely independent systems. They used 39 years of weather data, which they split into segments of 1 to 6 years, and found (as discussed above) that the dependence on long-duration storage increases when the system is optimized over more years. For the year 2018 they found their assumptions lead to a need for 393 hours of hydrogen storage for a fully interconnected US, which increases to 699 hours (29 days) for 2013-2018, and would be longer for longer periods.

They found that system energy costs are twice as sensitive to reductions in long duration storage costs compared with battery costs. Comparing US cost estimates with the GB estimates discussed later is difficult since the weather and patterns of demand and are very different, and the assumed storage parameters and costs differ widely. As just one example, Dowling et al assume 49% efficiency for power to gas storage, which is much higher than the 41% found in Chapter 4, and an electrolyser cost of $1,058/kW, which is higher than today's full system cost, which is $900/kW according to the IEA[23], and double the 2050 forecast cost of $450/kW used in Chapter 9. However, their overall conclusion, that high renewables supported by large capacity energy storage provided by power-to-gas-to-power systems can be both reliable and affordable, is in line with the conclusions of this report.

Tong et al[15] use a similar demand and supply model to Shaner et al to set targets for storage costs in systems with high renewables. They find that in order for such systems to provide economic and reliable electricity without extensive curtailment of generation, volumetric storage costs would have to fall to order $1/kWh – orders of magnitude less than the current cost of Li-ion batteries. The role of energy storage was found to change with the time period being considered. For short-term energy deficits, high-cost storage with over-capacity can economically meet hourly demand. For seasonal deficits, storage costs must be decades lower. Moreover, energy storage faces twin penalties - as capacity increases the additional storage is used less frequently while at the same time hourly electricity costs become less volatile, reducing the opportunity for price arbitrage for the additional storage. These conclusions are in line with those in this report.

Sepulveda et al[24] studied three large US electrical supply regions, each with its own weather and optimum solar/wind mix, assuming a wide range of energy storage technologies, using one year of demand data and six years of weather data. They set cost and efficiency targets for long duration energy storage that would allow it to displace other types of complementary dispatchable power: nuclear, CCGT plus CCS, or blue hydrogen. They found that storage capacity cost and discharging efficiency are the most important parameters, while charge/discharge power cost and charging efficiency play secondary roles. They concluded that in Northern latitudes increases in demand for heating would make the full displacement of dispatchable generation more challenging and would require performance combinations unlikely to be feasible with known long duration storage technologies (this differs from the conclusion of this report as far as GB is concerned). Finally, the storage technologies with the greatest impact on electricity cost and firm generation were found to have storage capacities exceeding 100 hours, i.e. the need for long-term storage is much more than the few hours often assumed.

Guerra et al[25] studied the US Western Interconnector region assuming variable renewable penetrations of 24% to 61% (up to 83.5% of renewable energy including hydro, geothermal, and biomass power), using eight years of weather data, which they studied a year at a time, as a result of which their conclusions on the storage capacity that will be needed should be treated with caution. They assessed the cost competitiveness of pumped hydro, compressed air, and hydrogen seasonal storage, and explored the conditions (cost, storage duration, and efficiency) that encourage cost competitiveness for seasonal storage. They found that pumped hydro and compressed air energy storage with one day of discharge duration are expected to be cost-competitive in the near future. In contrast, it was found that hydrogen storage with up to one week of discharge duration could be cost-effective in the near future with power and energy capacity capital costs less than \$1507/kW and US\$1.8/kWh respectively (the power cost target is well within the 2050 cost projections discussed in Chapter 4, while the H21 NE consortium quoted there thinks that in suitable sites underground hydrogen storage in solution-mined salt caverns could be provided for \$0.36/kWh_{LHV}). Based on projected power and energy capacity capital costs for 2050, hydrogen storage with up to two weeks of discharge duration was expected to be cost-effective in future power systems. Moreover, storage systems with greater discharge duration could be cost-competitive in the near future if greater renewable penetration levels increase arbitrage or capacity value, significant energy capital cost reductions are achieved, or revenues from additional services and new markets—e.g., reliability and resiliency—are monetized.

Two other studies of the Western Interconnection area that assume 85% renewable penetration, including large hydro, deserve mention, although their quantitative conclusions should be treated with caution as they only looked at a single year of weather data:

Zhang et al[26], who considered storage with assumed round-trip efficiencies between 40% and 80% corresponding to: power ↔ hydrogen, CAES, redox flow battery, and pumped hydro storage, found inter alia that the diurnal value of energy storage is higher than the seasonal value.

Hunter et al[10] provide comparisons of the current and future costs of delivering energy from different types of storage for the US Western Interconnection. Their work uses the 2050 load factors found by of Zhang et al but the analysis is extended to include lower cost but lower efficiency storage technologies such as hydrogen stored in caverns. They find that as variable renewable energy penetration increases beyond 80%, clean power systems will require long-duration energy storage or flexible, low-carbon generation to support power grid reliability. They show that for a 120-hour storage duration rating, hydrogen systems with geologic storage and natural gas with carbon capture are the least-cost low-carbon technologies for both current and future capital costs. Within the range of costs, adiabatic compressed air and pumped thermal storage could be the least-cost technologies for current cost cases for 12-hous and also in some cases for 120-hours.

Europe

Many studies of the European electricity system have examined the need for storage under a very wide range of assumptions. A paper by Cebulla et al[27], which is more transparent than some others, modelled the amount of storage that would be required in an interconnected Europe (meaning the EU as constituted in 2017) in 2050 using their ReMIX capacity expansion model. They assumed that at least 80% of electricity demand is met by wind and solar, with the rest provided by dispatchable hydropower, biomass or Concentrated Solar Power (which is not a viable option in GB) supported by thermal storage, with the balance from unabated fossil fuel generation. The storage technologies they considered were Li-Ion batteries, ACAES, Flow Batteries, pumped hydro and hydrogen stored in caverns.

The model of wind and solar generation was based on weather data for the years was 2007-12, which they studied one at a time, inferring sensitivity by comparing different years. Short and medium-term storage was found to be required to balance daily and weekly fluctuations from PV and onshore wind, while hydrogen storage was particularly important for longer periods of low solar irradiation and wind speeds. Both hydrogen storage and Li-ion batteries, which are a good complement to solar PV, were found to be more cost effective than alternatives forms of storage, and to depend for their economics on frequent cycling. They assumed a 2050 electricity demand of 2,400 TWh/1,200 GW, and a storage system able to deliver 200 GW (since the model includes some dispatchable power, it is possible to fix the power that must be provided by storage). The model then found a need for a storage capacity of 30 and 54 TWh/year (it is not clear if this is the energy stored or the energy that storage is able to deliver; if the latter, it is enough to meet 110-200 hours of average demand – more if the former).

Cebula et al's paper underlines the need for electricity storage in energy systems characterized by high (> 80%) shares of wind and solar even with a high degree of interconnection (and finds that storage would be even more essential if the envisaged grid expansion is delayed).

Price et al[28] modelled the design of a UK power systems embedded within a wider European energy system. Their paper, only presents results for the UK, but their model is designed to optimise the European system as a whole and the implication is that an interconnected Europe could reach an electrify generation emissions target of 2g CO2/kWh with long-term hydrogen storage enabling the lowest cost systems.

Germany

Ruhnau and Qvist [14] studied energy systems powered by 100% renewables in Germany. As discussed above, their analysis of 35 years of weather data revealed that although periods with persistently scarce supply may last no longer than two weeks, the maximum deficit occurs over longer periods because such periods can cluster. Allowing for losses and charging limitations, the period defining storage requirements can be as much as 12 weeks. They assumed a demand of some 545 TWh/year, and that supply is provided by small amounts of hydro and biomass and almost 300 GW of wind plus solar generating capacity (which deliver an average of 160 TWh/year to storage, and 84 TWh/year that is curtailed), comprised of 92 GW solar PV, 94 GW onshore and 94 GW offshore wind. At the cost minimum, storage capacities were found to be 54.8 TWh hydrogen, 1.3 TWh existing pumped hydro (no other medium-term storage was included), and 59 GWh batteries. Accounting for discharging efficiency, if fully discharged this storage would supply of 36 TWh electricity, or about 7% (24 days) of the average annual load (it was assumed that pumped hydro and batteries have round-trip efficiencies of 80% and 90% respectively, and hydrogen is produced by 80% efficient electrolysers and converted to power by combined cycle turbines with 63% efficiency). With the assumed capital costs, lifetimes O&M costs, listed in the paper, and a 6% discount rate, they found an average electricity cost of slightly over €80/MWh. These results are relevant to the UK because of the similarities of weather. Ruhnau and Qvist point out that on the one hand they may have overestimated storage needs and costs as they treated Germany as an energy island, but on the other they may have underestimated them as they do not consider the future impact of climate change. The fact that perfect foresight was assumed must also result in underestimates. However, in so far as they can be compared, Ruhnau and Qvist's results align well with those in this report.

Great Britain

Early studies that deserve mention include those of

Strbac et al[29] whose study of the options for decarbonising heat in the UK in 2050 was one of the first to stress the need for flexible electricity generation in low carbon systems. In an analysis based on limited weather data, which allowed for 40 GW of infrequently used gas turbines, they found a need for 20 TWh of hydrogen storage.

and

Barrett et al[30] who were the first in the UK to recognise that deficits in residual demand are very large and needed to be analysed with supply based on many years of weather. Their recent work[31] on residual energy, which is described in Chapter 2 and Annex 2 of SI 2, noted that deficits occur in clusters, and that even if 100% efficient, some 50 TWh (25 days of mean demand) of storage would be needed.

Cardenás et al[16], whose work was cited above, studied the current UK energy system, assuming 335 TWh/year demand, using nine years of historical weather data. They showed that storage needs are significantly underestimated if the inter-annual variability of wind and solar is not captured, and recognised that nine years might not be enough. Their paper provides a systematic study of storage needs as a function of the wind/solar mix and the level of wind and solar supply. They analysed costs assuming that all storage is provided by ACAES. However: i) they did not include the cost of O&M and they annualised the assumed capital costs of storage with a 0% discount rate (B Cardenás, University of Nottingham, private communication) so *their conclusions on the cost of electricity should be treated with caution*, and ii) even with demand of 33TWh/year, found a storage volume greater than the maximum potential capacity for ACAES using salt-caverns according to the analysis reported Section 5.2 and SI 5.

A subsequent paper by **Cárdenas and Garvey**[32] modelled and costed a mixture of hydrogen storage (assumed to have a round trip efficiency of 45%), ACAES and Li-ion batteries, also using nine years of weather data. Their interesting analysis is however effectively replaced by the multi-store modelling used in this report, which was carried out by Garvey, in which different input costs were used, 37 years of weather data were studied, O&M was included and capital costs were discounted.

Many of results found by **Cosgrove & Roulstone**[2], whose work laid the foundations for much of the analysis of the need for storage in this report, have already been quoted. They used an hour-by-hour model of 2050 electricity demand of 600 TWh based on profiles provided to the Committee of Climate Change by Imperial College[29] (this profile has some very peculiar features, as noted in footnote ii in SI 2, but this has little impact on the broad-brush conclusions), and the 37 years of weather data described in Chapter 2. They observed that storage technologies broadly fall into three classes, with the following characteristics:

- Electro-chemical: high round trip efficiency 90-95%; volumetric energy storage costs some 100 times those of chemical storage, but lower power costs than for thermo-physical or chemical systems.
- Thermo-mechanical: mid round-trip efficiency 45-70%; volumetric energy storage costs some 10 times those of chemical storage.

- Chemical: low round-trip efficiency 25-42%; low volumetric storage costs

These characteristics match those assumed for the Short (S), Medium (M) and Long (L) stores used in their scheduling procedure, described above. In modelling, they assumed round-trip efficiencies of 90% (characteristics of Li-ion batteries) for S, 70% (assumed to be characteristic of Advanced Compressed or Liquid Air Energy Storage), for M, and 40% or 25% (assumed to be characteristic of hydrogen or ammonia storage) for L. Their paper contains

- detailed analyses of residual demand;
- numerous plots, found with their scheduling procedure, of the storage capacities of S, M and L and the energy they deliver annually, as functions of the wind/solar mix, with 100% efficient stores and with the efficiencies listed above, without and with various levels of baseload contributions;
- plots of the contents of the different stores as a function of time the different cases.

Important results include the findings that:

- Many tens of TWhs of energy storage will be needed - much more than found by studying a single year, or considerations based on selected periods which do not capture the time structure of surplus and deficits.
- Store sizes are significantly affected by the solar/wind mix.
- Overcapacity deceases the size of the Long store from 98 TWh at 20% overcapacity to 55 TWh at 30%, and then to 47 TWh at 40% in the case without baseload.
- With the scheduling procedure that was used, the Medium store delivers the most energy up to 40% solar share, and which point L takes over as the ultimate backup.

However, as noted earlier, the procedure leads to sizes for S and M that are capable of delivering as much electricity as possible within six hours or a week. This reduces losses in storage because they are more efficient than L, but does not necessarily lead to the lowest system cost. Costs may be lower in models in which M and S are smaller, and deliver less energy, while L is larger. Furthermore, in this model neither charging nor discharging rates are constrained. As a result, it generally underestimates long store size, and overestimates costs, as discussed in section 3.2.6, and almost every store has to be able to meet almost the full range of residual demand for power.

In their analysis of the cost of storage (reproduced as an Annex to SI 8), the scheduling procedure developed with Zachary was also used, with which (as described above) the need to deliver power is shared between stores, in a way illustrated in Table SI 3.3

Store characteristics - 30% over overcapacity, no baseload						
Maximum demand in model used 166 GW*	Short		Medium		Long	
	Physical capacity	Input & output power	Physical capacity	Input & output power	Physical capacity	Input & output power
Cosgrove and Roulstone - unconstrained	232 GWh	60 GW	2.8 TWh	125 GW	55.3 TWh	125 GW
Zachary – constrained to share power	50 GWh	20 GW	4.8 TWh	60 GW	66.5 TWh	60 GW
*Compared to 98 GW in the AFRY model used in modelling in this report						

Table SI 3.3 Energy store characteristics found by Cosgrove and Roulstone and Zachary

Estimates of the Cost of Powering GB with High Level of Wind and Solar and Storage

The average cost of electricity in GB with very high levels of renewables supported by storage has been estimated i) by Roulstone and Cosgrove, ii) by Price et al, and iii) in this report (which effectively replaces the study by Cardenás and Garvey). Despite large differences in assumptions and methodology, these studies

- All agree that a net-zero GB will need many tens of TWh of storage in 2050.
- Find average costs of electricity that are not dissimilar. This is because the cost of wind and solar power (used directly plus stored plus curtailed) makes the largest contribution. The average cost is higher (by 70% or more) than the cost of the input wind plus solar power.

Roulstone and Cosgrove, whose papers is attached as an Annex to SI 8, treated GB as an energy island, as done in this report. They estimated the average cost of electricity as a function of the level of wind and solar generation using data from Cosgrove & Roulstone, with and without the 30% baseload supply, including the cost of curtailed wind and solar power, but not of transmission and providing grid services. They found, as expected, that the anticipated future reduction in storage costs and sharing power between stores (i.e. using Zachary's modification of their original storage procedure) both lead to significant reductions in the cost of electricity. The costs of electricity that they found was somewhat higher than those found in this report because of different cost assumptions, and because i) although they adjusted power and store sizes with an eye on costs, they did not minimise the system cost systematically, and ii) the maximum demand in the model they used was much higher than in the AFRY model.

Price et al[28] modelled the design of a UK power systems embedded within a wider European energy system that meets the countries' 2050 emissions targets. Annual emissions from electricity generation were constrained to 2g CO_2/kWh (based on the CCC's Balanced Pathway[33]), and this limit is extended to cover Europe to ensure that the UK does not import high-carbon electricity. The model of the electricity system covers the UK, broken down into 9 zones, and a further 27 European countries aggregated into an additional nine zones. The effect of interconnectors is modelled assuming either i) the capacities proposed for 2027 (16.5 GW of interconnection of the UK with Europe, including land-based transmission between GB and Northern Ireland and Ireland), or ii) capacities that are treated as free variables up to a limit of 50 GW per link, allowing hourly net imports into the UK to peak at 50% of total hourly demand (in both cases the model allows transmission within the UK to expand to its optimal level). The paper only presents results for the UK, but the model is designed to optimise the European system as a whole and the implication is that an interconnected Europe could reach a target of 2g CO_2/kWh with long-term hydrogen storage enabling the lowest cost systems.

The focus is on whether or not the UK's generation mix should include new nuclear in 2050. Hourly annual demand for the UK and Europe was based on 2012 data with additions for electrification of heat, road transport, manufacturing and electrolytic production of hydrogen for uses other than storing electricity. A regression model was used for each country to separate electricity demand into temperature dependent and independent portions, and the former was adjusted in line with the weather. This led to UK demand from 628 to 661TWh, depending on the weather year. 25 years (1993-2017) of weather data were studied separately, and results were then presented for the "worst" (2010), "average" (1995) and "best" (2014) years, defined as having the highest, median and lowest total European wide system costs. However, studying individual years does not capture long-term trends which are important is sizing storage needs. It is therefore probable that Price et al underestimated storage needs, and that consequently generation costs are higher than those they found.

Price et al present UK generating capacities (based on their model optimising total system costs), annual generation outputs and electricity costs for 36 combinations of three weather years, the two different assumptions about interconnectors discussed above, and the following three technology portfolios, with nuclear capital costs that correspond to generating costs of i) £86(2010)/MWh for a first of a kind plant, and ii) £68 (2010)/MWh for an n^{th} of a kind plant (both based on an assumed discount rate of 9%):

- 'Base': nuclear, closed and open cycle natural gas turbines equipped with CCS, solar and wind, Li-ion batteries, together with a small contribution from synchronous condensers which were included to provide grid stability.
- 'Base + BECCS': Base + BECCS limited to the CCC's estimated[33] biomass potential of 61 TWh/year, yielding 17 TWh/year of electricity with 28% efficiency.
- 'All': Base + BECCS + hydrogen storage.

The UK's long term storage need was found to be least in 2014 (when, expressed in terms of the lower heating value of the hydrogen stored, it was 63.6 TWh if interconnector expansion was allowed and 57.1 TWh if not) and most in 1995 (94.6TWh with expansion and 136.7 TWh without) The average costs of electricity in the UK in the worst year was found to be between £65 and £70/MWh in the Base cases, and 55 and £57/MWh in the third (All) cases (whether or not interconnectors are permitted to expand changes the cost by 6.9% in Base and 3.3% in All; the choice of nuclear cost has almost no impact). However, given that the optimisation assumed perfect foresight, these are lower bounds on the cost that could be achieved in practise.

The authors conclude that:

- New nuclear capacity is only cost-effective in the absence of BECCS, long-term storage and interconnector expansion, and assuming n^{th} of a kind nuclear with very ambitious construction times.
- BECCS reduces the average UK electricity cost by 5–15%, with greater savings seen for more challenging conditions (i.e. worse weather years; no interconnector expansion), as negative emissions facilitate the deployment of cheaper flexible assets.
- Long-term storage, modelled as hydrogen generated from electrolysis and stored in underground salt caverns, can support 9–21% cheaper UK systems, with more pessimistic assumptions for wind and solar leading to greater value from the flexibility that storage provides. When both long-term storage and BECCS are allowed, storage dominates and no BECCS is deployed.
- Synchronous condensers could have an important role in providing cost-effective inertia to support secure highly renewable systems in cases where synchronous generation is low. This includes Base cases in which no new nuclear is deployed and all of the systems with long-term storage.
- The cost-optimal minimum share of annual generation from domestic wind plus solar is found to be ~ 80% across all our scenarios, with long-term storage consistently enabling ~ 94% share even in the worst weather year.

No attempt has been made to compare these results with those found in this report since they are based on single year of weather, assume perfect foresight and involve a very large number of parameters and assumptions (e.g. that open or closed cycle turbines are used to generate power from hydrogen, which is not the cheapest option according to the analysis in Chapter 4). However, the volume of hydrogen storage and the costs that are found are similar, and the study of the effect of increasing the capacity of interconnectors (whose impact was not included in this report, for reasons explained in Chapter 2) shows their potential importance. Furthermore, the analysis in Chapter 8 also shows that, unless the cost is much lower than assumed (which could be achieved by Government guarantees that lower the risk for investors and hence the discount rate), including nuclear in the future generation mix would increase the cost of electricity. However, adding nuclear would reduce the wind and solar capacity that will be needed, make it easier to build enough by 2050, and it would add diversity.

3.2 Modelling and costing with a single type of store

Details of the modelling and costing outlined in Section 3.2 are described here. Details of the single step approach are described in SI 3.3.

Construction of Fig 3.1

Fig 3.1 is constructed by first finding V_{min} as a function of the electrolyser power G for an assumed level of average wind and solar supply, and then repeating the process for different levels of wind plus solar supply

With wind + solar supply fixed (at a value taken below to be 3 x demand = 741 TWh/year for purposes of illustration), the procedure is to step through each of the 324,360 hours in the 37 years studied, and

a) in hours in which there is a surplus (wind + solar energy > demand), add as much hydrogen to the store as it can accommodate, and as allowed by the electrolyser power,
b) in hours in which there is a deficit (demand > wind + solar energy), remove as much from the store as needed to fill the deficit.

There are subtleties connected with the choice of the initial level to which the store is filled, and its maximum size, which are best explained by describing the procedure formally. **Let:**

L_h = level in store at end of hour h

$(S/D)_h$ = (wind + solar energy supplied in hour h) – (demand in hour h).

When $(S/D)_h > 0$ this is **S_h = the surplus in hour h**

When $(S/D)_h < 0$ this is **D_h = the deficit in hour h**

Then

1. **Chose initial values L_o** and **a maximum level/store volume V_o** (it is convenient to choose L_0, which is adjusted in step 3, to be close to V_0: only $V_0 - L_0$, is significant - both L_o and V_o are shifted by a constant in step 4)

2. **Step through every hour, if in hour h there is**

   a) a surplus:

   if $S_h < G$ and $L_h = L_{h-1} + 0.74*S_h < V_0$, set $L_h = L_{h-1} + 0.74*S_h$

   if $L_h = L_{h-1} + 0.74*S_h > V_0$, set $L_h = V_0$

   [0.74 is the assumed electrolyser efficiency]

   if $S_h > G$ and $L_h = L_{h-1} + 0.74* G < V_0$, set $L_h = L_{h-1} + 0.74*S_h < V_0$

if $L_h = L_{h-1} + 0.74*G > V_0$, set $L_h = V_0$

b) **a deficit: set $L_h = L_{h-1} + 0.55*D_h$**

[0.55 is the assumed efficiency with which hydrogen generates electricity]

3. **Set $L_0 = L_{324,360}$ and repeat.** Setting $L_0 = L_{324,360}$ ensures that if the conditions in the next 37 years are the same as those in the 37 years studied, demand would be met[iii]; of course, they won't be the same, which is why in this study contingency is added to the size of the store.

4. **Find $V_{min} = V_0 - L_h^{min}$.**

This procure generates the blue curve in Fig SI 3.1 below, which is a section through Fig 3.1 for average wind and solar power = 741 TWh/year.

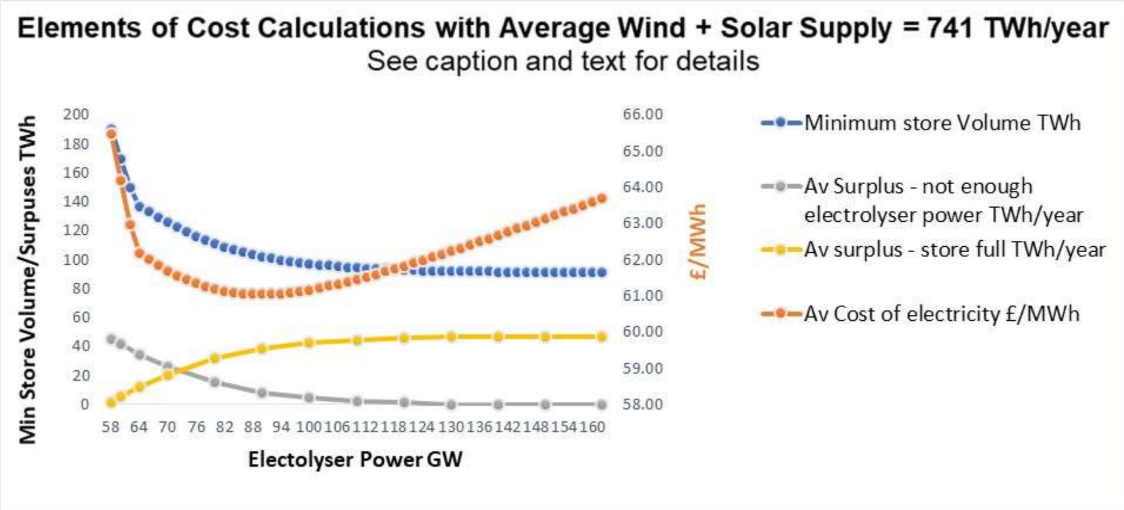


Fig SI 3.1. The average annual surplus wind and solar generated energy, that is not used for storage, is broken down according to its origin.

Finding the minimum average cost of electricity[iv]

With the base costs and assumptions in Table 5 in the report, and a discount rate of 5%, the average cost of power is given (as explained in SI 8.3) by:

£[(26.7 x electrolyser power in GW + 21.4 x size of the store in TWh_{LHV} +25.2 x maximum power output in GW) + (average wind + solar supply in TWh)*(cost/MWh of wind + solar energy)/(Annual Output TWh)]**/MWh**

Assuming: that storage must be able to meet demand of up to 100 GW, the mix of wind and solar power cost £35/MWh, and that a 20% contingency should added to the store size with $V = 1.2 \times V_{min}(G)$, this formula gives the orange cost curve in Fig S 3.1 as a function of the electrolyser power G. The region around the minimum was then explored in steps of 0.04 GW in G, to find the minimum which is a G = 82.3 GW, V_{min} = 108.7 (1.2 x V_{min} – 130.4 TWh). The

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[iii] The level in the store 'loses its memory' after it is first fully filled, and the same value of V_{min} would be found for any L_0 that satisfies $V_{min} > L_o - L_h^{min} > L_o - L_h^{min}$- 51,554 TWh, where with average supply = 741 TWh/year 51,554 TWh is the difference between L_o and the first minimum in the filling level (the difference looks a bit bigger in Fig 3.2 because there is an initial rise in the level which cannot be resolved on the scale shown).

[iv] Costing of the case of a single store in the Report were carried out by Richard Nayak-Luke. A significant sample of the results were checked by Chris Llewellyn Smith using an independently written programme.

cost in Fig SI 3.1 does not included the costs of transmitting wind and solar power to store and providing grid services, which are included in the costs given in the Report.

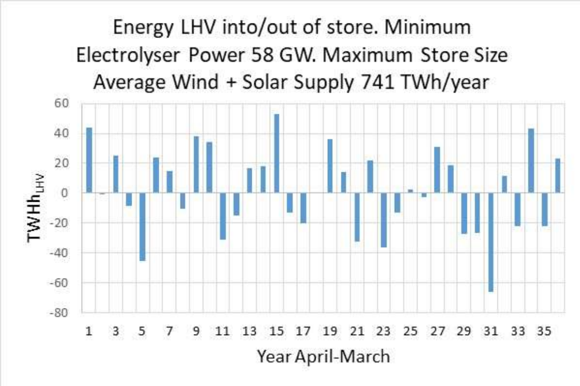
Surpluses

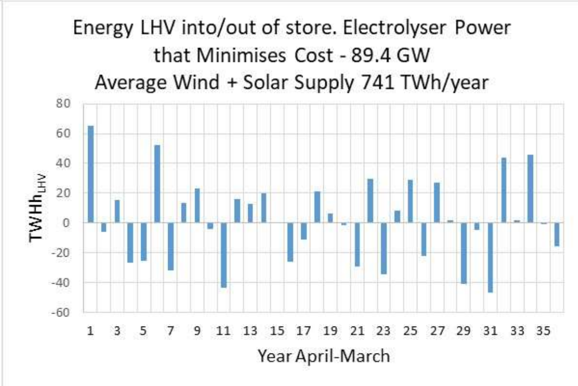
With averge wind + solar supply = 741 TWh/year, it is found (with the models used here) that it can meet an average of 485.0 TWh/year of demand directly, leaving 570 – 485 = 85.0 TWh/year to be provided by storage. With the assumed efficiencies, this requires an average of 85/(0.74 x 0.55) = 208.9 TWh/year of wind and solar power to be put into storage. There is therefore an averge residual surplus of 741 – 485.0 – 208.9 = 47.1 TWh/year. This arises because i) the initial surplus (wind + solar supply – demnd) is greater than the electrolyser power, and/or ii) the store is full – both components are plotted in Fig SI 3.1.

Figures 7 and SI 1.2 show quarterly surpluses and deficits at the threshold for wind and solar supply to meet a demand of 570 TWh/year over 37 years - in Fig 1.2 in the hypothetical (and unrealistic) case of 100% efficient stroge (so average annual supply = demand), in Fig SI 1.2 with the round efficiency 40.7% assumed for hydrogen with average supply = 703.5 TWh/year = 1.23 x demand. These figures give a feel for the time over which energy has to be accumulated and stored until used to meet demand.

At the threshold all surpluses must be stored, so very large electrolyser power is needed, and the store has to be extremely large. This was discussed in section 3.2.1 where it was shown (see Fig 12) that the size, and cost, of the storage system falls rapidly as wind and solar supply increases above the threshold. At the threshold of 703.5 TWh/year, 478.5 TWh/year of demand is met directly by wind and solar, while 91.6 TWh/year is met via storage, and there is no unused surplus. With supply of 741TWh/year, 485 TWh/year of demand is met directly, 85 TWh/year is met via storage, and there is an unused surplus of 47.2 TWh/year. With supply of 760 TWh/year (where the system cost is minimum with the relative cost of electrolysers and storage assumed in this report), the corresponding numbers are 488 TWh/year, 82 TWh/year and 70.6 TWh.

The size of the store and the period over which energy has to be stored depends on the electrolyser power that it available. Figs SI 2.1 show the difference in the level of hydrogen in the store at the beginning and end of years April to March with supply of 741 TWh/year for the cases with i) the lowest viable electrolyser power/largest store (at the front edge of the surface in Fig 12), ii) the largest usable electrolyser power/smallest store (at the back edge), and iii) the electrolyser power that minimises the cost with the relative costs of electrolysers and storage assumed in this report (on the red line).





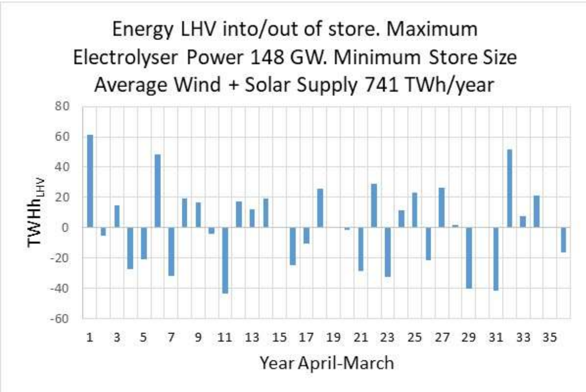


Fig SI 2.1 Net energy content of hydrogen stored (positive) or delivered (negative) by storage in years April to March. The relatively small difference between the cases with electrolyser power of 89.4 GW and 148 GW is due to the fact that both lie on part of the surface in Fig 3.1 which is almost flat.

The most time is needed to replenish the store in the case with the minimum electrolyser power, and more energy is stored for longer periods. In all cases, however, meeting the deficit in year 31 requires the use of some of the energy that was already in the store at the beginning of the 36 years studied (as can also be inferred from Fig12).

Fig SI 2.2 shows i) the 'effective' surpluses, i.e. the electrical energy that can be delivered by stored hydrogen (i.e. the wind and solar generated electricity that is stored multiplied by the round-trip efficiency of 40.6%), and the deficits that are filled by electricity provided by storage (which is equal to the energy content of the hydrogen withdrawn from the store multiplied by the efficiency of 55% with which is it assumed that electricity is generated), and ii) the residual surplus wind and solar generated energy that is available for other uses, or has to be curtailed, either for lack of electrolyser power or because the store is full. Note the extreme interannual variability of the residual surpluses.

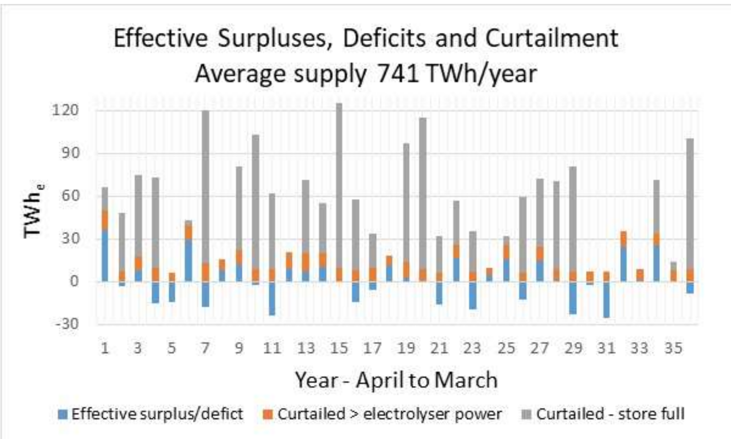


Fig SI 2.2 *The effective surpluses are the electrical energy that the surpluses that are stored can deliver taking account of the round-trip efficiency. The deficits are the electrical deficits that are filled by stored energy.*

3.3 Modelling and costing with several types of store

Scheduling

More details are given here of the method used to schedule the use hydrogen storage together with ACAES[v]. The method, which was outlined in section 3.3, is based on logic developed by Zachary et al [1].

The scheduling procedure determines, hour-by-hour, which type of store (hydrogen or ACAES) is charged preferentially and which is discharged preferentially. Maximum use is made of the preferred store: any residual that it cannot handle (whether due to limitations on power or on how much energy is already in store) is handled by the non-preferred store.

Decisions on charging and discharging take account of the current level of fill (F_0) and forecasts of supply and demand in the coming 12 hours. First, the level of fill at the end of 12 hours ($F_{12}^{assuming}$) is calculated *assuming* that ACAES has priority in charging and discharging (which is the default option for reasons described in the Report). $F_{12}^{assuming}$ is then compared to prescribed lower and upper threshold values X and Y, which depend on the round-trip efficiency, as shown in the table below. If $F_{12}^{assuming} > Y$, priority for storing energy (when needed) is given to hydrogen. If $F_{12}^{assuming} < X$, priority for dispatching energy (when needed) is given to hydrogen. This switching of priorities for charging/discharging tends to prevent the ACAES store from becoming either full or empty, which has the effect of keeping more of ACAES' capacity to store and absorb power available than would otherwise be the case, thereby reducing the need for the hydrogen store to do so.

ACES Round-trip efficiency	Lower Threshold, X	Upper Threshold, Y
45%	13.035%	88.319%
50%	12.149%	89.690%
55%	11.509%	90.608%
60%	10.992%	91.300%
65%	10.553%	91.852%
70%	10.167%	92.310%
75%	9.822%	92.697%
80%	9.509%	93.032%

Table SI3 4 Filling factors at which priorities for dispatching and storing power are switched

As stressed in the Report, more work in needed on scheduling, which could take account of detailed forecasts over longer periods (they are now quite accurate for up to a week), and of seasonal forecasts (which are becoming increasingly accurate). It would also be worth exploring the effects of allowing the switching point to depend on costs as well as efficiencies, and of sharing priority between the stores in a prescribed way in some cases.

[v] The multi-store modelling used in this Report was carried out by Seamus Garvey.

ANNEX SI3 1 MIT Report - The Future of Energy Storage

The 387-page MIT report[34] goes into more detail than this report on some topics e.g. in the impressive discussions of thermal storage and the physics of ACAES, and there are large areas of agreement in the discussion of storage technologies and their potential. However, the scopes of the reports differ and much of their modelling is focussed on near-term/mature energy storage technologies. Also, there is apparent disagreement on the costs of power ↔ hydrogen storage and ACAES, which play prominent roles in this report. Finally, MIT use sequences of weather data that this report finds would be far too short to estimate storage needs reliably in GB. As a result, the MIT report comes to quite different conclusions on both the scale and the type of energy storage technologies that will be needed.

Scope – This study is focused on the possibility of wind and solar supported by energy storage providing all Great Britain's electricity in 2050, without and with some zero-carbon baseload supply, without relying on imports. The MIT report, which is primarily focused on the North East and South East USA and Texas, allows for: various low levels of carbon emissions in 2050 (including zero), imports and exports from other regions (except in Texas), and a wide range of sources, including hydro in the NE and SE (hydro is not considered in this report as its potential role in GB is limited).

Hydrogen Storage –

- **Electrolysers** – in modelling, MIT use their mid-range projection of \$479/kW for the 2050 cost of PEM electrolysers, in reasonable agreement with the value of \$450/kW assumed in this report (without specifying PEM or Alkaline).
- **Underground storage** – the mid-range cost assumed by MIT is for caverns that can each store 500 useable tonnes of hydrogen (Footnote 10, Chapter 5), whereas this report uses the H21 NE consortium's cost of (clusters of) caverns that store 3,695 usable tonnes each (with 50% added to the cost in the base case). MIT use the cost given by Ahluwalia et al[33], who find that it varies as (mass stored)$^{-0.52}$. Allowing for this variation, the apparently very different costs are in reasonably good agreement. Surprisingly, however, in modelling storage MIT use the estimated cost of above ground storage, which is six times higher than their estimate for underground storage, which in turn is twice as big as the base cost used here for very large caverns.
- **Conversion of hydrogen to electricity**. MIT conclude that combined cycle turbines will the cheapest method of conversion in 2050. This report finds that both four-stroke engines (which MIT did not consider) and fuel cells will be cheaper. MIT find a mid-range [low] 2050 cost of \$1,500/kW [\$950/kW] for PEM fuel cells. This is higher than the cost (of \$650/kW) found by stripping out the cost of handling natural gas and reformation from Battelle's bottom up costing of methane fuel cells. This cost (see SI 4.5) could be reduced to \$425/kW by optimisation for the use of undiluted hydrogen, which is IEA's 'optimistic' value for 2030 that is used for conversion in 2050 in this report, which finds that four-stroke engines could be 30% cheaper. \$425/kW is in the range \$(340-528)/kW for the future cost of PEM cells given in an NREL report by Hunter et al[10].

ACAES – The MIT report finds that *with underground air storage [ACAES] seems viable and in some regions … may play a non-trivial role in the future***.** However, having noted (as done repeatedly in this report) that cost estimates for ACAES are subject to multiple uncertainties, MIT do not include it when modelling storage. In this report, encouraged by the fact that three

ACAES plants were connected to the grid in China in the period September 2021 to September 2022, ACAES is modelled as an exemplar of a class of storage technologies with much higher round-trip efficiency than hydrogen storage, on the basis of more optimistic assumptions about its potential efficiency and cost:

- **Efficiencies.** MIT assume a round-trip efficiency of 58.8%. In this report it is noted that bespoke compressor and expander designs optimised for ACAES will be required, which could give a round-trip efficiency greater than the 68% assumed in this report (in which results are also given for lower, and higher, efficiencies).
- **Cost of compressors and expanders.** MIT give a range $(813-1,069)/kW for the sum of the 2050 costs of compressors and expanders with power ratings and configurations (single or multi-stage?) that are not stated. While this is compatible with the range of up to £500/kW for the full cost of compressors and expanders separately assumed in this Report (based on an estimate of the cost of large multi-stage compressors provided by a leading manufacturer), comparison is not possible without more information on the power ratings (to which, as discussed in the Report, the cost is very sensitive) and design considered by MIT.
- **Storage cost.** As discussed in the Report, the storage costs assumed by MIT are much higher than those used here. MIT do not provide a breakdown of their cost estimates (which were based on five sources), but the lower costs found here are presumably a result of the assumptions that i) thermal storage is provided by water pits at a cost (based on the actual costs of systems in Denmark) of £0.12/kWh, rather than molten salts (for which e.g. Hunter et al[10] give low, mid and high future costs of $(16/21/27)/kWh$_{th}$), and ii) the compressed air is stored at very low cost in 300,000 m^3 solution-mined salt caverns.

Matching supply and demand - MIT use a Capacity Expansion Model that allows for multiple sources of supply. This sophisticated model matches available power and demand hour-by-hour assuming perfect foresight, which (with the other assumptions fixed) leads to a lower bound on the storage capacity that would be found without perfect foresight. The model allows for occasional 'non-served energy' events when demand is not fully met. The model on which the conclusions of this report are based is less sophisticated (e.g. unlike the MIT model it does not take account of grid constraints), but is relatively transparent: it schedules the use of several types of stores in a way that does not rely on perfect foresight (therefore providing values of storage capacities that could in principle be reduced), and ensures that demand is always met.

Modelling the weather and the need for storage – For the NE and SE USA, MIT studied composite weather years made up from '5 representative periods of 10 days from 2007–2013 weather years, including "extreme" periods'. For Texas they studied the continuous 7-year period 2007–2013. One of the major conclusions of this study is that (as found by others) studying short apparently 'representative' periods is liable to seriously underestimate the need for storage (even 37 years is not enough to provide a representative sample of rare weather events in GB). This suggests that MIT may have underestimated the required storage capacities. Their estimates are proportionately much smaller than found in other studies cited SI 3.1. MIT considered powering Texas with only wind and solar supply supported by batteries. They found that demand could be met with average wind plus solar supply equal to 2.1 x average demand, and a storage capacity able to meet 12 hours of average demand (7 hours of peak demand). This is much less than found in this report for GB with only wind and solar supply. Part of the difference can be accounted for by the high level of wind and solar supply assumed for Texas (this report does not consider cases of supply much larger than 1.3 x demand), the higher volatility of wind and solar supply in GB (where wind dominates, whereas solar contributes more than wind in Texas), and the fact that batteries can be charged much more rapidly than a hydrogen store, so a smaller storage capacity is needed. It may also be partly due to the use of only seven years of weather data.

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Annex SI3 2 AFRY Report

Recent UK Long Duration Renewable Energy & Storage Studies by AFRY

Studies & Modelling

The energy consultancy AFRY have recently completed three studies related to long duration energy storage that address the same problem as this report. They were for BEIS[35] on energy storage with longer durations than 4 hours, National Grid (ESO)[36] on system adequacy and the Climate Change Committee[37] [38] on system design options for 2035 and 2050. All used AFRY's BID-3 economic model which includes most of Europe and the UK. Demand and supply from multiple sources are modelled for one year of weather and demand data with, the aim of minimising capacity and energy costs. Several different single years of weather are considered to establish the effect of the worst year. Only a few short extreme weather events that severely reduce renewable supply are considered. Also, the supply and storage costs assumptions are not transparent and there are no future energy costs comparisons for the scenarios studied, which is odd for what are economic analyses.

Results

The Climate Change Committee study is typical. It includes both the power sector and the market for hydrogen for heat and industry (assumed to be 200 TWh). By 2050 variable renewable capacity is 252 GW (wind 146 GW solar 106 GW, generating 620 TWh) with at least a further 150 GW of additional supply and flexibility (potential supply 250 TWh) - capacity in total more than 5.5 times mean demand.

Energy storage volumes for 2050 are 90 GWh grid storage - batteries plus physical system (mainly less than 4 hours) plus 8 TWh of hydrogen. Excluding 16 GW of unabated supplies, grid storage needs would increase to 120 GWh plus 15 TWh of hydrogen. For lower cost medium duration grid storage, needs increase to 1,300 GWh (now mainly over 12 hours). Only if blue hydrogen is replaced by green hydrogen generated using excess renewable electricity that is not exported, can carbon emissions be reduced below 8 Mtne per year.

Review

The results of these studies are different from those in this report for four main reasons:

- Modelling is only of a single year of weather, with some consideration of more extreme weather events. These short-term studies seriously underestimate the need for energy storage, however provided. Conversely, they overestimate the need for other forms of flexible supply.
- While there are solid economic arguments for interconnectors to Europe, depending on them for Grid reliability is risky. Some weather events will affect a large part of Europe impacting their renewable supplies. Also, this strategy depends on the continuity of supplies from other countries under all circumstances.

- The approach to system planning is incremental rather than considering system needs for 2050. Large amounts of the currently available batteries and CCGT & CCS are built. As a result, the plans include significant capacity that may not be required in 2050, or may not be economic. System costs in the period 2040-50 will be higher than otherwise.
- Natural gas is used as the main means of providing flexible supplies using either CCGT & CCS or blue hydrogen turbines, rather than green hydrogen storage. Emissions in 2050 remain at 8-10 Mtne pa, a level that will probably be incompatible with net-zero for the whole economy in 2050, where other more difficult requirements will have priority for the very limited residual carbon emission allowance.

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SI 4 Green Hydrogen and Ammonia as Storage Media

4.1 Introduction

Box SI 4.1 Thermal Energy Content Calorific and Heating Values

In this report the thermal energy content, or **equivalent calorific value,** of a substance is generally quoted in terms of its **lower heating value (LHV). LHV** is defined as the amount of heat released by combusting a specified quantity, initially at 25°C, and returning the temperature of the combustion products to 150°C, assuming that the latent heat of vaporization of water in the reaction products is not recovered. Manufacturers of turbines, fuel cells and electrolysers normally define their efficiencies in terms of the lower heating value of the fuel consumed, or produced.

The upper (or higher) heating value of a fuel is also used for some purposes. It is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to 25°C. It includes the latent heat of vaporization that is released when steam condenses. Since not all combustion devices can take advantage of this latent heat, it has become conventional to define efficiencies in terms of lower heating values. However, in some regions, such as the US and the UK, natural gas is sold by its higher heating value.

4.2 Hydrogen and Ammonia Production

Electrolysers

The output of electrolysers scales with the surface area of their anodes and cathodes. Large-scale production is achieved by using systems composed of multiple modules – allowing redundancy, decreased down-time and also the opportunity for relocation as the modules are relatively easy to move. Use of multiple modules increases the rate of learning in manufacturing, allowing roll-out of incremental improvements. Because electrolysis is an area-based process, the cost per unit capacity does not fall as quickly with increasing scale as conventional process plant (which scales volumetrically), so electrolysis does not offer the usual economies of scale that can be accessed with more traditional process technology.

There are four types of water electrolysers, whose main characteristics are summarised in Table SI 4.1. The output pressure can be increased in alkaline and PEM cell electrolysers by pressuring the water, up to 30 bar in the alkaline case[1] (higher pressures lead to crossover through the diaphragm that causes contamination), and 50 bar[2] or higher in the PEM case. In the solid oxide case, no simple way to increase the pressure is currently known.

Particular features of different types of electrolysers, and projections of their costs and performance, will now be discussed in turn. The discussion draws heavily on reports by IRENA[3] (see also an IRENA review of patent applications[4]) and the IEA[5], which are based on their own analysis and reviews of the literature, and discuss avenues for improving performance. Their cost estimates include not only the stack, but also balance of plant, rectifiers, the hydrogen purification system, water supply and purification, cooling and commissioning – but usually exclude shipping, civil works and site preparations. Avenues for

Table SI 4.1 Types of electrolysers	**Alkaline**		**Polymer Electrolyte Membrane**		**Solid Oxide**		**Anion Exchange Membrane**
Availability	Commercially available for many years*		Commercially available but potential for improvement		Not yet demonstrated at scale		Beginning to be available commercially
Load Following	Can load follow		Can follow v fast transients < 1 sec		Ability to load follow depends on the design		Can load follow
Electrolyte/ membrane	Sodium, or potassium hydroxide		Aqueous electrolyte polymeric membrane		Oxygen ion conducting ceramic, typically zirconia (ZrO2) based		Typically potassium hydroxide electrolyte and anion conducting membrane
Largest current module	5 MW (~ 2.1 tonnes)/day[6]		2 MW (> 0.9 tonnes/day)		0.225 MW[6] (0.14 tonnes/day)		1MW (450 kg/day)[7]
Operating temp	60 to 90°C		50 to 90°C		Zirconia-based designs > 700°C. Ceres steel backed cells - somewhat lower		55 ^{0}C
	IRENA[3]	**IEA[5]**	**IRENA**	**IEA**	**IRENA**	**IEA**	**IRENA**
Efficiency Today*	43-67%	63-70%	40-67%	55-60%	61-74%	74-81%	Today 57-69%
2050 (IRENA)/ Future (IEA)	> 74%	70-80%	> 74%	67-74%	> 83%	77-90%	
*LHV of procued hydrogen/electrical energy input - includes rectifier losses							
Cost $/kW Today**	500 - 1000	500 - 1400	700- 1400	1100 – 1800	> 2000	2800 - 5600	
2050/Future	< 200	200- 700	< 200	200- 900	< 300	500 - 1000	
**Full system costs. Ranges depend on scale of manufacturing and size of module – see text. In their simulations, IEA assume a future cost of $450/kW and an efficiency of 74%							
Lifetime today 1000 operating hours	60	60-90	50-80	30 -90	< 20	10-30	
2050/ Future	100	100-150	100 -120	100 - 150	80	75-100	
Output Pressure – bar. **Today**	< 30	1 - 30	< 70	30-80	< 10	1	Up to 35 bar
2050/ Future	> 70	-	> 70	-	> 20	-	

cost reduction include automation and scale-up of manufacturing, improvements in design and reductions in the use of expensive materials (for example titanium, platinum, iridium in PEM fuels cells), and drawing on some of the innovations made by the chlor-alkali industry. Manufacturing costs will be reduced as these technologies are adopted at scale, as a result of standardisation and modularisation, and adoption of high-volume production methods such as laser cutting, plastic injection moulding and automated assembly

Alkaline Electrolysers

Although alkaline electrolysers have been in use since the 19th century, there is limited experience of operating them with the sort of variable loads that are produced by wind and solar energy. Frequent switching on/off could corrode the electrodes. Experts are confident this can be avoided by a suitable choice of materials and/or applying a small voltage, and recent results appear to support this[8], although it awaits full experimental confirmation. Operating with a variable current would be expected to weaken the membrane, but with the scale of storage envisaged in this report, large numbers of electrolysers will be employed (perhaps or order a thousand 100 MW devices). A variable total load could therefore be accommodated by operating individual electrolysers, when they are switched on, with a constant current with a value that provides a good compromise between efficiency and lifetime (this would also deal with the problem that electrolysers must be operated above 20% of the design current in order to avoid cross-over producing a potentially explosive mixture of hydrogen and oxygen). Alternatively supply could be buffered by adding a battery.

Alkaline electrolysers cannot respond to very fast transients, and may take up to 30 mins to start up, but once operating within their normal operating window, they are sufficiently flexible to follow fluctuations in wind and solar power[3]. It takes time to start them from cold, but with a fleet of electrolysers some could be kept warm when switched off if necessary, and forecasts of wind and solar supply and electricity demand could be used to schedule their use.

IRENA's summary table gives the 2050 cost projection of under $200/kW in 2050 shown above, but this depends on the size of the modules and scale of production. They state that a 20 MW module would cost 33% less than a 1 MW module (typical of the scale today), and in one plot project a further drop of some 30 % when going from 20 MW to 100 MW, with diminishing returns as the size gets larger. Their estimates of the dependence on scale rely on learning curves based on past experience, which give $307/kW and $130/kW for cumulative production of 1 TW and 5 TW respectively. A recent US DoE report[9] gives an installed (as very clearly stated below Fig 2) electrolyser costs of $425/kWe for 2030. After allowing for contingency (20%) and additional costs for offsites, and owners costs (20%), this would give $612/kW in 2030. Given the scale of the electrolyser power that is likely to be installed by between 2030 and 2050 and the consequent fall in the cost, and the cost ranges given the IEA and IRENA, this supports the use of $450/kW as the 'base' cost of electr;ysers in 2050.

The footprint of a 1 GW plant would 10-17 ha[10].

Polymer Electrolyte Membrane (PEM) Electrolysers

PEM electrolysers currently use both platinum and iridium as catalysts. The availability of Pt is discussed in the fuel cell section below. Iridium supply and cost is a concern that has been highlighted recently[11]. Supply is quite inelastic as it is a by-product of the production of higher volume platinum group metals including Pt itself. Currently, world Ir demand is in the region of 7,900 kg/yr[12] and it takes 400kg to produce 1 GW of electrolysers[13]. Ir loading is expected to fall (perhaps by as much 80% by 2030 according to Johnson Matthey). Without a large decease, PEM electrolysers will not be able to provide a major fraction of the electrolyser capacity foreseen in this report (assuming that other countries also wish to expand the use of PEM cells. Reducing or eliminating the need for iridium should be a high R&D priority.

IRENA expect the cost of PEM and Alkaline electrolysers to converge in the future when they are manufactured at very large scale, and do not distinguish between them in discussing 2050 costs. The footprint of a 1 GW plant would 8-10 ha[10].

Solid Oxide (SO) Electrolysers

SOEs have not yet been demonstrated at scale, so their future costs and performance are restively hard to predict. They are fed by steam (which could be provided electrically or by waste heat) which leads to higher efficiency than for low temperature alkaline electrolysers (at low temperatures the [LHV] efficiency, used here, cannot exceed 85% as the latent heat of water must be provided to produce steam and drive the reaction). In one example (Ceres Power PLC), the cells with ceramic layers are supported by steel, and operate at somewhat lower temperature that unsupported cells and can withstand many on-off cycles. Unsupported designs generally need to run at constant load. It is best to operate at a constant power point so thermal equilibrium is maintained. Several companies[14] are planning to scale up solid oxide electrolysers.

SOEs have the major advantage that they can be operated reversibly – as electrolysers when there is surplus wind and solar power, and as fuel cells when there is a deficit. This provides a cost advantage for storage that probably more than offsets the fact that they produce hydrogen at ambient pressure.

Anion Exchange Membrane Electrolysers

AEM are beginning to be commercialised, e.g. by Enapter AG who have one manufacturing facility in Italy and are about to open another in Germany. They use a polymeric anion exchange membrane and a dilute alkaline electrolyte. They provide some of the advantages of PEM (relatively high purity and flexible operation once operating) with the use of more abundant materials (e.g. steel rather than titanium for plates) associated with alkaline electrolysers, and also to be able to use water of similar purity to that in alkaline electrolysers. Hence they are expected to have a lower capital cost compared to PEMs once production is at full scale. At this point, the technology has not been demonstrated at large scale, and there is less certainty around expected stack lifetime, although one OEM expects greater than 35,000 hours.

Concluding remarks on electrolysers in 2050

It is not clear which technology will dominate in 2050. Most of a group of experts whose views were elicited in a 2017 study[15] thought that in 2030 PEMECs would be best as a result of superior characteristics for intermittent operation, although ‘more manufacturing and operating experience is required before these characteristics lead to a commercial advantage’. Others thought AECs would remain dominant, and a few thought SOEC would be best, citing ‘superior efficiency when co-located with industrial processes, operational flexibility (co-electrolysis or reverse operation as a fuel cell) and potentially low capital costs due to low-cost materials. The optimal way to source electrolytic hydrogen at scale may be from a mixture of facilities that use different technologies, for example alkaline electrolysers when steady power is available and PEM electrolysers (which currently have higher unit capital costs) to provide additional flexibility and faster response to transients in the power supply). AEM technology also shows potential promise of the advantages of PEM and AEC technology.

Offshore Electrolysis

An example of the possible use of electrolysers directly coupled with renewable power is provided by the Dolphyn project[16], which proposes the generation of hydrogen offshore using PEM electrolysers co-located with wind turbines. This would maximise the use of available wind power and offers savings in electrical infrastructure, especially long-distance cables from the wind farm to the shore, assuming that such a plant would be designed only to export hydrogen. A hydrogen pipeline connecting the wind farm to the shore would have to be constructed, unless existing sub-sea pipeline infrastructure could be re-purposed. Comparisons of the cost of bringing hydrogen and electricity on shore depend *inter alia* on the relative costs of cables and pipelines and of installing and operating electrolysers on and off-shore, and the expected load factors on the cables and pipelines, which would have to be sized to handle the peak load. Generating hydrogen offshore could become economic if existing pipeline infrastructure can be re-purposed, electrolyser capital costs fall sufficiently from today and the wind farm is located beyond a critical distance from the shore. The critical distance is a function of electrolyser capital cost and the ability to re-purpose existing subsea infrastructure. Literature studies[17,18], and a preliminary analysis for this report, suggest that the distances to shore for possible UK offshore wind farms are unlikely to favour electrolysis offshore. However, a report for the Scottish Government found that hydrogen produced by a 500 MW onshore plant commissioned in 2028 would be 25% more expensive that hydrogen produced by a 16% more efficient 1000 MW offshore plant, equipped with electrolyser that cost 29% less per MW, commissioned in 2032[19].

Ammonia Production

A full report on the production, transport and storage of ammonia has recently been published[20], which includes information on its current use in fertilisers, together with a discussion of additional ways it could be used in the future, for example in shipping. Here the focus is on ammonia's potential as an energy store in support of the electrical grid.

The Haber Bosch process

Ammonia is today produced by the Haber-Bosch process, in which hydrogen and nitrogen are combined at high temperature and pressure in the presence of a metal catalyst. This is one of the most-widely deployed chemical processes and underpins the production of artificial fertilisers. A significant proportion of the feed gases remain unreacted and must be recycled after separation of the ammonia. When green ammonia is made from hydrogen produced electrolytically, an air separation unit is needed to provide nitrogen (If the hydrogen is produced by SMR/ATR this is unnecessary as air is introduced into the reforming process, thus supplying the necessary nitrogen).

Haldor Topsoe are developing a solid oxide electrolyser-based process which integrates hydrogen production, nitrogen production and the HB process. This has two advantages: it uses process heat from the Haber-Bosch process to reduce energy consumption in electrolysis, and exploits the solid oxide electrolyser cell configuration to produce nitrogen as one of the feedstocks. Assuming waste heat is available, they are targeting a 35% cost reduction.

It is difficult to break down project costs and use them to project the full cost of a system in which electrolysers and an ASU replace the reformers because the costs of individual plant sections are rarely available. Also, published costs for actual projects vary widely, partly because of regional cost drivers, and partly because each project requires different levels of infrastructure investment (for example brownfield vs. greenfield). To illustrate the difference, brownfield conventional gas-based ammonia projects with minimal infrastructure investment are expected to cost in the range of $900-1,100 per tonne ammonia per year, whereas greenfield projects with little or no pre-existing infrastructure are expected to cost in the range $1,300-2,000 per tonne ammonia per year[21].

There is relatively little recent data on large ammonia projects, but a set of three projects in the US Gulf Coast (USGS) region has been selected for analysis to try to isolate the cost of the Haber Bosch synthesis loop (Table SI 4.2):

Table SI 4.2 USA Gulf coast ammonia projects

Location	Ammonia output (million tonnes/ year)	Capital cost	Notes
Freeport, Texas[22]	0.75	$600 million	Including purchased hydrogen and nitrogen, the synthesis loop and some infrastructure, such as a hydrogen storage cavern
Texas City, Texas[23]:	1.3	$1 billion[24]	Including purchased hydrogen and nitrogen. Infrastructure for ammonia storage and marine export is within the project scope. In addition, a steam reformer to supply the hydrogen and ASU to supply the nitrogen to the ammonia plant is being built by Air Products for $500 million[25].
Waggaman, Louisiana[26]	0.75	$850 million	Including syngas production. If syngas production is assumed to be 25% of the project cost[27], then the synthesis loop + infrastructure cost would be ~$640 million, very similar to the Freeport project.

On this basis, $800 per tonne ammonia per year appears to be a good value for the current cost of the synthesis loop and associated ammonia infrastructure.

ASU costs for ammonia are discussed in various literature sources. A value of $100 per tonne ammonia per year is taken based on work by Morgan[28] specifically for the supply of nitrogen to green ammonia facilities.

Estimates derived from data supplied in a private communication by an industry source are in good agreement with these numbers on a USGC basis ($808 per tonne ammonia per year for the loop and $114 per tonne ammonia per year for the ASU), based on reasonable, but non-verifiable, assumptions on installation cost factors (four for the loop and two for the ASU), and project owners' costs (20%).

4.3 Transport

Typical costs of transporting hydrogen and ammonia by truck, rail ship and pipeline are shown in Figure SI 4.1(in the case of pipelines: gaseous hydrogen, liquid ammonia). For the volumes and distances that will be needed if hydrogen or ammonia are used extensively to store surplus wind and solar energy, it is clear that pipelines will be by far the cheapest option if transport is required.

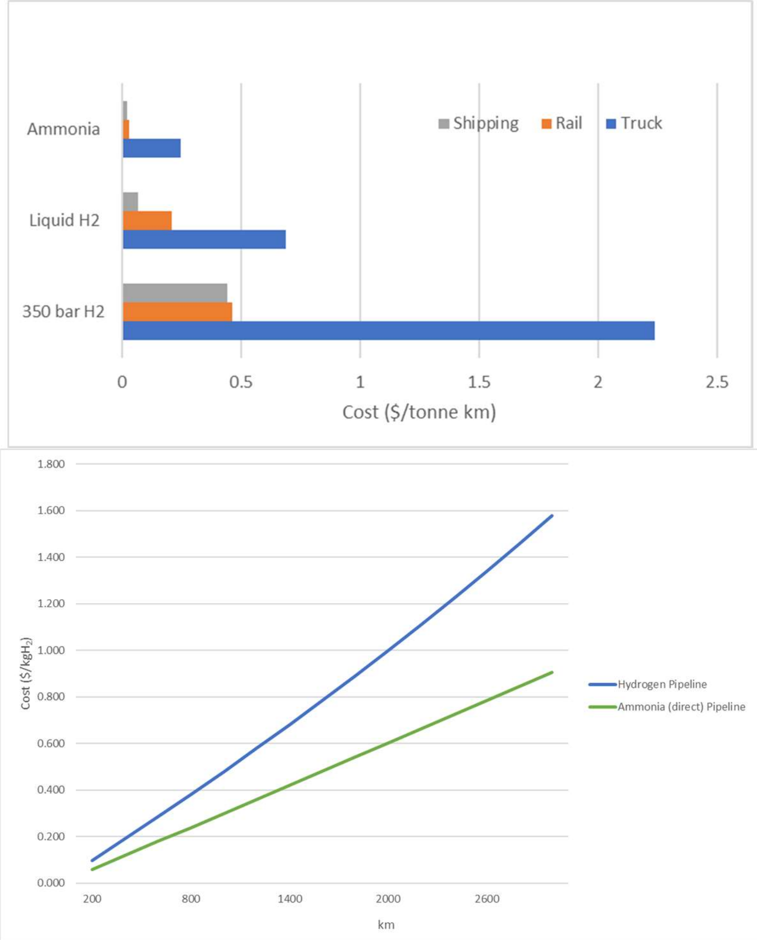

Figure SI 4.1 Cost of transporting hydrogen and ammonia by road, rail, shipping and pipeline. The top figure is expressed in kg of hydrogen content[29] (in which unit the energy content of ammonia is 88% of that of gaseous hydrogen). The cost/km of transporting ammonia by rail is about 1/15th that of transporting it by pipeline. The pipeline costs assume a 40-year lifetime, an 8% discount rate and a 40 cm diameter pipe, equipped with compressors every 250 km used 75% of the time.

The cost of using a pipeline to transport hydrogen that is produced by variable renewables,

The dicussion in this section is replaced by a note on Transmission of Electricity and Hydrogen which can be found at https://www.era.ac.uk/event/Royal-Society-largescale-energy-storage-event/ If pipes with the same capacity are used, the transport of hydrogen from stores to generators is nearly three times as expensive per mile as between electrolysers and stores because the maximum power that has to be transported is nearly three times as large. In the case that all power is transmitted by the hydrogen, the distance between electrolysers (adjacent to wind and solar farms) and stores will generally be much greater than the distance between stores and power generation (adjacent to the grid). The assumption that the same distance is involved in each case led to an unrealistically high estimate of the total cost in the original text on this page.

it should be possible to site electrolysers, stores and generators closer together, and/or reduce costs by using refurbished gas pipelines

4.4 Storage

Hydrogen storage

The British Geological Survey has recently published estimates of the potential hydrogen storage capacity in salt caverns in three onshore UK regions[30], building on earlier work[31]. The results, after eliminating areas occupied by towns, roads, railways, mine workings, waterways, rivers, canals, protected areas, geological faults, formation boundaries and areas of wet rockhead locations, are shown in Figure 16. The offshore potential of the East Irish Sea, Southern North Sea and Wessex basins, which were not evaluated in the BGS study, are likely to provide significant additional storage capacity. This could be used If a sufficient number of suitable onshore sites turn out not to be available, but the cost of cavern construction would probably be at least 50% higher than onshore. It could also be possible to store hydrogen in depleted gas fields, although this is untested, and the hydrogen would become contaminated making it unsuitable for use in PEM fuels without cleaning, which would incur further costs. The Rough field in the North Sea, which could store some 30 TWh of natural gas and was recently partially recommissioned in response to the European gas shortage[32]. If used to store hydrogen, as recently proposed by Centrica, it could accommodate some 10 TWh.

Maps of the distribution of salt deposits in the USA and Europe may be found in Ahluwalia et al[33], Bünger et al[34] and HyUnder[35].

As well as understanding what volume of storage could be available, it is important to know how fast it can be filled and depleted without threatening the integrity of the cavern. The maximum rates are governed by limits on flow rates in the boreholes and the maximum pressure reduction rates in the caverns, which are determined by local geo-mechanical conditions and operational requirements. Each development should be subjected to detailed studies to set limits on pressure changes. The salt caverns assumed here are of similar size to those studied in detail in the H21 North of England Report[36], which will be followed in assuming a maximum pressure change of 10 bar/day, corresponding to a withdrawal rate of 5.5%, with complete withdrawal at a lower average rate being possible in 30 days.

The cost of storing hydrogen in solution-mined salt caverns, depends on many factors including:

- The geology, depth, and geography, e.g. in a report for the Energy Technologies Institute[37] Amec Foster Wheeler found cavern costs varying from £26.8M for a 300,000 m^3 cavern at 1,800 m depth in E Yorkshire to £128.5 M for a 70,000 m^3 cavern at 370 m depth on Teesside, and the cost of pipes for transporting brine and water varying from £5.4 M for a cavern in E Yorkshire to £66.4 million for a cavern in Cheshire. Amec Foster Wheeler later provided very much lower costs for the H21 Leeds City Gate study[38], of which they were co-authors, based on wider experience. Their older numbers are only quoted here to provide a sense of how costs can vary with geology and geography.
- The size and pressure, e.g. a study by the Argonne National Laboratory for the US Department of Energy[33] found that the cost of storing between 50 and 300 tonnes of useable hydrogen at 150 bar varied as (mass) $^{-0.52}$ (according to a fit by Hunter et al43); in the range 10 to 190 bar, the cost of storing 500 tonnes was a minimum at 120 bar and only about 6.5% more at 70 and 190 bar (there is a trade-off: for a fixed mass, increasing the

pressure reduces the cavern size and the cost of leaching and brine disposal, but it requires more powerful hydrogen compressors and greater depth, which increases the cost of bore and production tube installation).

- What over ground equipment, management costs and contingency are included.

This report uses cost estimates made by the H21 N England consortium[36] for sites in E Yorkshire as i) it houses the best sites in GB, iii) the potential is large, iv) H21 NE builds on other studies of hydrogen storage in GB[38 39]. H21 NE, whose estimates, are compared to others below, based subsurface costs on experience from an operational gas storage plant at Aldbrough, and used quotations from suppliers to estimate the cost of critical equipment (compressors, heat exchangers etc). They include site preparation and services, management costs, brine disposal, and other costs, such as insurance, as well as some contingency.

H21 NE provide details of capital and operational costs for a system comprising ten 300,000 m^3 salt caverns, with a common surface facility, at depths of 1,700-1,800 m at up to 275 bar, which would each house 144 GWh_{HVV} of hydrogen (not including 70 GWh_{HHV} TWh cushion gas), in line with the individual volumes found by the BGS. The total cost of £325M (including £80M for subsurface work, which is used in the next Chapter to estimate the cost of caverns to store compressed air; £126M for the surface processing unit; £29M contingency, and £24M for cushion gas corresponds to £267/MWh_{LHV} for the useable 1.22 TWh_{LHV} (the paper reports results in terms of HHV), or £8.9/kg working gas. This is 78% of the cost found in the earlier Leeds City Gate Study of an 0.855 TWh system (which was led by the same project manager as H21 NE; the hydrogen system design was led by staff from Amec Foster Wheeler).

H21 North of England's surface unit includes three 8 MW compressors, three 750 ammonia (working fluid) refrigerators, and three 150 kW air coolers, which are designed to deliver hydrogen (provided at 80 bar, 20C at up to 38.1 t/hour) to the store at 275 bar, 20 C. The design, and cost, of the surface unit may have to be adjusted if hydrogen is provided in different conditions. It turns out however, that although it is assumed in this report that hydrogen is provided by electrolysers at 30 bar and over 50 ^{0}C, in the hydrogen storage only case the maximum rate at which it is delivered is much lower than allowed for by H21 NE, and the equipment costed by H21 NE would be up to the job[i].

The H21 NE Study assumes that O&M costs are 4% of capex (without the cost of the cushion gas). This is for a system that is cycled regularly, whereas the modelling of storage in Chapter 4 suggests a very low throughput/volume, and 1.5% of total storage capex is assumed here. Given the low cycling rate, a project lifetime of 30 years is assumed (although the cavern, which is responsible for 25% of the capital cost, will certainly last much longer). With these assumptions, the annualised capex plus £3.4/MWh for O&M is £21.4/ MWh_{LHV} storage capacity at 5% discount rate and £32.3/MWh_{LHV} at 10% discount rate.

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[i] M Muskett, private communication. The calculation uses https://h2tools.org/hyarc/hydrogen-data/hydrogen-compressibility-different-temperatures-and-pressures and takes account of the compressibility of hydrogen as a function of pressure. In the hydrogen storage only case, with 741 TWh/year of wind and solar supply the cost would be minimised at electrolyser power of 82.2 GW and a total store size of 123 TWh (including 20% contingency). In this case, 100 of the clusters of 10 caverns studied H21 NE would be required, and hydrogen would be delivered to each cluster at a rate up to 18.3 tonnes/hour, at 30-50 bar, 50+ C. A calculation of compression and cooling in three stages, benchmarked by showing that the equipment costed by H21 NE could deliver hydrogen (provided at 80 bar, 20 C at 38.1 t/hour as assumed by H21 NE) at 274 bar, 20 C, shows that it could also do so (with a 9% margin) with hydrogen provided by electrolysers at 30 Bar, 50C at the lower rate of 18.3 t/h.

The H21 NE costings can be viewed as effectively replacing the earlier Leeds City Gate and Foster Wheeler studies. Comparison with other studies of underground hydrogen storage in GB is not straightforward:

Jacobs/Element Energy report[40] costs that are qualified by the statement that 'for every kWh of hydrogen storage, 10kWh of salt cavern storage is costed'. With this qualification, their estimate, for storage in E Yorkshire at 250 bar, corresponds to £165/MWh_{LHV}. However, this cannot be compared directly with H21 NE's value of £267/MWh_{LHV} as the average cavern size of 1,126,000 m^3 was larger. Assuming simplistically that all the caverns had the average size and using the Argonne scaling law, the cost would be £347/MWh_{LHV}.

DNVGL[41] give a cost of £549/MWh_{HHV} (using an exchange rate of 1.18 €/£) for storage at 250 bar and a storage capacity of 5 PJ_{HHV} = 1390 GWh_{HHV}, close to the 1440 GWh_{HHV} in *ten* H21 NE cavern, at 275 bar. It is unclear why, with such a large volume (some 3 x 10^6 m^3 - larger than the biggest of the three salt caverns described above that store hydrogen in Texas, which has a volume of 906,000 m^3), DNVGL find a cost 2.4 times greater than H21 NE's estimate.

The Argonne study[33] gives costs for useable hydrogen stored at 150 bar up to 3,000 tonnes, which correspond to \$12.4/kg when extrapolated (using the fit reported above) to H21 NE's 3,695 tonnes, or £9.2/kg assuming an exchange rate of 1.35 \$/£, which is slightly above the H21 NE estimate. However, these estimates cannot be compared directly as i) the Argonne study of storing 500 tonnes suggests that the cost might be 15% more at the 275 bar assumed by H21NE than at 150 bar, and ii) the Argonne study does not assume economies from sharing surface facilities (although it suggests that for storing over 750 t useable hydrogen multiple caverns might be needed), while H21 NE costed ten caverns that share above ground facilities (which, with site services, management and miscellaneous costs, contribute 55% of the total, if the 10% contingency is all attributed to underground work; the Argonne study assumes 10 miles to brine disposal, while H21 NE costed a site some 8 km from the shoreline, with 10 km of onshore pipes and 4-5 km undersea (Henrik Solgaard Andersen, Equinor, private communication).

A Sandia National Laboratory study[42] of storage in a 580,000 m^3 cavern (for which it gave a cost per m^3 is quite close to the H21 cost) states that, allowing for 30% by volume cushion gas, it would house 1,912 tonnes working gas at 138 bar. However, a simple calculation gives 4208 tonnes, and dividing the total cost by this (rather than 1,1912 t) gives \$15/kg, which is 30% higher than the Argonne result, extrapolated to the same mass.

Many other estimates of the cost of hydrogen storage in the literature can be traced back to a few sources (e.g. the International Energy Agency's estimates[29] were taken from the HyUnder study[35]; those in the recent NREL study[43] were based on the Argonne study[33] and/or do not give enough details to enable comparison with the H21 NE estimates. A Hyunder report gives an estimate of €28M for construction of a 500,000 m^3 cavern in a top depth of about 1,000 m^3, including exploration, drilling, leaching, first fill and all other engineering and management work on a green field site (the length of pipes needed for brine disposal is not reported). The report says that *These costs are conservatively estimated and can vary immensely (€20-50M), depending on ... knowledge about the geology at site.* The bottom of this range corresponds to £34-85/m^3 (at an exchange rate of 1.2) which is just above H21 NE's £30/m^3. Taking account of the further statements that *costs are reduced when well-known salt structures … can be used ... Increased experience in hydrogen storage will also help to reduce investment* *costs,* and noting that the caverns studied by H21 NE will benefit from good conditions in E Yorkshire, and experience from Aldborough, while for storing electricity tens of facilities with 10 caverns/facility are likely to be needed, the H21 estimate is not incompatible with Hyunder's. Hyunder do not give above ground costs, but Bünger et al[34] quote a full cost of €107 M for storing 4 M useable tonnes of hydrogen in one of the caverns studied by Hyunder, which corresponds to £22.2/kg - well above the H21 NE estimate of £8.9/kg. The difference is not very surprising as their volume cost is 53% higher that H21 NE's, who however assume a pressure 52% higher than Hyunder, but model systems with shared above ground facilities.

In conclusion, H21 NE's cost estimates are

- similar to but a bit lower than those found by Argonne and Sandia;
- at the bottom of the range found by Hyunder for underground costs, but (in so far as the absence of details allows comparison) significantly lower for the whole system;
- allowing for the difference in volume, probably somewhat lower than Jacobs/Element Energy's estimate
- a factor of 2.4 lower than DNVGL's*.*

H21 NE's costs will be used as input hereinafter as they are for GB, and are based on experience at Aldborough and quotes from suppliers. However:

- estimates of underground costs are inevitably uncertain.
- costs have risen since H21 NE's estimates were published in 2018
- although the underground storage volumes that may be needed (for ACEAS as well as hydrogen) that are found in Chapters 4 and 5 are well within BGS's estimates of potential capacity, H21 NE's cost estimates may not be applicable at all the sites that will be used.

Consequently 1.5 x H21 NE's cost estimate is used as the central/base cost estimate in the report, and 1 x and 2 x H21 NE's estimate are used as the low and high values.

There is a need for further estimates of costs and potential capacities, in different locations, as a function of volume.

There is no particular reason to expect lower cavern costs in the future, although conceivably they could fall with learning if large numbers are constructed, and the cost of storage would be lower if constructing caverns substantially larger than those costed by H21 NE is practicable without a corresponding increase in the unit cost. Compressor costs are coming down and electrolyser output pressures are going up, and it might be possible to use air cooling of hydrogen (rather than an expensive refrigerator). It would, however, be rash to assume that the cost of storing hydrogen in 2050 will be lower than estimated by H21 NE, and the sensitivity to lower costs is not explored below.

Ammonia storage

Ammonia can be stored as a liquid, *either* under pressure (typically 10-15 bar depending on the ambient temperature), which is the cheapest option for volumes/masses up to about 5,000 m^3/3,000 tonnes NH_3[44], *or* at ambient pressures at -33°C for large scale storage. This study focusses on cold storage.

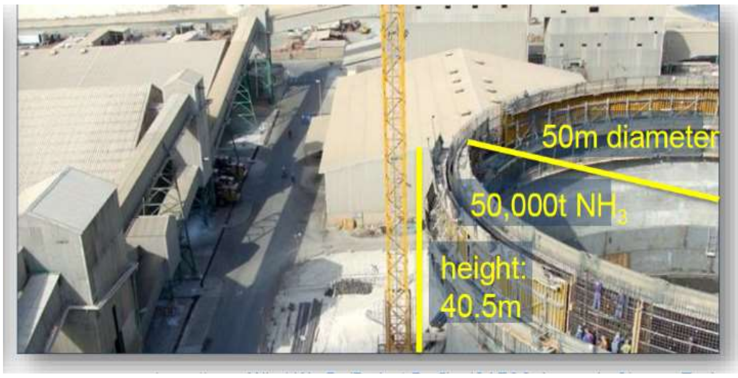

Figure SI 4.2 Ammonia storage tank in Qatar

Figure SI 4.2 shows a large low temperature ammonia storage tank under construction in Qatar. Little information is available publicly about the cost of such tanks, but a very well-placed source in the industry suggests that in Europe a 50,000 tonne tank would cost somewhere between €60 M and €90 M (the lower end for the tank and refrigeration compressor station only; the higher end with up to 1 km pipe and loading arm, but without jetty costs). The lower end of the range is equivalent to €232/MWh_{LHV} or £197/MWh_{LHV} with the exchange rate of €/£ = 1.18 assumed throughout the report. The H21 projection of £267/MWh_{LHV} for a fully equipped underground hydrogen storage facility (which is subject to much greater uncertainty than the cost of ammonia storage) is some 35% larger. The cost of O&M for ammonia storage must include the cost of the energy needed to re-liquify the 0.06%/day of ammonia boil-off, but this is quite small (for a 50ktonne tank, providing the latent heat of evaporation - 1.37 MJ/t - would require about 2 GWh/year, or around 0.1% of capex depending on the price of power). Assuming that the total cost of O&M is 1.5% of capex and the tanks have a lifetime of at least 30 years, as assumed for hydrogen O&M and storage, ammonia storage would cost €18.6 /MWh_{LHV} at a 5% discount rate and €28.1/MWh_{LHV} at a 10% discount rate using the LHV of gaseous ammonia[ii] and assuming a capital cost of €60 M for a 50,000 tonne tank. The rate of extraction of refrigerated ammonia is not a practical limitation.

4.5 Electricity Generation

Hydrogen Options

Hydrogen can be used to generate power in fuel cells (which are effectively electrolysers run in reverse), which produce just water, or by combustion, which also produces NOx. The focus here is mainly on generation of electricity to be supplied to the grid. The use of fuel cells to provide combined heat and power is considered briefly in SI 5. Other uses, for example of fuel cells in transport or to provide industrial heat, are outside the scope of this report, although they would help drive reduction in costs and provide flexibility and options in energy system operation and support economies of scale. The options that are available today are summarised in Table SI 4.3.

[ii] Although ammonia is normally transported and stored as a liquid, the appropriate value here is the LHV of gaseous ammonia (18.6 MJ/kg) assuming that ambient heat is used to vaporise the liquid thereby restoring the energy used in liquefaction (18.6 MJ/kg is often wrongly quoted as being the value for liquid ammonia, which is actually 17.2 MJ/kg).

Table SI 4.3 *Power generation options calculated from data in a US Department of Energy document* [45]

	Solid Oxide Fuel Cells	**PEM Fuel cells**	**4-stroke ICE**	**Open cycle Gas Turbine**	**Closed cycle Gas Turbine**
Fuel flexibility	$H_2/CH_4/NH_3$	H2 only	$H_2/CH_4/H_3$	$H_2/CH_4/NH_3$	$H_2/CH_4/NH_3$
Load following response	Seconds	Milli-secs	Secs	Secs	Secs
Capital Cost per kW [$]*	900	900	400	713	1084
Maintenance [% of capital p.a.]	1.0%	1.0%	3.0%	2.00%	2.00%
Lifetime [hours]	60000	100000	80000	80000	80000
Scale today [MW]	0.1-1.0	1.0	10 to 100	100	1000
Fuel to power efficiency LHV**	62%	55%	45%	34%	58%

*for H_2 with SOFCs, CH_4 or H_2 with 4-stroke ICEs, and CH_4 with OCGT or CCGT. The cost would be higher with other fuels, perhaps by 25% for 4-stroke ICEs designed to run on NH3.
**Efficiencies for turbines are often quoted in terms of HHV. LHV is used here for consistency with the electrolyser efficiencies quoted about, which (as is conventional) were expressed in terms of LHV. For electrolysers - HHV efficiency = 1.18 x LHV efficiency; for conversion - HHV efficiency = LHV efficiency/1.18.

The outlook for each technology will now be considered in turn. However, it is already apparent from Table SI 4.3 that - given that there will be a premium on low cost and high efficiency – OCGTs and CCGTs are unlikely to be favoured: their costs are unlikely to fall significantly as they are mature technologies, and hydrogen turbines, which should become available later in this decade, are expected to cost more (perhaps by 20%), at least initially, although this difference would fall if many were built.

Looking ahead, new technologies may of course emerge (e.g. high temperature proton conducting ceramic fuel cells, and reversible fuel cells, which also act as electrolysers) which could play an important role (both are discussed below). Fuel cell efficiency can be improved by 10-15 percentage points by using the oxygen co-produced by electrolysis, as it would allow the cells to operate at atmospheric pressure. This possibility has been considered for powering vehicles[46], and is being developed for power generation[47]. For energy storage applications, it would be necessary to store the oxygen, most likely as a liquid (underground storage of gaseous oxygen has been studied[48], but has yet to be demonstrated). Without thermal integration, the production of liquid oxygen for storage would carry a significant energy penalty, and potentially introduce some additional HSSE issues. Thermal integration increases the cost and complexity of the system. This is an area where further analysis is likely to be needed.

The conversion of stored hydrogen to heat and power may take place in distributed energy technologies. Nearly 300,000 residential micro-CHP PEM and SOFC fuel cell units producing up to 700 W_e each had been installed in Japan by the end of 2018. These systems use natural gas but would be substantially simpler (and cheaper) if operating on hydrogen directly. Storage systems that provide heat or heat and power are discussed further in Chapter 5.

Fuel Cells

According to the 2020 Fuel Cell Industry Review[49], 1,319 MW of fuel cell power generation capacity was sold in 2020, of which 968 MW was for transport (cars, trucks and buses) and 270 MW for stationary use, with almost all being PEMFCs (1,030 MW), Phosphoric Acid Fuel Cells (>100 MW) or SOFCs (148 MW). The PEMFCs are predominantly pure hydrogen fuel power units used in transportation whereas the Phosphoric acid and SOFC systems are nearly all designed to convert either natural gas or biogas into hydrogen which is then used in the fuel cell. Interest in cells that are powered by pure hydrogen for stationary power production is increasing rapidly.

Fuel cells which make direct use of hydrogen can be significantly simpler and smaller. Where these characteristics are important, as in powering cars, direct hydrogen fuel cells are favoured despite the high comparative costs of hydrogen. A review for the Department of Energy[50] found that the cost of 237 kW stacks, designed for use in heavy goods vehicles, produced at a scale of 20 GW/year could fall to $86/kW. This projection covers the core stack cost (some additional cost will be incurred for stationary power generation), but nevertheless provides some support for the cost estimates for large-scale power production by hydrogen fuel cells presented below, although they will be designed for different purposes and operated in different conditions.

In anticipation of falling hydrogen costs, automotive manufacturers (for example Toyota) are investigating producing fuel cell powerplants based on vehicle technology (each stack is 114$kW_{e,peak}$)[51]. The largest module size/stacks of fuel cells currently available are at the 0.25 MW scale, with multiple stacks/modules used as building blocks to increase the power. This smaller scale is likely to continue in the near-term to maximise cross-benefits between transport and power, but as potential markets for stationary fuel cells grow, larger stack sizes will be produced, potentially increasing power output by a factor of ten.

Three types of fuel cells are widely used today, none of which are currently deployed for grid scale projects:

- **Hydrogen Proton Exchange Membrane (PEM) Fuel Cells,** which convert hydrogen and oxygen from the air to electricity, water vapour and heat. A catalyst consisting of platinum nanoparticles, coated on carbon paper or cloth, facilitates the reaction of hydrogen and oxygen in a ‘cell’. These cells are combined in stacks that are embedded in modules that include fuel, water and air management, coolant control hardware and software. They have high efficiency (today typically 55% for power application) and are increasingly used to power cars, buses, forklifts, etc, as well as to provide backup power for the grid[52, 53]. Automotive applications differ from stationary power applications in two major ways: the cost is lower because the automobile applications have much lower balance of plant costs - a review for the US Department of Energy (DoE)[54] found that the cost of 237 kW stacks, designed for use in heavy goods vehicles, produced at a scale of 20 GW/year, could fall to $86/kWe; the system efficiency is lower because of vehicle power train losses.

  Hydrogen powered cells designed for use in power generation will be more expensive as they will not be manufactured at such a large scale, balance of plant costs have to be added, and they will have to satisfy different demands (on operating point/power rating, power electronics, and stack material loading). In anticipation of falling hydrogen costs, automotive manufacturers (for example Toyota) are investigating producing fuel cell powerplants based on vehicle technology (each stack is 114$kW_{e,peak}$)[55]. DoE estimates that 10 MW systems manufactured at a rate of 10,000/year would cost $600/kW today, and has set a 2030 target of $550/kWe. Projections of the long-term cost include those made by:

  Wei et al [56] who found a cost of a little over $500/$kW_e$ (including a 50% mark-up, and installation costs) for 10 kW power back-up systems manufactured at a rate of 50,000/year.

The US National Renewable Energy Laboratory (NREL)[43], which projects future low/medium/high costs of \$340/425/528/kW$_e$ (including 50% mark up and 25% for installation), based on stripping out natural gas reforming costs from a breakdown of a bottom up estimate of the cost of natural gas-powered fuel cells manufactured at a scale of 50,000/year[57], and assuming learning rates based on past experience.

The International Energy Agency[29], which states that 'on optimistic assumptions, Capex [it is implied for a full system] for hydrogen fuel cells may fall to \$425/kW$_e$ by 2030'.

On the basis of this information, in costing storage a base value of \$425/kW$_e$ is assumed for the full/installed capital cost of whatever is used to generate electricity from hydrogen in 2050, assuming large systems deployed at scale. A bottom of range cost of \$300/KWe is assumed, on the grounds that alternative means of power may be cheaper (and the much lower costs found for fuel cells designed for use in vehicles), and a top of the range value of \$425/kWe + 50% (and the effect of higher values will be reported). A financial lifetime of 30 years is assumed (typical projections in the literature are of lifetimes of 80,000 cycles, corresponding to a much longer calendar lifetime given that the load factor on power generation is only 10% in the all hydrogen storage scenario[iii]), an efficiency of 55%, and an operation and maintenance cost of 1.5%/year of the capital cost.

The use of PEM fuel cells for power generation will not be limited by the availability of platinum. Assuming an aggressive, but not unbelievable, loading of 0.1g(Pt)/kW, it would take 100 t of platinum to build fuel cells with a capacity of 1 TW. The world's current average power consumption is 3 TW. The Pt inventory for fuel cells would build up over decades and should be manageable in the world market, which stands at ~250 te Pt/yr[58]. The possibly very much larger use in vehicles has been studied by Han Hao et al [59] who find that "*although platinum-group metals are not likely to be a constraint for the mass deployment of fuel cell vehicles at the global level, there could be significant supply risks due to resource location. Reducing platinum loading of fuel cells, increasing platinum recycling rates, and improving the reliability of the platinum supply chain are appropriate measures to address such risks*." Some uses of platinum, such as catalytic converters for internal combustion engine vehicles are likely to decline in the long term, creating additional potential capacity for other purposes.

- **Phosphoric Acid Fuel Cells (PAFCs),** which operate at 180°C, are well developed, and have been optimised to use hydrogen from natural gas/biogas. They have demonstrated long lifetimes, but they depend on higher platinum loadings than those in PEMFCS and are therefore likely to have higher initial capital costs. The relatively low electrical efficiency of PAFCs makes them best suited to CHP applications, where the waste heat can be used to provide hot water leading to ~80% efficiency.
- **Solid Oxide Fuel Cells (SOFCs)** in which the electrolyte is a hard, non-porous ceramic compound. They do not need a precious-metal catalyst and they operate at up to 1,000°C. They are best suited for stationary applications and can use a variety of fuels (methane, hydrogen and ammonia, the latter so far demonstrated only at lab scale[60]) which are

[iii] The deterioration of fuel cell performance with use is ignored in costing storage in this report. It only has a small effect on their net present value because the fade rate is small (very small with the load factor of 10% found in the all hydrogen storage case) and later years when fade could become significant are discounted.

generally converted internally to hydrogen. SOFCs are around 60% efficient on natural gas, although this could be increased to 85% or more by using waste heat. Lower-temperature SOFCs (e.g., at or below 700°C), which would suffer fewer durability problems, especially if frequent load changes are required, are in the process of manufacturing scale-up today[61, 62]. There is a significant potential for cost reduction as the technology is relatively immature and the materials are inexpensive and widely available.

In contrast to PEM cells, whose output can be varied rapidly, high temperature SOFCs are best suited to relatively steady operation in order to avoid thermal gradients. Given their different characteristics, it may well prove desirable to deploy a mixture of PEM and SOFCs If fuel cells are widely used to generate power.

SOFCs are at an earlier stage of development than PEM fuel cells and less information is available on which to base future cost projections. However, SOFCs that operate at or below 700°C could well become competitive with, or cheaper than, PEM cells in the future as manufacturing scales up, and (as discussed below) have the potentially major advantage that they can operate reversibly, as fuel cells or electrolysers.

High temperature proton conducting ceramic Fuel Cells, in which solid state proton conductors[63, 64] replace materials that require liquid water to conduct protons, are at an early stage of development. They operate at > 200°C, thereby avoiding the problem of heat rejection which affects low temperature polymer electrolyte fuel cells, and allow better tolerance to contaminants in the hydrogen fuel. Direct use of ammonia has been shown[65]. They would also offer the ability to use catalysts based on more ubiquitous materials. The proponents believe that by 2050 they could be cheaper and more efficient than lower temperature PEM Cells.

Three variant fuel cell configurations deserve discussion:

1. **Reversible fuel cells** that would act as electrolysers when wind and solar power are in surplus, and as fuel cells at times of deficit, which would be very attractive. It is not at all obvious that reversible PEM cells would be cheaper than separate electrolysers and fuel cells, which normally use different catalysts. However, reversible SOFCS have been shown to work[66] and the US Department of Energy has recently allocated a total of over $16 M to six groups that are developing them[67]. The current density required of the units in electrolysis mode for long term energy storage is considerably lower than the current density in fuel cell mode, so there is more than adequate electrolysis capacity available, thus avoiding significant capital costs by avoiding the need for separate electrolyser units. For a fixed unit, the power demand in electrolysis mode would be about twice the power output in fuel cell mode. In the conditions discussed in Chapter 3, where it was assumed that there will be enough power output to meet demand, there would be enough electrolyser power to store all surpluses, and the hydrogen store could have the minimum possible size, prior to the addition of contingency. The additional capital cost of adapting a solid oxide fuel cell to allow reversible operation is estimated to be about 30%. The advantages of reversible SO fuel cells have to be set against the fact that in electrolyser mode they produce hydrogen at ambient pressure, so more compression power would be needed prior to storage than with electrolysers that produce hydrogen at higher pressure.

2. **Flexibly-fuelled fuel cells** could operate with hydrogen or with natural gas were hydrogen stocks to fall low. Methane fuel cells, in which methane is first broken down to hydrogen, could easily switch between using methane and using hydrogen supplied externally. However, the need to reform methane makes them more complex and

expensive. For PEM cells the premium for being able to use either fuel is large (as can be seen by comparing Battelle's 2018 estimate of $1,800/kW for a 100kW methane fuel cells with the much lower value found above after stripping out the methane stage). The premium is expected to be much smaller for SOFCs (perhaps 40%, or less for cells fuelled by a hydrogen methane mixture) because the higher temperature allows a cheaper catalyst to be used to break down methane.

3. **Methane** (natural gas) **fuel cells** coupled **with CCS**, which could also play an important role (albeit not directly related to storage) as efficient low (but not zero) carbon sources of power. High capture rates should be possible as the CO_2 stream would be relatively concentrated at ~95% by volume on a dry basis (although contaminated with CO and unreformed methane, which may require separation and recycle), and they could be operated flexibly[68].

Combustion

A recent study[69] concluded that **hydrogen gas turbines** (GT's) could be scaled to produce 1 GWe and operate flexibly. Today GT's that operate on pure hydrogen only support very specific applications, although it is expected that they will be available for more flexible, commercial applications by the end of this decade.

There is a range of GT systems in development that are designed to work with mixtures of fuels, e.g. 89 mol% H_2 and 53 mol% H_2 (typical of the outputs from an Auto Thermal Reformer and a biomass/coal gasifier for natural gas respectively).

Hydrogen burns at a higher temperature than methane, producing more NO_X without high levels of exhaust gas re-circulation leading to new challenges which increase as the percentage of hydrogen increases. Most high hydrogen concentration units can operate with steam added to the fuel, which reduces the reactivity and temperature of the combustion zone. This mitigates the production of NO_x[71], and reduces the hydrogen flame speed[70] which should improve stability.

Super lean conditions (with a very low hydrogen/air ratio) are also under consideration, although they will not enable the use of hydrogen concentrations close to 100%. Developing materials and new combustor designs that will allow higher hydrogen concentrations, eventually approaching 100%, is a priority for the European Turbine Network, to which most UK manufacturers belong[71].

It is expected that turbines that operate with pure hydrogen will be available by the end of this decade[71] [72], although in order to keep NO_X emissions below 60 ppm some post-combustion mitigation[71] is likely to be required. According to the BEIS scenario calculator dataset, combined cycle turbines that use pure hydrogen should operate with efficiencies in the high 50% range. Compared to turbines that burn natural gas, hydrogen gas turbines will have different combustion, control, fluid, and fire & safety systems, and will be up to perhaps 20% more expensive, according to an industry source.

In principle, any **internal combustion engine** can be deployed to generate power. The use of internal combustion engines for power supply is well established, often in standby diesel generators, but gas engines are also used commercially. These stationary engines are optimised to run efficiently at a single load point. These installations are generally up to 30 MW in size and based on a 4-stroke cycle. Marine power units range up to 70-80 MW in size and are 2-stroke engines, offering high efficiency, but their large inertia makes them relatively slow to start up, so the smaller 4-stroke units are assumed to be the more suitable for power generation at this time for all fuel types. The cost of such units would likely fall as a result of increased manufacturing volume, and with a large number of units in a system, efficiency could be maintained across the full range of load by switching units on and off.

Internal combustion engines in power and CHP applications are becomingly increasingly competitive at larger scales with gas turbines, often using arrays of engines to deliver the required power. For example, Wärtsilä have delivered a 600 MW peak power project in Jordan based on 38 multi-fuel engines[73]. The nine-engines in the 76 MW gas burning plant in Kansas cost £30M ($395/kW_e$) 'including appurtenances'[74].

Pure hydrogen engines would be spark-ignition rather than compression ignition unless a pilot fuel were to be included. Hydrogen has a high flame speed and is prone to pre-ignition but these issues are manageable, as are the potential NO_x issues, which are discussed in more detail below. Pure hydrogen spark ignition engines [75] are coming into the marketplace today[76] and are already available from INNIO. and are being developed by JCB[77], Mercedes [78], Toyota[79], Wärtsilä[80] and other companies. Much of the development started by considering modifications of petrol engines, but we have learned that JCB are focussing on the ultra-lean burn conditions that are allowed by hydrogen's flammability, but are not accessible for petrol or diesel engines, with low temperature (which as a side-benefit reduces NOX). It seems that large engines designed to operate in this regime could be (at least) as efficient as PEM cells and cost not much more than petrol and gas engines. Although such engines are only at the prototype stage, it seems possible that large mass-produced hydrogen burning motor-generator sets would fall to or below the $350/kWe inclusive cost of the Kansas plant. If so, 4-stroke hydrogen-burning engines could be cost competitive with fuel cells not only in the short, but in the long term. A graph of the efficiency of electric vehicles published by McKinsey[81] contains 'illustrative' lines which show hydrogen engines being more efficient than diesel engines for all output and more efficient that fuel cells above about 60% of the maximum output.

Ammonia

Ammonia may be used directly as a fuel in internal combustion engines, and possibly fuel cells in the future, or decomposed to generate hydrogen for use as a fuel at the point of use. In some internal combustion engine applications, partial decomposition of the ammonia has the advantage of modifying the flame speed of the fuel into a range more normal for engine designs[82].

Ammonia can be converted back to hydrogen through an endothermic catalytic process, known as cracking (approximately 46 kJ/mol of heat is required, or around 9% of the energy content of the produced hydrogen). The purity requirements of the hydrogen produced by cracking depend on the technology and the downstream separation. This is relatively unimportant for combustion in (e.g.) furnaces, boilers, or turbines, but PEM fuel cells which only work with very pure hydrogen and would have to be fitted with preconditioning for use with impure hydrogen.

Fuel Cells

Ammonia can currently be used directly as a fuel in solid oxide fuel cells, but ammonia SOFCs are still far from developed to enable quick response to large power loads. It has been estimated that the heat required to crack ammonia would reduce the efficiency by some 9%

compared to using hydrogen directly. A Norwegian EU-funded project is installing a 2 MW ammonia SOFC in a ship, and there are plans to then scale up to 20MW[83].

Research is underway into the direct use of ammonia in PEM fuel cells, but this is not likely to be commercialised within the next decade. Alkaline Fuel Cells are not poisoned by ammonia and have higher efficiencies than PEMs (50-60% compared to 40-50% in PEM technology), and are being developed in the UK[84].

A recent study[85] described a device that uses a ceramic membrane to crack ammonia to pure hydrogen at 250°C, raising the possibility of constructing a combined cracker and proton conducting ceramic ammonia fuel cells.

Combustion

Ammonia combustion has been actively researched since the 1930s. Ammonia can be combusted on its own, or in a dual-fuel arrangement which ameliorates the low flame speed of ammonia. Ammonia has a similar energy content per unit mass of stoichiometric fuel-air mixture to gasoline meaning that for a given engine size, power outputs are essentially equivalent, provided that combustion is complete.

The combustion of ammonia may lead to higher levels of fuel-derived NO_x in the exhaust gas, and in higher speed engines un-combusted ammonia will also be present in the exhaust gas. NOx levels and ammonia slip are thought to be manageable through optimisation of the engine design[86,87]. If necessary, selective catalytic reduction (SCR) can be used to achieve NOx concentrations within regulatory limits. The design of mitigation systems in stationary engines operating at constant load is significantly more straightforward than designing such systems for automotive applications.

The first large scale use of **ammonia internal combustion engines** is likely to be to power ships. MAN, Wärtsilä, and other ship engine manufacturers have identified the potential of ammonia as a zero-carbon fuel and are engaged in testing programs for the implementation of two and four stroke engines in the marine sector. MAN Energy Solutions, who provide engines for over half the world's ships, is leading a Danish consortium that aims to deliver commercially viable, zero-carbon, two-stroke engine by 2024[88]**. MAN expects to be marketing two stroke engines with 50% efficiency in 2024,** which can replace units that were initially conceived for LPG fuel. The ability to retrofit ammonia fuelling to the existing fleet is important, because of the relatively slow turnover rate of the world's inventory of ships.

Ammonia is considered to be a suitable fuel for gas engines to generate power in stationary applications, most likely using arrays of 4-stroke engines of 20-30 MW each[89].

The performance and reliability of ammonia gas turbines have been assessed numerically, experimentally, and under industrial conditions[90]. Turbines have been tested with pure ammonia and work on a range of scales from small turbines (~50 kW power, 89-96% combustion efficiency) to industrial systems. Tokyo Gas, the lead participant in a Japan-Australia innovation project, has produced a roadmap to produce the first 100MW ammonia gas turbine by 2030.

Power Generation Options in 2050

Table SI 4.4l ists possible 2050 costs and efficiencies of the generating technologies described in Table SI 4.3 (the lifetimes and opex are not expected to change significantly).

Table SI 4.4: Comparison of end use technologies for hydrogen and ammonia

Power Generation Options in 2050					
	SO Fuel Cells	**PEM Fuel cells**	**4-stroke ICE**	**OC GT**	**CC GT**
Fuel flexibility	H_2*	H_2 only	H_2/ CH_4 / NH_3	H_2/ CH_4 / NH_3	H_2/ CH_4 / NH_3
Capital Cost $/kW	425	425	300	713*	1084*
Fuel to Power Efficiency LHV	65%	55%	52%	34%	58%
*Can also operate with CH4, a H2/CH4 mixture and NH3, but at slightly higher cost and slightly different efficiencies					

From this table, it is apparent that fuel cells and gas internal combustion engines are likely to be the dominant players in this market[iv]. Fuel cells are inherently more efficient and lower maintenance cost than gas engines, but these advantages are offset by the gas engines lower capital cost and lower fuel purity requirements. Over time, fuel cells are likely to close the gap with gas engines on cost.

In the relatively near term, gas engines may be the favoured generation option, but scale up of fuel cell technology would offer greater long-term benefits because of their higher efficiency.

4.6 Safety

A large body of literature exists on the safety of hydrogen and ammonia; they are produced in mature industrial processes at a very large scale. They are also stored a variety of forms and transported over long distances. As a result, there are national and international standards both specific e.g., HSE guidance on stationary applications for hydrogen[91], and generic e.g., COMAH regulation which would apply to many large installations[92]. The nature and behaviour of these materials and associated risks are different from those of more widely used fossil fuels, but they are well-known and documented and appropriate guidance is available.

Hydrogen can be and is handled safely at large scale today with the appropriate equipment and operating procedures. It is non-toxic and, as it is much lighter than air, dissipates rapidly when released. However, it is flammable at a wide range of concentrations in air and has a lower ignition energy than gasoline or natural gas. It can therefore ignite more easily. Moreover, hydrogen (being a smaller molecule) is more likely to leak than natural gas. Adequate ventilation and leak detection are therefore important elements in the design of safe hydrogen systems. Because hydrogen burns with a nearly invisible flame, special flame detectors are required. Furthermore, some metals can become brittle when exposed to hydrogen, so selecting appropriate materials is important in the design of safe hydrogen systems.

Ammonia is caustic and an irritant, with a strong pungent odour, and is also toxic as a vapour and in aqueous environments. Its safe production, storage, transport and use in an industrial

[iv] Modelling in the case that all storage is provided by hydrogen finds (Chapter 4) that the load factor on whatever generates of electricity is 10%. Although the performance of fuel cells deteriorates with age, like that of electrolysers (see footnote XXX), the deterioration will therefore only have a very modest impact on costs over the 30-year financial lifetime assume here.

context is well-established and regulated; these regulations can be used to inform the expanded use of ammonia in an energy storage context. Several studies have indicated that the transport of ammonia presents comparable risk to LPG and gasoline when appropriate control measures are employed[93].

The use of ammonia in fuel applications would specifically seek to avoid environmental release of ammonia, in complete contrast to its use in fertilisers. Finding affordable and completely effective solutions to these challenges, demonstrating technical feasibility and developing the appropriate regulations and safety procedures to enable the inclusion of ammonia as an energy carrier in future energy scenarios will open up more flexible routes towards a low-carbon energy future.

4.7 Climate impact

Hydrogen, which plays an important role in storage in almost all cases considered in this report, is a greenhouse gas (ammonia is not). A recent evaluation[94] found that hydrogen has a 100-year Global Warming Potential (GWP100) of 11 +/-5[v].

In the case of wind and solar supply of 741 TWh/year, an average of 85 TWhe/year has to be provided by storage if there are no other sources of supply. With the assumed conversion efficiency of 55%, an average of 4.7 Mt/year of hydrogen passes into, through and out of the store. very year. A recent analysis by Frazer-Nash[95] finds that purging of hydrogen following electrolysis is the largest potential source of leakage (which could be as high as 10%), but 'it would be relatively easy to incorporate technology to recombine the hydrogen purged and vented due to cross-over back into water. As electrolytic hydrogen production is scaled up, it will become more feasible to incorporate this technology'. Assuming (following Frazer-Nash) that this is done, and that production and generation are not co-located, the analysis suggests the following leakage levels, with 50%/99% confidence

Electrolyser 0.24%/0.52% + transport to store 0.04%/0.48% + compression 0.25%/0.89% + storage 0.02%/0.06% + transport from store 0.04%/0.48% + fuel cell 0.56%/1.02% = 1.15%/3.45%

leading to release of 54/162 kt/year. Starting up steady emission of these amounts would lead to a temperature rises of 22/66 x 10^{-6} ^{0}C after 20 years, and 42 [127] x 10^{-6} ^{0}C in the long-term (> 300 years) future (using the central value of GWP100, an analysis of the impact of short-lived greenhouse gases[96], and ignoring uncertainties in the climate science). These numbers are only for hydrogen used to store electricity in GB, but they suggest that, unless the world starts to produce hydrogen at a very much larger scale than currently envisaged (IRENA foresees a need for 154 Mt of hydrogen in 2030, although it seems that this includes little if any for electricity storage[97]; National pledges reported by the IEA include production of 288 Mt of hydrogen in 2050[98]), the climate impact will be small, although it will be important to take care when shipping hydrogen (IRENA foresees 25% of hydrogen production being traded internationally in 2050[99]), and to take measures to limit emissions to the levels found by Frazer Nash (even with 10% emissions in electrolysis the limit of 127 x 10^{-6} ^{0}C would only increase to 475 x 10^{-6} ^{0}C, although allowing for uncertainties in GW100 and the climate science could double this number).

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[v] Compared to the more familiar case of methane (another short-lived greenhouse gas), the temperature impact of hydrogen is 0.39 that of methane (GWP100 27-30) per tonne emitted, but only 0.16 that of methane per unit of energy emitted.

Annex SI4 Concluding Remarks

Hydrogen and ammonia are technically viable options for storing power, although the round-trip efficiencies are low. The cost of the electricity provided by hydrogen and ammonia stores is high, but as stressed in Chapter 1 and quantified in Chapter 8, the averge cost of electricity, which is dominated by the cost of wind and solar supply, is nothing like as high as might have been expected. Hydrogen production is already fully commercialised for some electrolyser types, while hydrogen end-use technologies are still developing. Similarly, electrochemically-driven ammonia production has been practiced extensively in Norway, but ammonia end-use technologies lag those using hydrogen.

Provided hydrogen can be stored underground, ammonia will not be able to compete with hydrogen for storing power at the necessary scale in the UK[vi], unless or until much cheaper ways of making ammonia are developed, by a process that can load follow (although ammonia imported from places where very low-cost solar power is available could play a role as a source of power, as well as playing other roles).

The costs found in Chapter 4 and SI 4 that are used in modelling storage are summarised in Table 8.2

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SI 5 Non-chemical and Thermal Energy Storage

5.1 Introduction

Remarks on Costs

Most of the storage systems discussed in Chapter 5 have large capital costs, which can only be recovered if they are cycled relatively frequently, making them unsuitable for storage over very long periods. However, as well as medium-term storage, many can also provide short-term services which would improve their economic viability.

Systems that can recoup the investment costs with cycles of a few days could be supplemented by additional longer-term storage units (1-3 months). In a future renewables dominated supply system these additional storage units would be most cost effective if they could be charged using low-cost electricity available at times of excess generation, and discharged at times of low renewable generation when load is greater than supply leading to higher prices (when the medium-term storage unit is already discharged) using the existing generation equipment, so that only the cost of the longer-term storage units would have to be recouped: this possibility deserves further investigation.

Without supplementary storage units, storage duration of more than a month with TWh storage capacity could only be provided by heat stores charged in summer and used to provide heat through district heat networks in the winter, or possibly large very well insulated heat stores used to generate electricity or thermochemical storage. Even with supplementary units, losses limit the storage time, except in the case of thermochemical storage. Thermal losses depend on store size, insulation levels and temperature: for low temperature ACAES heat stores they might be 10-20% in six months, and 8% in 100 days from the cryogenic store in LAES, although losses in very large very well insulated underground heat stores could be much smaller (Cabeza[1] quotes 78% to 90% annual efficiency for large-scale pit storage of water)

5.2 Advanced Compressed Air Energy Storage

Existing Systems

The Huntorf, Germany and MacIntosh, USA CAES plants, which use gas combustion to heat the air on expansion, have round trip efficiencies (defined as energy out/total energy in) of 42% and 54% respectively. These two plants, should be regarded as compressed air assisted combustion systems rather than energy stores, have a combined experience of nearly 75 years of operation.

Isobaric ACAES, in which hydrostatic compensation is used to maintain the stored air at constant pressure during operation, is being developed by a company called Hydrostor Inc [2]. A demonstrator that can store over 10 MWh came into operation in late 2019 in Ontario, and three plants that can store a few GWh are planned/under development (in Canada, Australia and California). An efficiency of 60% is claimed for the small 10 MWh Hydro demonstration system in Ontario [3].

Underground Storage Capacity in GB

Storage in porous rock formations appears to be the cheapest option (Box SI 5.1), but onshore salt caverns (the second cheapest) will be assumed in costings in this report – a choice endorsed by the British Geological Survey whose conclusions are quoted in the Report.

Box SI 5.1 Underground storage in caverns and aquifers

Location: Infrastructure and suitable geology are important considerations for siting CAES systems. Salt caverns are better than porous rock, easier to create and better than hard engineering approaches that might weaken rock. Geological questions still to explore include; what are the operational limits and stability? How does cavern shape effect performance? How long are salt caverns operable for? Potential sites in the UK have been explored by the British Geological Survey. However, use of these sites for ACAES will be in competition with, and may interact with, other potential uses, for example hydrogen and natural gas storage (although, as discussed in Chapter 4, the potential for storing hydrogen in salt caverns is very much greater than will ever be needed). Pore space storage in aquifers/porous rocks can be used for thermal energy storage and potentially for natural gas, hydrogen, compressed air and CO_2 (from CCS) storage.

Evans et al[4] (see also Parkes et al [5]) found a potential for storing several tens of TWh in solution-mined salt caverns, after eliminating locations close to surface infrastructure and other features that might impede cavern development (John Williams of the British Geological Survey provided very helpful information that forms the basis for the parts of this and the following paragraphs that go beyond refs. 4 and 5, of which he is one of the authors). However, this includes contributions from caverns off the Wessex coast and in the East Irish Sea, which would be relatively expensive to develop and hard to equip with the thermal stores required in ACAES. Evans et al argue that cavern heights should be limited to 100–150 m as 'smaller[caverns] are less economic to operate for gas storage … and … very large (tall) caverns carry stability issues and operational limits for rapid cycle storage'. With this constraint and allowing for the fact that only about a third of potential in Wessex is onshore, the theoretical potentials that they reported are shown in Table SI 5.1.

Table SI 5.1 Onshore ACAES Storage potential[4]. As explained in the text, these numbers are upper bounds for storage down to a depth of 1,500 m, but there is additional potential at greater depth in Wessex and particularly in East Yorkshire.

ACAES Storage Potential TWh[i]		
Depth	500 - 1300 m	500 - 1500 m
Cheshire	2.80	4.1
Wessex	6.1	15.2
E England	0.69	3.9

It is important to note that i) Wessex (where the potential is poorly characterised compared to other areas) is said (with the East Irish sea) to 'represent higher-risk target storage horizons', and ii) Evans et al suggest further filtering, reflecting an expectation that many of the modelled caverns will not be built due to site-specific constraints (obtaining planning permission will be one constraint; in an extreme case, Evans et al suggested excluding 99% of the initial totals). The potential capacities in Table SI 5.1 therefore represent upper bounds for the given depth ranges.

[i] These estimates are of the static capacity for 'convective heat transfer exergy' defined in ref 4, which - given that withdrawal and filling rates considered in this report are less than 2%/hour - is the same as the energy stored in the thermal plus compressed air stores to well within the uncertainties.

For depths below 1000 m, the maximum air pressure that salt caverns can sustain, which increases with depth, is below the 200 bar considered here. The salt deposits that extend beyond 1,500 m depth in Eastern England and Wessex were excluded by Evans et al., who quote a study[6] that argued for a depth limit on the grounds that the minimum pressure that a cavern can sustain also increases with depth[ii], reaching 100 bar at around 1,500 m, and compressor power is limited to 100 bar. Much higher pressure can, however, be reached with compression in many stages, as assumed here. The existence of an increasing minimum pressure restricts the allowed pressure range unless the maximum is also allowed to increase to more than 200 bar (this restriction could be avoided by using isobaric ACAES, although this would be challenging with deep caverns).

As discussed in section 5.1.2, the BGS's estimates of GB's potential hydrogen storage capacity are used for ACAES in this Report.

Modelling ACAES

The A in ACAES is sometimes taken to stand for Adiabatic (rather than Advanced). However, the more of the heat generated by compression is removed from the air at close to ambient temperatures, the closer compression is to isothermal rather than adiabatic, and the more energy can be stored. In the limiting isothermal case, in which the overall efficiency is highest, the energy is actually stored in the thermal store, while the compressed air stores exergy - the ability to do work (although to approach an isothermal system thermal stores would have to be very big and there is a trade-off between size and efficiency).

Depending on the number of compression and expansion stages, the heat of compression can be stored and used at different temperatures. With two stages, for example, the heat extracted by heat exchangers would have a temperature of some 350 °C and would most likely be stored in molten salts. Modelling with multi-stages stages is described below: with lower compression ratios, the temperature of the heat generated by compression reduces and can be selected to allow air-water heat exchangers to be used to cool the compressed air between each stage to ambient temperature, with water used for thermal storage. Exergy losses and irreversibilities in all components of the system (compression, expansion, throttling, and heat exchangers) and heat loss reduce the system efficiency. A detailed analysis assessing losses and why performance of demonstration systems to date falls below theoretical values is presented in a recent paper[7], which clearly highlights the need for bespoke compressor and expander designs optimised for ACAES applications

Storage of compressed air in 300,000 m^3 caverns with the top of the caverns in the depth range from 1000 m to 1,700 m was modelled.

At 1000 m a pressure range of 48 to 184 bar was assumed, which is close to the full range that is possible. In order to limit the temperature to a level that allows water pit storage of the heat to be used, which is relatively cheap, it is assumed that compression and expansion are carried out in six stages. Following the first stage, the model allows a water temperature that varies in the range to 35-90°C, while the air is heated to 70°C prior to expansion, and cools to

[ii] CAES caverns are liable to experience far greater pressure drop rates than conventional gas storage caverns, and careful consideration must be given to the increased thermal and mechanical loading/unloading for ACAES caverns operating at high pressures in order to ensure cavern integrity. However, in the conditions considered in this report, the modelling described in Chapter 8 found relatively modest pressure drops of less than 2%/hour, averaged over all caverns, and it is assumed here that the temperature rise of the compressed air entering the cavern is limited.

5°C after expansion. In compressing and expanding the air, the isentropic efficiency is assumed to be 0.9, which means that more work input is required to achieve a given cavern pressure and less work output is achieved on expansion. To provide constant pressure input to the expansion process, it is assumed that the compressed air is passed through a throttle to reduce the pressure to the minimum cavern pressure. This leads to a reduction in the round-trip efficiency: to limit this reduction, three stages of throttling between the maximum and minimum cavern pressure were assumed. With these assumptions, for each cavern: the work input for compression is 7.0 GWh, and aided by 5.2 GWh of thermal storage, the store can deliver 4.8 GWhe. 6.75 GWh of thermal energy are in fact generated by compression: the possible use of the excess is discussed below.

The corresponding key figures **at 1,700 m** are: 80 to 322 bar, 7 stages of compression and expansion, and per cavern: energy of compression 13.6 GWh, thermal energy generated 13.2 GWh of which 10.2 are needed to support an electrical output of 9.3 GWh

The difference will be split **for modelling and costing purposes,** and 6 stages of compression and expansion will be assumed with: 10 GWh work of compression, 6.8 GWhe output, supported by 7.5 GWh thermal storage, and total thermal energy generated in compression 9.7 GWhth. Note that

i) Efficiencies significantly higher than the 68% found here, on the basis of not fully optimised modelling, which however does not take account of other needs for power, e.g. for pumping, are possible in principle. However, until a large working system is built, it would be prudent to ere on the conservative side.
ii) The excess 9.7 -7.5 = 2.2 GWh thermal energy that is not needed to support expansion, could be used for other purposes, e.g. to provide input to a district heat network. This could provide revenue which could be offset against the cost of using ACAES to store electricity.

Thermal Storage at high temperatures could be provided by molten salt or water, in which case a heat exchanger would be needed, or by a rock packed bed either contained in a pressurised vessel through which the compressed air would be passed (this would be prohibitively expensive in large-scale systems), or equipped with air to air heat exchangers to avoid the need for pressure vessels. On the scale considered here, simple water pit storage at below 100^{0}C, at a cost of around \$10M/5GWh[8], would appear to be the cheapest and best option, assuming that ACAES will not be called on to provide storage for months.

Charging and discharging.

Efficiency: The modelling described above found a round-trip efficiency of 68%. Most current predictions range from 52-70% (electricity-to-electricity) efficiency, but higher values are theoretically possible[9] and a PNNL report[10] gives > 70%. IRENA's 2030 Reference Case is 68%: their Best Case of 85% is an outlier. To obtain high efficiencies, turbomachinery designed and optimised for ACAES applications is required. With very good thermal storage and optimised turbo machinery 80% or higher is possible in principle.

Switching from full-rated-power-charging into full-rated-power-discharging is dependent on expander/turbine operational temperatures, with usual material-based restrictions applying with higher expander operational temperatures requiring longer times[11], but 5 minutes is a reasonable expectation should rapid switching be required.

Costs of compressors and expanders

According to the literature[11 12 13 14 15 16] the capital costs per kW of power conversion, compression and expansion are expected to be in the range \$150-500 per kW_e for both input and output. However, it is not always clear what is included in these estimates. Reports produced by PNNL[12] and particularly Sandia[1616] imply that \$300/kW_e (including the balance of plant) might be a reasonable value to assume for 2050, assuming large-scale roll out. However, the cost of compressors and expanders grows approximately as $(\text{power})^{0.6}$ and depends on how many stages of compression/expansion are involved. According to a vendor (Tony Kitchener, KDR Compressors Pty Ltd, private communication, April 2021), 50 MW_e multistage compressors and expanders (the sort of size needed for a 5 GWh ACAES system), provided in containerised units that include most of the necessary hardware, plumbing, and wiring, could well cost less than \$100/kW_e in 2050 if manufactured at scale, e.g. production of a few units a week: this opinion was supported by actual 2021 quotes for three 900 kW_e compressors at \$183/kW_e each, and less than \$150/kW_e for a 30 MW_e expander, including base, generator, controls etc. On the basis of this information, it would appear that the full 2050 cost (including site purchase and preparation, engineering design, installation, and ancillary equipment and other owner's costs) could be well within the range of up to £500/kW_e studied in the report.

It is possible to build reversible compressor/turbine units (which have been the subject of a number of patent applications, e.g. by General Electric in the USA[17]). They would suffer a performance penalty (of perhaps a few percent) but this would probably be more than offset by lower capital costs.

5.3 Thermal and pumped thermal energy storage.

Sensible and Latent Heat Storage

Many applications for phase change materials have been proposed, including space heating, space cooling, greenhouse heating, waste heat recovery systems, clothing, ice slurries, building products. Some have reached commercialisation, but latent heat storage currently plays only a limited role in the UK, e.g. in heating and cooling buildings (see e.g. ref[18]) and is not expected to play a role in large-scale erectly storage.

Table SI 5.2 lists a variety of sensible- and latent-heat storage media, from which a selection can be made according to: (i) the form of the energy at charge and discharge (electricity and/or heat), (ii) the scale of the application, and (iii) the storage duration (short or long-term). Recently work on cryogenic temperature latent heat storage was reported[19] for application with a liquid air system.

Table SI 5.2 Commonly used materials for thermal storage, for low-grade (-20 to 100 °C) and high-grade heat (cooled below -20 °C or heated above 100 °C).

	Sensible heat storage		Latent heat storage	
	Low grade	**High grade**	**Low grade**	**High grade**
Heating	Water	Molten salts	Organic compounds	Encapsulated salts
	Solid materials	Solid materials	Salt hydrates	Salts
		Thermal oils	Eutectic mixtures	Metals and alloys
		Liquid metals		
		Steam		

Cooling	Water	Solid materials Low Temperature Phase Change Materials	Ice	Cryogenic gases
	Water – glycol		Organic compounds	

Storage capacity: Individual thermal stores can be very large, depending on their application. Concentrating solar thermal power stores of over 375 MWh_e capacity (volume 14,000 m^3)[20] have been in use for several years. Much larger systems are becoming operational, for example the 1.2 GWh_e store associated with the now defunct Crescent Dunes CSP plant, while district heat stores of 1.8 million m^3 are being proposed in Europe[21] with a storage capacity of over 100 GWh of heat. Thermal storage systems are both distributable, based on available space, and scalable, with no real limits to how many of these systems could be operated in parallel.

Efficiency: 'Heat-to-heat' storage systems for utilisation in district heating systems are, depending on scale, able to achieve efficiencies of over 90% for storage durations of 120 days (from late summer to winter), and can be charged using a range of heat sources including solar thermal, heat pumps - which could be powered by otherwise surplus wind and solar energy, and biomass combustion.

Electricity → heat → storage → heat → electricity systems can (using resistance heating), depending on duration, achieve efficiencies of 40-45% electricity-to-electricity or higher for some forms of Carnot batteries (Box SI 5.2). Where high temperature heat is the initial product, for example in a nuclear power station, the loss from going through storage, rather than directly converting the heat to electricity, could be much less than 10%.

Box SI 5.2. Thermal energy storage, - potential scale, current demonstrators

Increasing the temperature range over which a store is charged-discharged increases the energy storage density. Materials used to date for storage linked to concentrating solar thermal power systems include molten salts, rocks, and molten salts within a rock packed bed. To store sufficient heat to produce 1 TWh_e using molten salts with a 200 K operating temperature range, 20 million m^3 would be required (at higher temperatures, a gas blanket at the top of each of the storage systems could be required to accommodate thermal expansion); when discharged, a heat exchanger would generate steam which would power a conventional steam turbine. At such a large scale, rocks (in which voids take up much of the thermal expansion) would be cheaper than molten salts. 20 million m^3 is the size of some eight large Amazon warehouses, or stores 20m high covering an aggregated area equivalent to 140 football pitches.

On a much smaller scales, a thermal energy storage system developed by the company EnergyNest[22] utilises concrete modules with embedded stainless-steel heat transfer pipes to provide a scalable energy storage solution to multi GWh capacity. The materials costs are down to \$25/kWh_{th} depending on system scale/location and operating temperatures that can be obtained. Siemens Gamesa are currently demonstrating a 30MW high-temperature (> 600°C) thermal store utilizing 1000 tonnes of volcanic rocks to store 130MWh[23,24] with claimed electrical-electrical round-trip efficiency of 45%. Commercial scale is aimed at greater than 5GWh storage with 100MW output.

Systems such as these that buffer electricity to electricity by storing heat provided by a resistive heater or a heat pump system, for later delivery as electrical power, are known as Carnot Batteries. They are of increasing interest for large scale storage with a range of different configurations, storage, charge/discharge cycle being considered. The efficiencies for different power cycle options are analysed and presented by Steinmann et al[25].The predicted round-trip efficiencies for a Compressed Heat Energy Storage system (CHEST), which combines sensible and latent heat storage with a subcritical Rankine process, are over 60% for turbine and compressor isentropic efficiencies of 0.8 and above. A recent review of Carnot Batteries includes indicative prices for a range of system options including liquid air energy storage[26]. **A recent assessment of the cost of Carnot batteries is provided in the following subsection.**

In a recent paper, Davenne and Peters[27] assessed two designs for a 1 GWhe pumped thermal energy storage system, one in which the stores were directly charged by the working fluid resulting in the hot store requiring a pressure vessel and one in which heat exchangers were used to decouple the stores from the working fluid, allowing near ambient pressure storage to be achieved. The systems simulated required a total of 90,000 m^3 of storage (60,000 m^3 cold and 30,000 m^3 hot) filled with gravel with a packing density of 0.5. Although the decoupled system achieved lower predicted round-trip efficiencies (59.5%) the large cost reduction compared to the coupled system leads to a more cost competitive storage solution.

Time frame

The appropriate time period for storing thermal energy is dictated by heat leakage and economics. It is often possible to reduce heat leakage to much less than 1% of the stored energy per day with acceptable levels of insulation, particularly for large systems, which benefit from a low ratio of surface area to volume. For large low-grade storage, losses can be exceptionally low, for example heat losses in water or phase-change-materials can be 0-0.5% of the stored energy per day (0.1% heat loss corresponds to a <10% cumulative loss over 3 months). Large-scale underground thermal storage systems can take several years to reach steady state operational conditions with lower charge/discharge efficiency achieved over initial years.

Charging/discharging

Charging and discharging rates strongly depend on storage system design, storage material used and heat transfer. For heat-to-heat systems roundtrip efficiencies can be very high (above 90% for large scale stores).

Potential and development

The estimated properties and performance of different thermal storage applications can be found in Table SI 5.3. Further research is needed to improve i) long-term large-scale heat storage system designs and materials, both at low and high temperatures, ii) determine scenarios and scales of storage to generation for optimum cost effective operation, iii) develop/improve thermochemical storage materials and systems working at both low and high temperatures, and iv) determine if integration with nuclear generators is cost effective for long term electricity storage and can allow nuclear electricity generation to be fully flexible. Demonstrations at scale are required.

Table SI 5.1 Examples of thermal storage applications and their performance.

Application	District heating pit storage	Thermal Storage Coupled to Nuclear Power Plant Concentrating solar power (CSP) plant	Pumped thermal energy storage (Joule-Brayton cycle)
Thermal storage medium	Water	Molten salt	Thermocline gravel packed beds
Charge/discharge	Heat in/heat out	Heat in/electricity out	Electricity in/electricity out
Temperature range	50 to 95 °C	300 to <580 °C	-150 to 500 °C
Long-term operation	Yes	No	No
Self-discharge rate	< 0.1%/day	<0.1%/day	~0.5%/day
Typical unit scale	2,000 - 10,000 MWh$_{th}$	100 - 1,000 MWh$_e$	1 - 50 MWh$_e$
Lifetime	30 years	30 years	25 years
Geographic constraints	Typically underground where possible	Strong direct solar resource for CSP	Flexible
Cost	0.5 - 12 £/kWh$_{th}$[28]	24-59 £/kWh$_{th}$[29]	150 - 200 £/kWh$_e$[30] 850 - 1,050 £/kW$_e$
Energy Density	81.6 kWh$_T$/m^3 (ΔT=70°C)	53.57kWh$_e$/m^3 (ΔT=200°C)	11.1 KWh$_e$/m^3 (T1= 500°C, T2 = - 150 °C; 50% packing[27])
Technology readiness level	9 (commercial)	9 (commercial)	-4/6 (demo)

Carnot batteries[iii]

The potential for large-scale thermal storage to play a role in a future electricity supply system with a combination of renewable and nuclear generators is an area of growing interest. For use with nuclear generators in which heat from the reactor is stored directly and subsequently converted to electricity when demands are high, conversion efficiencies can approach those obtained when heat from the reactor is used directly. When using electricity generated by renewables that is excess to demand to charge a thermal store, the conversion of electricity to heat by simple resistance heaters is highly efficient. For the conversion back to electricity the efficiency that can be obtained is strongly dependent on the temperature with higher storage temperatures leading to higher efficiencies. Efficiencies of conversion of heat back to electricity are temperature dependent with efficiencies of 45% or higher being possible using

[iii] This section, which was written by Professor Philip Eames, Loughborough University, describes the first steps in an on-going detailed analysis of storage system design, operation, heat loss and costs.

steam Rankine cycles with steam temperatures of 600°C. The use of higher temperatures allows other cycles to be employed with efficiencies increasing to above 50%.

For large-scale long-erm thermal storage abundantly available low-cost materials are essential to achieve low cost per kWh of storage capacity. Potential materials include graded quarried igneous rock aggregates that are stable at temperatures of intended store operation, for example 600°C, and are readily available at low cost.

Store geometrical considerations.

In heat storage systems heat storage capacity is proportional to store volume, heat losses are proportional to store surface area, store geometries should therefore seek to maximise store volume while minimising surface area.

Packed bed thermal energy storage systems consist of a matrix of storage materials, pebbles, through which a heat transfer fluid flows to deliver/extract heat from the store. Depending on the temperature, heat transfer fluids can be liquids or gases. During charging/discharging of the packed bed a thermocline or temperature gradient zone will develop, if not fully charged or discharged in a cycle the temperature gradient zone will expand over time between cycles reducing the quantity of material at the design storage temperature. When fully charged, prior to discharging local temperature gradients will develop in the store material adjacent to the boundaries where thermal losses occur, the bulk of the store material will however be at near uniform temperature.

The heat storage capacity (HSC) of a sensible thermal energy store is a function of the volume (V) of the store, the density of the storage material (ρ), its specific heat capacity (C_p), packing factor$(P_{f)}$ and temperature range of operation$(T_{max} - T_{min})$. For a cylindrical store V=$\pi r^2 h$ where r is the store radius and h the store height. The HSC for a cylindrical store is given by equation 1.

$$HSC = \pi r^2 h \rho C_p P_f (T_{max} - T_{mi}\ ) \qquad (1)$$

The heat loss (HL) from a store is a function of the store surface area (SA), store heat loss coefficient (U_L) and temperature difference between the store and the ambient temperature. For a cylindrical store the HL is given by equation 2.

$$HL = 2\pi(r^2 + rh)U_L(T_{max} - T_{amb}) \qquad (2)$$

The ratio of HSC to HL if the store height is equal to the store radius and T_{min} =T_{amb} is given in equation (3).

$$HSC{:}HL = \ r\rho C_p P_f{:} \quad 4U_L \qquad (3)$$

This indicates that for larger stores the ratio of heat storage capacity to heat loss increases linearly with the store radius. The ratio also indicates the importance of high material density, specific heat capacity and packing factor in increasing energy storage capacity for a given store volume compared to heat losses.

The store costs are comprised of three main elements, i) the packed bed energy storage material cost (ESMC), ii) the store containment and insulation cost (CIC), and iii) excavation costs (EC). The excavation costs and energy storage material costs are a function of the store volume, the store containment and insulation costs are a function of the store surface area. For a cylindrical store with the height equal to the store radius the total store costs (TSC) are given by equation (4) which can be simplified to equation (5).

$$TSC = \pi r^3 (ESMC + EC) + \ 4\pi(r^2)CIC \qquad (4)$$

$$TSC = \pi r^2 (r(ESMC + EC) + \ 4CIC) \qquad (5)$$

To allow for thermal expansion of the packed bed material an actual store design would be based around a truncated inverted cone rather than a cylinder.

Illustrative thermal storage capacities and costs

To calculate the maximum and minimum likely costs for a packed bed thermal storage system a simple analysis was performed for cylindrical stores, with store height equal to store radius for stores with a radius up to 60 m. The key parameters for the store are included in table 1 and the high and low costs used in the scenarios are included in table 2. The excavation cost of zero for the low-cost scenario assumes that an existing hole, for example a quarry can be repurposed at negligible cost. The store heat loss coefficient is based on a 0.5m thickness of mineral wool with a thermal conductivity of 0.5W/m/K at 600°C. The heat loss coefficient would be less than this in reality due to other parts of the containment structure contributing to the thermal resistance, the mineral wool having lower thermal conductivity at lower temperatures, temperature gradients within the packed bed adjacent to the store wall and temperature gradients in the surrounding earth. A detailed design for containment is required to evaluate costs and heat losses more accurately.

Table 2 *Aggregate properties, store operating temperatures and store dimensions*

Parameter	
Aggregate density	3000 kg/m^3
Aggregate specific heat capacity	800 J/kg/K
Aggregate packing factor	0.75
Store heat loss coefficient	1 W/m^2/K
T_{max}	600 °C
T_{min},T_{amb}	20 °C
Radius,height	1-60 m

Table 3 Employed low and high costs for prediction of store costs

Parameter	Low-cost scenario	High-cost scenario
Aggregate cost	10$/tonne	70$/tonne
Excavation cost	0	102$/m^3
Store containment and insulation cost	2000$/m^2	4000$/m^2

Figure 1 presents the increase in store surface area and store volume for increasing store radius from 1 to 60 m with store height equal to the radius. It is clear that the volume and thus energy storage capacity increases at a much greater rate than the surface area and thus heat losses with increasing radius.

Figure 2 shows the heat stored within a fully charged store in GWh for a store operating temperature range from 20 to 600°C and the maximum rate of heat loss in kWh/s for a store heat loss coefficient of 1 W/m^2/K when the store is fully charged. The 60 m radius 60 m high store stores 196GWh of heat with a maximum heat loss of 7.3 kWh/s. The 30m radius 30m high store stores 24.6GWh with a maximum heat loss of 1.82 kWh/s. With this high heat loss coefficient, for the 60 m radius store 0.32% of the stored heat is lost in 24 hours and for the 30m radius store 0.64% of the stored heat is lost in 24 hours.

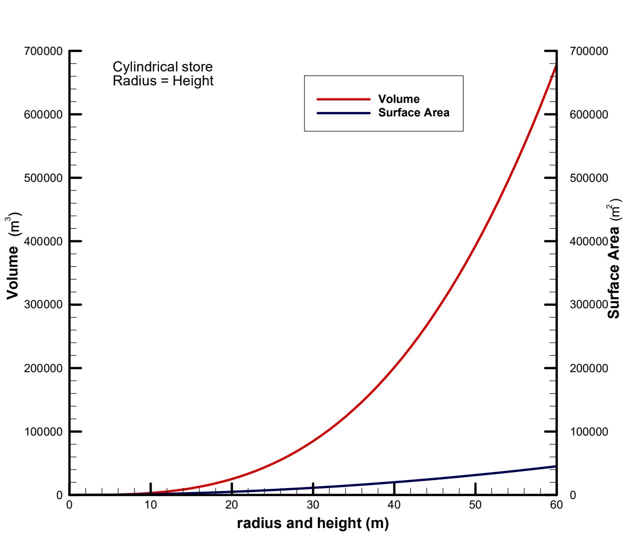

Figure 22 *Store volume and surface area with store radius for a cylindrical store with store height = store radius*

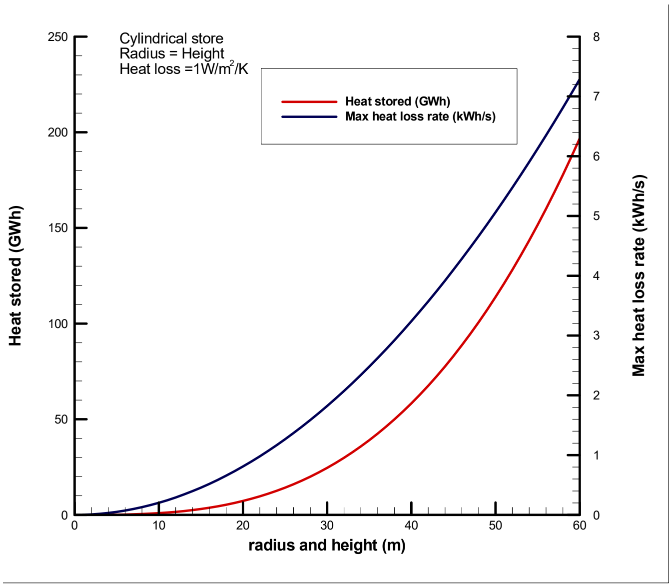

Figure 23 *Heat stored and the maximum heat loss rate with store radius for a cylindrical store charged to 600 °C from 20 °C with store height = store radius*

From figure 3 it can be seen that if very low-cost aggregate materials can be used for the store packed bed the majority of costs associated with the store are due to the store enclosing structure and insulation.

From figure 4 it can be seen that the costs associated with the store enclosing structure and insulation are the largest contribution to the storage system costs. At 60m radius the combined costs of excavation and materials is $176M while the enclosing structure costs $181M.

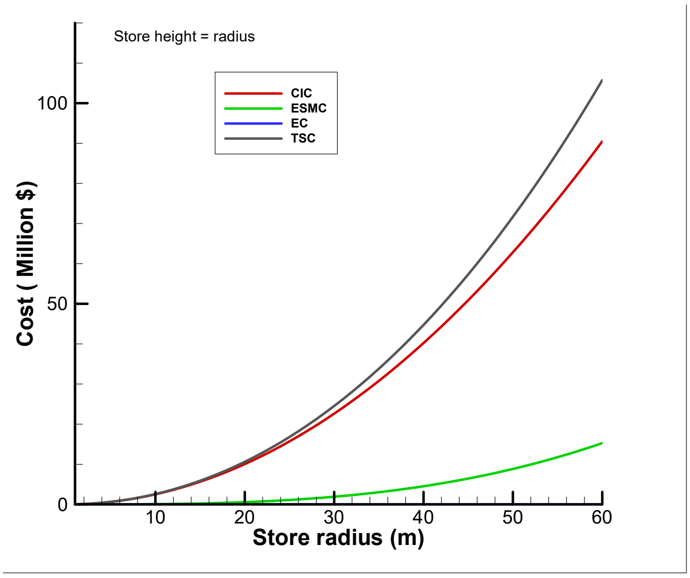

Figure 24 *Contributions to store costs and total store costs with increasing store radius for the low-cost scenario. CIC = the store containment and insulation cost, ESMC = the packed bed energy storage material cost, and EC= the excavation cost, and TSC = the Total Storage Cost.*

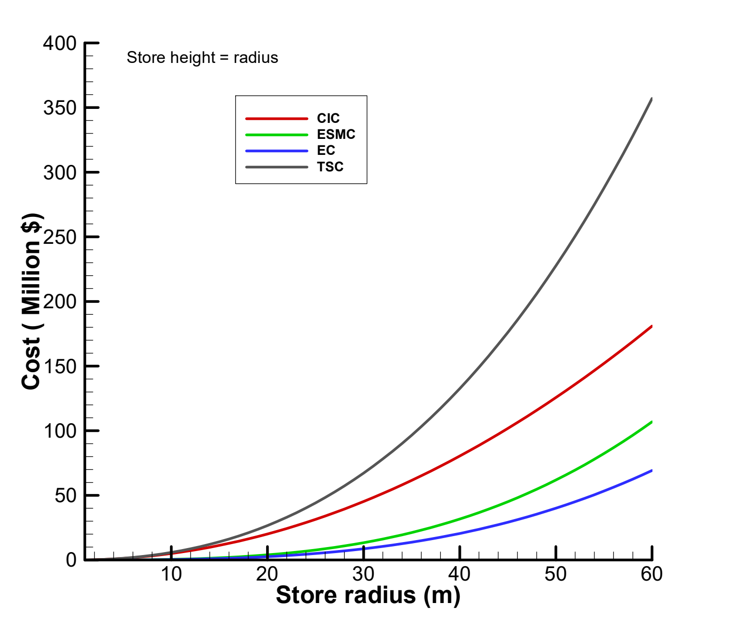

Figure 25 *Contributions to store costs and total store costs with increasing store radius for the high-cost scenario. CIC = the store containment and insulation cost, ESMC = the packed bed energy storage material cost, and EC= the excavation cost, and TSC = the Total Storage Cost.*

A key consideration for long-term large-scale energy storage is the cost that can be realised per kWh of storage capacity. Figure 5 and 6 present the costs per kWh of storage capacity for the two cost scenarios. It is clear that small stores have high costs per kWh of storage due to the low store volume and storage capacity. With increasing store radius, the costs rapidly reduce, for a 5m store radius the storage capacity is 113 MWh and the high and low scenario costs are 11.93 and 5.59 $/kWh. For a store radius of 10 m with a storage capacity of 911MWh there is a reduction in costs to 7.03 and 3.14 $/kWh for the high and low-cost scenarios.

From figure 6 it can be seen that for stores with radius greater than 10m the cost kWh of storage capacity continues to decrease with increasing radius but with the rate of decrease reducing. For 20m, 30m and 60m stores the storage capacities are 7.28GWh, 24.59 GWh and 196.79 GWh with for the high cost scenario costs per kWh of storage capacity of 3.65, 2.73, and 1.81, and for the low-cost scenario costs per kWh of storage of 1.46, 1.00 and 0.54 $.

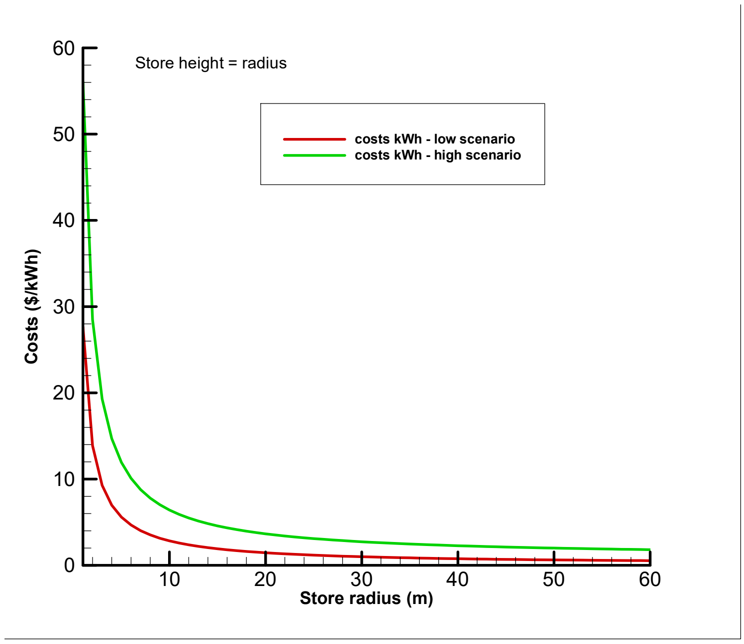

Figure 26 Costs per kWh of storage capacity with store radius 1m-60m

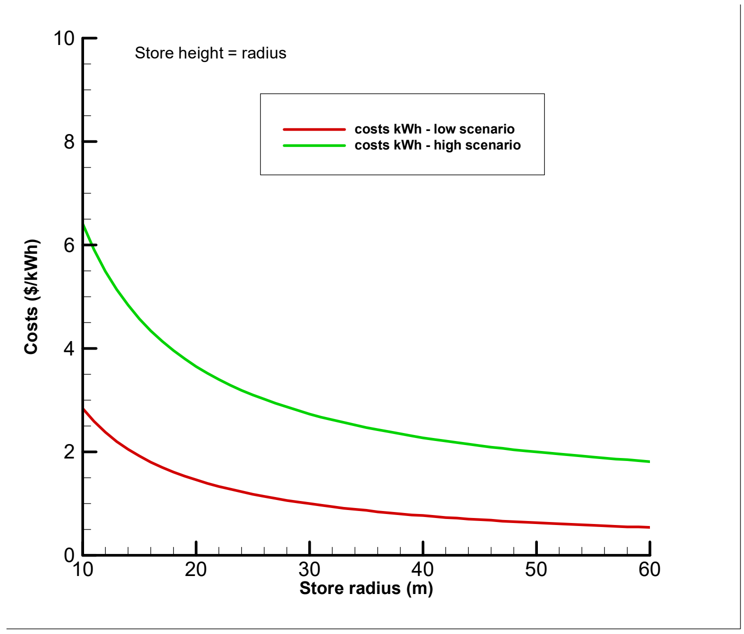

***Figure 27** Costs per kWh of storage capacity with store radius, 10m - 60m*

Assuming that a conversion efficiency of 0.45 from heat to electricity can be achieved the equivalent storage capacities in terms of electricity for the 20m, 30m and 60m stores are 3.28, 11.07 and 88.55GWh with costs per kWh_e capacity of 8.11, 6.06 and 4.02 $ for the high-cost scenario and 3.24, 2.22 and 1.2 $ for the low-cost scenario.

Conclusions

Thermal stores that use readily available abundant low-cost materials have the potential to deliver low cost per kWh storage capacities. Even when assuming a high heat loss coefficient from the stores of $1W/m^2/K$ heat loss rates from a 30m radius store 30m high are 0.64% of stored energy in 24 hours, in reality the loss is anticipated to be significantly lower. A more detailed analysis of storage system design, operation, heat losses and costs, which is required, is being made by Professor Philip Eames Loughborough University), with particular emphasis on refining the costs of the store containment and insulation.

Pending a full analysis, note that according to the figures above a 60m high-temperature store would store 190 GWh_{th} and cost between £1.0 and £3.3/kWh_{th} (with $/£ exchange rate in September 2023), compared to the low/central/high estimates of hydrogen storage costs of £(0.27/0.40/0.53)/kWh_{LHV} found in Chapter 4. If the power to heat efficiency is 0.9 then assuming reconversion with 45% effiency (Rankine cycle), the round- trip efficiency would be 40.5% (compared to 40.7% assumed for hydrogen in the Report). This is closely in line with the conclusions in Section 5.2. However, if some of the heat were used for heating purposes, even if only for part of the year, this could increase the input efficiency to 95% (and there are some suggestions in the literature that output efficiency could be much higher than 45%). The cost of converting electricity to heat will be much lower than for converting it to hydrogen, while the costs of re-conversion would be similar using a turbine but higher if the Report is correct in finding that CCGTs are not the cheapest option for hydrogen. Given their very high energy storage density, very-large high-temperature Carnot batteries could therefore play a significant role complementing the large-scale long-duration hydrogen storage that will be needed, if these conclusions survive further analysis.

5.4 Thermochemical Heat Storage

In thermochemical heat storage, heat energy is converted into chemical potential energy through a reversible reaction. This process is presently at the lab-scale but is expected to provide long-term energy storage with lower energy losses than 'sensible' or latent-heat storage and higher energy storage densities when deployed (the anticipated time required for development and demonstration at scale is around 8-10 years). A review of thermochemical heat storage is presented by Aydin et al[31].

A wide range of potential reactions have been identified in the literature and include gas-gas, liquid-gas, solid-gas, and chemical sorption reactions. If the reactants Y, Z can be stored separately, long periods of energy storage can be achieved with low levels of energy loss - essentially only sensible heat is lost when the reactants cool to ambient temperatures. It is of critical importance that the selected reaction has the correct turning temperature at which the dominant direction of the reaction changes, is reversible (and no secondary reactions prevent reversibility), and that the reaction rates can be controlled so that charge and discharge rates are appropriate for the intended application. Catalysts and operational pressures can be used to modify reaction turning temperatures and reaction rates.

Example reactions with theoretical material energy densities and reaction temperatures[32,33] are described in the Report. An example of distributed inter-seasonal thermochemical heat storage that is being researched uses solar thermal systems to provide heat for dehydration of $MgSO_4 \cdot 7\,H_2O$ in summer, moist air being used in winter to rehydrate the $MgSO_4$ and deliver heat for space heating[34]. When combined with reduced space heat loads resulting from improved building fabric performance, such systems may become attractive.

It is likely that a range of different reactions and reactor designs will be utilised depending on the input energy source and temperature and required output power and temperature. For example, the requirements for small scale distributed space heating applications, industrial waste heat storage and concentrating solar thermal power systems will vary substantially.

Box SI 5.3. Storing solar thermal heat

Thermochemical storage is not limited by the same factors that influence other heat storage systems. The store surface area to volume ratio only influences sensible heat losses, which are a small fraction of the total energy stored, making thermochemical storage systems suitable for heat storage at both small and large scales over longer timescales. This makes them potentially a route for storing solar thermal heat generated at the building level from summer to winter, which could significantly reduce peak winter heat loads that need to be met from other sources. Small scale distributed storage in the building stock could provide several TWh of heat storage and contribute significantly to meeting the large peak space heat demand in winter.

Thermochemical heat storage is generally considered to be at an early stage of development with technologies validated in lab conditions at small scale generally for small numbers of cycles (TRL 1-4). Further research is required to develop materials, reactors and systems that can i) be charged in summer periods using heat from low-medium temperature solar thermal systems and discharged in winter to provide space heating, and ii) be used with high temperature concentrating solar thermal power systems to store heat for continuous power generation, which have been areas of active research over recent years.

5.5 Liquid Air Energy Storage (LAES)

Losses

Cryogen vaporization causes self-discharge at rates which will vary. They may be as low as 0.1%[35] or as high as 3% of the container's volume per day. Recent studies of cryogen carriers for LNG[36] use a vaporization rate of 0.08% per day equivalent to an 8% loss in 100 days. As with other technologies, there will be additional energy losses in charging and discharging processes.

Charging and discharging

Round trip efficiency for a LAES without energy recovery may be up to 35%, with charging up to 50% efficient and discharging up to 75% efficient, depending on scale. However, if the released 'cold' from the discharge process can be effectively recovered the round-trip efficiency of LAES can increase up to 55%. Supplying additional heat from a waste heat source at 150-200°C can increase electricity generated to 70-80% of that initially used to charge the store. Ideally LAES is suited to short/medium-term storage with large numbers of annual cycles.

Potential Scale

The integration with waste heat recovery (e.g. industrial processes), or perhaps waste cold recovery (e.g. from LNG regasification), is critical to improve the overall performance of LAES systems, although such integration will reduce operational flexibility. LAES is at TRL 7-9 with prototype systems being installed and demonstrated at scale[37]. Further research is needed to develop more efficient and cost-effective heat and cold storage technologies and also to develop new liquefaction processes for LAES applications.

One of the largest cryogen storage units (Segas LNG plant, Damietta Port in Egypt) has a storage capacity of 150,000 m^3, which would store 20 GWh of energy if used in LAES. 50 such plants would provide a TWh storage capacity.

Capital Cost

The power cost could be in the range £850 (the lowest value found in an assessment by Hamdy et al[38]) – 2500/kW, with costs towards the upper end of this range for the first plants and potentially at or below the bottom of the indicative range as the technology matures, with estimated total storage costs (liquid air, hot and cold stores) in the range £200-500/kWh.

5.6 Gravitational Storage

Pumped Hydroelectric Storage

According to the International Hydropower Association '*Despite an estimated 2.4 GW of viable hydropower potential in the UK, hydropower expansion is likely to be limited to small-scale applications (up to 5 MW), with the exception of pumped storage projects*'[39]. Planned and proposed projects include a 1.5GW, 30GWh pumped hydroelectric system at Coire Glas[40].

A 2013 JRC report[41] assessed the pumped hydroelectric storage potential in the EU and candidate countries for two scenarios in which reservoirs within 20 km could be interconnected, the first assuming that only existing reservoirs would be used, the second adding the possibility of connecting an existing reservoir to a new one. The UK's realisable potential is described in the Report. For all the countries studied, the realizable potential storage capacity was found to be 29 TWh (of which only 15% was in the EU: 20 TWh were in Turkey) in the first scenario, and 80 TWh (33 TWh in the EU) in the second (for comparison, some 3,300 TWh of electricity was generated in the EU in 2018).

The potential of the significant pumped hydroelectric storage capacity of Norway, which has by far the largest installed hydro-capacity of any country in Europe, to provide long-term storage for the UK or EU is often discussed. In 2020 Norway's capacity for hydroelectric power was approximately 37.7 GW from 1690 hydropower plants, including 1000 reservoirs providing a storage capacity of more than 87 TWh with a total of 154.2 TWh generated[42]. The pumped hydroelectric storage was 1.43 GW in 2019[43]. Norway's potential pumped storage capacity is 0.75 TWh in the first JRC scenario, and 13.3 TWh in the second. As discussed in SI 2, a UK-Norway 1400 MW interconnector came into operation in July 2021 while a second 1400 MW link is due to be completed in 2023. However, other European countries are also installing interconnectors which will lead to competition for access to Norwegian storage capacity, and Norwegian exports of hydropower are vulnerable to droughts.

Other Gravitational Storage

Gravitricity[44] has carried out tests using two 25 t weights in a 15 m tower at Port Leith, Edinburgh, and is now developing a number of project sites at existing mines in several countries. The company is considering weights of 'up to 12,000 t', which would each store 33 MWh in a 1 km shaft.

Energyvault[45] has built an 80 m demonstrator, in Switzerland, that uses a crane to lift 35 t weights. Construction of a 100MWh system started in China in March 2022. They claim over 85% round-trip efficiency.

ARES[46] (Advanced Rail Energy Storage) is building a 50MW energy storage facility in Nevada, that will employ a fleet of 210 cars, weighing a combined 75,000 tons, operating on 10 multi-rail tracks. The ARES web site refers to multiple 5MW tracks that can vary in size from 5 MW to 1 GW of power and 'an equivalent range of energy (MWh to GWh) depending upon weight and number of mass cars, slope and distance'.

Heindle Energy[47] and **Gravity Power**[48] are developing the using hydraulic power to lift a piston in an underground shaft.

5.7 Conclusions

Comparative Characteristics and Areas for further research

The characteristics of the storage technologies caused in Chapter 5 and in SI 5 are summarised in Table SI 5.4 together with aspects that would benefit from further research. Public acceptance will vary depending on the technology, context, potential impacts and location in which any storage technology at the scales anticipated is introduced.

Table SI 5.4 *Key characteristics and research requirements of non-chemical energy storage technologies*

Technology	Application	Potential Capacity	Unit Capacity	Potential Efficiency	Duration	Indicative target loss rates from storage	Research requirements
Compressed Air Energy Storage	Power	TWh	MWh-GWh	High	Medium (Limitation on duration is economic)	Compressed air → 0 Heat < 0.1%/day	Large scale demonstrator Cavern design and operational limitations System optimisation including thermal storage integration Actual system efficiency determination Assessment of potential national capacity considering potential conflicting applications and environmental restrictions
Thermal Storage	Power	TWh	MWh-GWh	High	Medium (Limitation is economic)	< 0.1%/day	Materials for high temperature storage applications Large scale storage system designs Assessment of optimal storage size and operational regimes Actual system efficiency determination Assessment of potential national capacity and appropriate sites Large scale demonstrator Assessment of Heat – Heat – Electricity applications Assessment of Electricity – Heat – Electricity applications
	Heat	TWh	kWh-GWh	High	Medium-Long	< 0.1%/day	Materials and system development Compact storage solutions Large scale store design and operational optimisation Interaction between central and distributed storage Actual system efficiency determination Determination of role in multi vector energy systems optimisation
Pumped Thermal Energy Storage	Heat Power	TWh	kWh-MWh	High	Medium	<0.5%/day	Prototype demonstrator Actual system efficiency determination System operation optimisation System scale optimisation
Thermochemical Heat Storage	Heat Power	TWh	kWh-MWh	High	Long	→0 after initial sensible heat loss	Materials and systems development Actual system efficiency determination Prototype demonstrators at different scales

Liquid Air Energy Storage	Power	TWh	MWh-GWh	High	Medium (Limitation on duration is economic)	Liquid air 0.1%/day Heat 0.1%/day	Large scale demonstrators Large scale system design and operational optimisation Actual system efficiency determination
Compressed CO2	Power	10 -100 GWh in GB	50 -200 MWh	70%	Hours-days	< 0.1%/day	

Potential capacity: based on materials availability and potential sites for each of the technologies could be multiple TWh,

Unit capacity: based on potential individual unit size

Potential efficiency: dependent on storage duration and scale. Specific figures given in the text.

Duration Medium: 1-10 Days, Long - Months

Heat storage losses are strongly dependent on store volume to surface area ratio with loss rate decreasing with increasing store size. Greater levels of thermal insulation are required for smaller stores to achieve low loss rates.

Annex SI5 1 Wind Integrated Storage

Mechanical energy gathered by the rotors of wind turbines could be converted directly into a storable form, which would subsequently be converted to electricity, by using it to

- pump water (or lift material) to a higher elevation,
- heat a thermal store,
- compress air, or
- pump heat, provided by compressing a gas, between cold and hot stores.

In such wind integrated storage the costs and losses involved in converting rotor power into electricity would be avoided. The general principles have been described by Garvey et al[49], while specific examples have been the subject of numerous patents and articles[50,51,52,53]. Integrating pumped water and compressed air storage would obviously require suitable geographical/geological conditions adjacent to the wind turbine.

Integrating storage with wind farms will involve additional costs, especially offshore, that would have to be balanced against the potential advantages. It is, however, quite possible that it would be worthwhile installing integrated pumped heat storage and possibly ACAES (which appear to be the most promising options). This possibility deserves further investigation, as does the possibility of integrating storage with nuclear reactors.

Annex SI5 2 Compressed CO2 Storage

A new technology that stores energy in compressed CO2 is being developed by the company ENERGYDOME[54]. It aims to provide both high energy storage densities and roundtrip energy storage efficiencies of over 70%. In the charge cycle CO2 is withdrawn from a large volume dome shaped CO2 gas store, compressed using electricity from the grid (at times of low cost) using a multistage compression system, cooled to ambient temperature and stored in liquid form at 70 bar. Heat recovered during the compression process is stored in thermal stores. In the discharge cycle, liquid CO2 is heated using heat from the thermal stores and expanded through a multistage turbine to generate electricity, with the CO2 gas returned to the dome shaped CO2 gas store. The advantages of this approach compared to compressed air energy storage are that the energy storage densities for similar pressure levels are much higher, with values of 66.7kWh/m3 quoted, and compared to liquid air energy storage are that the stores operate at ambient temperatures with no requirement for cryogenic storage. Due to these advantages the costs of long-term storage using the ENERGYDOME approach can potentially be lower. The first demonstration project of the ENERGYDOME technology was launched in Sardinia Italy in June 2022[55]. Plans for a 20MW-200MWh plant are in preparation with anticipated deployment date in 2023.

A plant capable of storing 200 MWh of compressed CO2 at 66.7kWh/m3 would require a dome with a volume of slightly over 106 m^3 to store the gaseous CO2 at ambient pressure, which is assumed. For simplicity, if a box-like structure 50 m high were considered (instead of a dome) it would occupy 4 hectares. While this is small compared e.g. to the area of a large solar farm, the volume required to store the gaseous CO2 limits the scale on which this technology could be deployed. To store 1 TWh would require the same volume as some 2,000 Amazon warehouses, covering 200 km2 if 50m high. It is difficult to image such large volumes being deployed in GB, which is not to say that compressed CO2 storage could not play a significant role.

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SI 6 Synthetic Fuels for Long-term Energy Storage

1. Introduction

As discussed in Chapter 1 of the Report, long-term energy storage needs are currently largely provided by storing chemical energy in carbon-hydrogen bonds in fossil fuels. SI 6considers the potential of non-fossil C-H bonds in synthetic fuels as stores of energy. The energy contained in these bonds can be released on demand to provide heat or electricity using existing infrastructure and technologies, in a way that minimises net emissions of CO_2[i].

Synthetic fuels of interest include:

- Gaseous synthetic fuels, such as e-methane, produced by electrochemical and thermochemical processes.
- Liquid electrofuels (e-fuels) produced from hydrogen and captured CO_2, including hydrocarbons made using the Fischer Tropsch (FT) process, and methanol; and
- Liquid organic hydrogen carriers (LOHC) in which hydrogen can be loaded and unloaded from organic molecules.

These systems can be considered as carbon-containing hydrogen stores, conceptually similar to ammonia's potential role as a nitrogen-based hydrogen store. Synthetic hydrocarbons typically provide the ease of transport and energy density of fossil hydrocarbons, and in some cases can be a drop-in replacement, thus leveraging generations of innovation in the combustion[ii]. In common with ammonia, the additional process steps in combining hydrogen with carbon reduce overall efficiency and increase costs. With the exception of LOHCs, synthetic fuels produce CO_2 in the energy release process, hence would need carbon capture (with the long-term storage or recycling of the CO_2). Biogenic carbon sources or direct air capture of CO_2 are likely to be regarded as carbon-neutral, but a full and transparent life cycle analysis is required in every case[iii].

The ability of any synthesis process to follow fluctuations in the availability of green hydrogen is key to the process economics. If the synthesis process cannot alter its production rate rapidly, then upstream storage of green hydrogen will be necessary. In the extreme, all of the hydrogen produced would need to be stored to ensure a steady flow of feed stock to the synthesis process, thus removing the key driver for synthesising energy carriers, which is to reduce storage costs compared to hydrogen. Hydrogen storage costs can be very significant[iv, v, vi].

2 Technologies for long-term synthetic fuel energy storage

2.1 Liquid electro-fuels

Electrofuels or e-fuels are synthetic fuels manufactured using captured carbon dioxide or carbon monoxide together with low-carbon hydrogen[vii]. They are termed electro- or e-fuels because the hydrogen is obtained from low-carbon electricity sources *e.g.* wind, solar and nuclear power. They are also known as power-to-gas/liquids/ fuels (PtX) or synthetic fuels. **Error! Reference source not found.** shows how they are produced[vii]. The principal advantages of e-fuels are that being hydrocarbons, they have a relatively high energy density and can be stored and distributed using existing infrastructure.

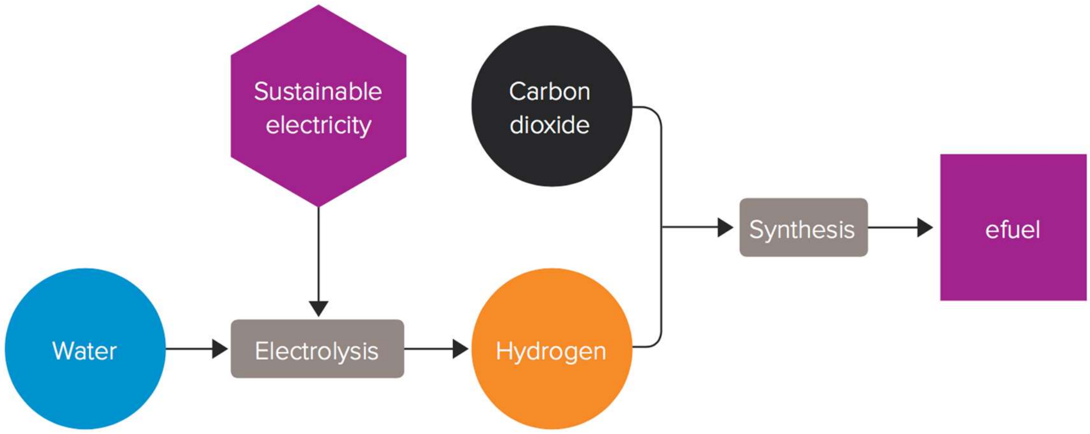

Figure SI 6.1 production of e-fuels using low temperature electrolysis

These fuels could be produced using modified versions of processes already in operation at very large scale. For example, methane[viii,ix,x] and methanol synthesis[xi,xii,xiii] require some modification for a CO_2-only feed but do not require further demonstration. Liquid hydrocarbons can already be made by Fischer-Tropsch synthesis but for low temperature processes, the CO_2 must first be reduced to CO in the reverse water gas shift reaction with hydrogen. This reaction is thought to be feasible but has yet to be demonstrated at scale.

The use of CO_2-rich feedstocks inevitably leads to reduced yield of hydrogen compared to current practice because of the need to activate CO_2 by chemical reduction, and the need to carry out the reaction at elevated temperature. There are already a number of e-fuel demonstration processes either on-line or in preparation[xiv,xv].Case studies are available in the Royal Society Policy Briefing, *Sustainable synthetic carbon-based fuels for transport*[vii].

E-fuel economics are driven strongly by the cost of low-carbon electricity, the cost and efficiency of the electrolyser technology to convert the electrical energy to chemical energy (hydrogen), and the cost of provision of CO_2 feed stock, which is often driven by carbon capture technology [xvi, xvii, xviii, xix, xx] and also by storage costs if caverns are not available[xxi].

Future advanced processes to produce e-fuels which may reduce cost significantly if successful, include reactions using photo-catalysis which involves the direct use of sunlight in the synthesis reactions, or co-electrolysis of CO_2, which is discussed in more detail below. Photo-catalysis is showing some promising results within the laboratory, as discussed in a Royal Society briefing document[xxii] but is presently limited by low-yields and reaction rates. Photo-catalysis is likely to remain limited by solar radiation intensity and the limited part of the visible spectrum which is useable in the chemical reactions[xxiii].

Sources of carbon

Point source emissions represent the lowest cost sources of CO_2 today. Carbon capture from flue gas at natural gas burning power stations, which is widely promoted as a means of reducing GHG emissions, is a possible source. However (as discussed in Chapter 2) i) some 10% of the CO_2 escapes capture and ii) upstream leakage of methane also has an important climate impact, and this report is based on the premise that non-fossil sources of electricity will continue to gain market share, regardless of the use of CCS. Hence, CO_2 captured from flue gas from fossil fuel combustion will not be considered further in this analysis.

Of the emissions produced by present-day UK industry (cement, steel, chemicals and refineries), roughly 35 $MtCO_2$ per annum, which would provide ~100 GWh(e)[xxviii] of energy storage, may be available for utilisation or storage by 2025 [xxiv]. As industrial point sources are replaced by decarbonisation at source, CO_2 will have to be provided in the future by biogenic sources, or direct air capture (DAC)[xxv, xxvi, xxvii, xxviii].

Biogenic sources of CO_2 could include the production of bio-fuels by gasification, enhanced by green hydrogen (Figure SI 6.2)

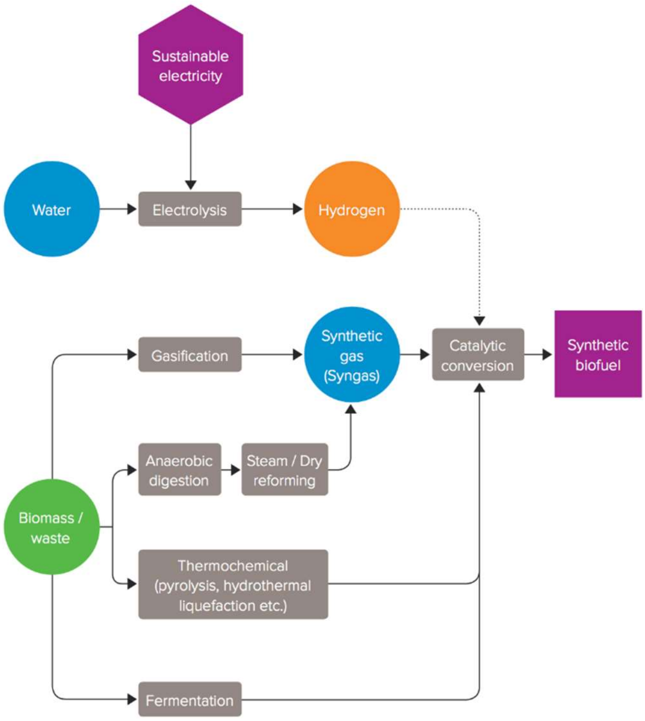

Figure SI 6.2: Production of Synthetic biofuels by gasification enhanced by Hydrogen.

Conversion of CO_2

Currently, e fuel processes either consume CO_2 directly, with some process disadvantages, as is the case for methanol, or require a separate step to convert CO_2 to CO, which is the required feed stock for low temperature FT processes.

Co-electrolysis of water and CO_2 using high temperature solid oxide electrolysis (550 – 850°C) offers higher efficiency than low temperature electrolysis and has the great advantage in the context of synthetic fuels that carbon dioxide and water can be simultaneously reduced to form syngas (CO + H_2) in a process called co-electrolysis [xxix,xxx,xxxi].

In addition to the efficiency benefits, high temperature co-electrolysis allows the process equipment to be greatly simplified compared to today's low temperature electrolysis schemes. Scale up of the solid electrolyte remains a significant barrier to entry for this technology, but if that issue can be overcome, co-electrolysis could help to transform e fuel economics in the future.

2.2 Liquid organic hydrogen carriers

Reversible energy carriers which can be recycled through reversible hydrogen loading/unloading processes are a promising option for long-term energy storage[xxxii],

[xxviii] Assuming 55% energy efficiency (LHV basis) for kerosene-type synthetic fuel to power

especially when used in combined heat and power applications[xxxiii]. Cost and performance of this system have been analysed by a number of authors[xxxiv,xxxv,xxxvi]

Liquid organic hydrogen carriers (LOHC) are one such example in which an organic hydrogen-carrying liquid is not consumed but cycled between many hydrogenation-dehydrogenation cycles. Many systems have been described in the literature with promising candidates including toluene/methylcyclohexane (Figure SI 5.3), complex aromatic hydrocarbons and *N*-ethylcarbazole/perhydro-N-ethylcarbazole.

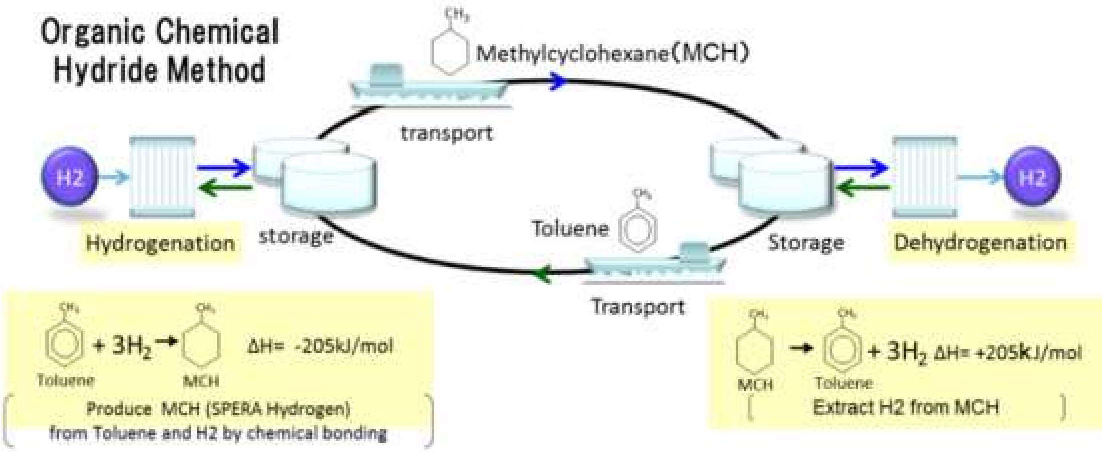

Figure SI 5.3 : Energy storage via hydrogenation-dehydrogenation of a LOHC[xxxvii]

The advantages of LOHC's include low-cost storage of the loaded hydrogen carrier which is a liquid hydrocarbon in conventional low-pressure tanks, and the avoidance of carbon capture from flue gas in the power generation step.

LOHC's have particular promise where combined heat and power is required, especially at the building or district level. The energy flows for one such concept are depicted in the Figure SI 6.4 below (based on[xxxiii]) :

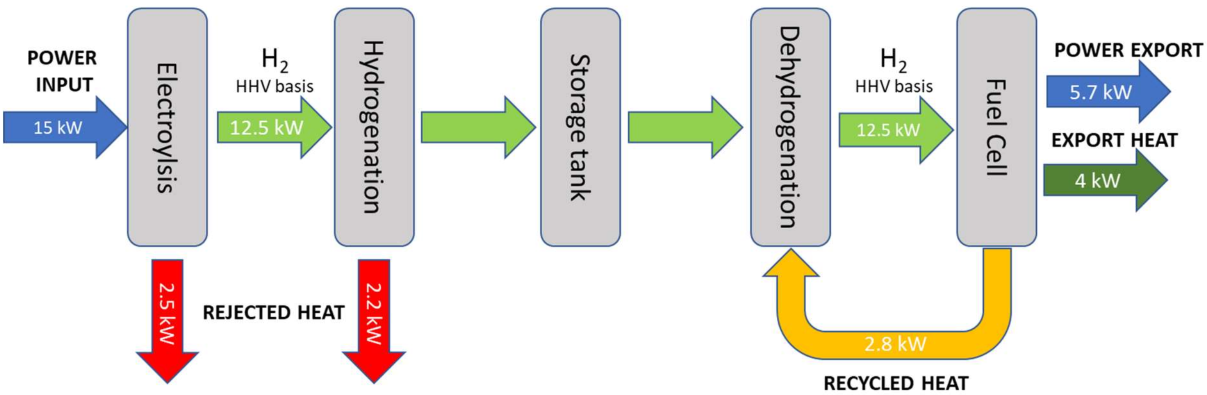

Figure SI 6.4 : Decentralised combined heat and power energy concept for LOHC

All LOHC's have the feature that energy must be removed from the system during the loading cycle, equivalent to about 20-30% of the energy content of the hydrogen, and then supplied to the system at a higher temperature during the hydrogen release cycle. This leads to system efficiency losses, which can be mitigated if the energy required for the decomposition is available as stored heat (e.g. molten salt) derived from resistive heating using surplus renewable power, or as waste heat from an industrial process, although the temperatures required for regeneration are above those normally considered as waste heat.

3 Technology Comparisons

1.6.1 **3.1 Round trip efficiency**

Figure SI 6.56.5 below[xxix] shows the round-trip (from electricity to create electricity) efficiency for hydrogen, ammonia, synthetic methane, methanol, FT liquids and LOHC's as energy vectors. Underground gas storage is assumed to be available for hydrogen, CO_2, and methane, and power generation is assumed to be local to the point of storage, so distribution losses are minimal.

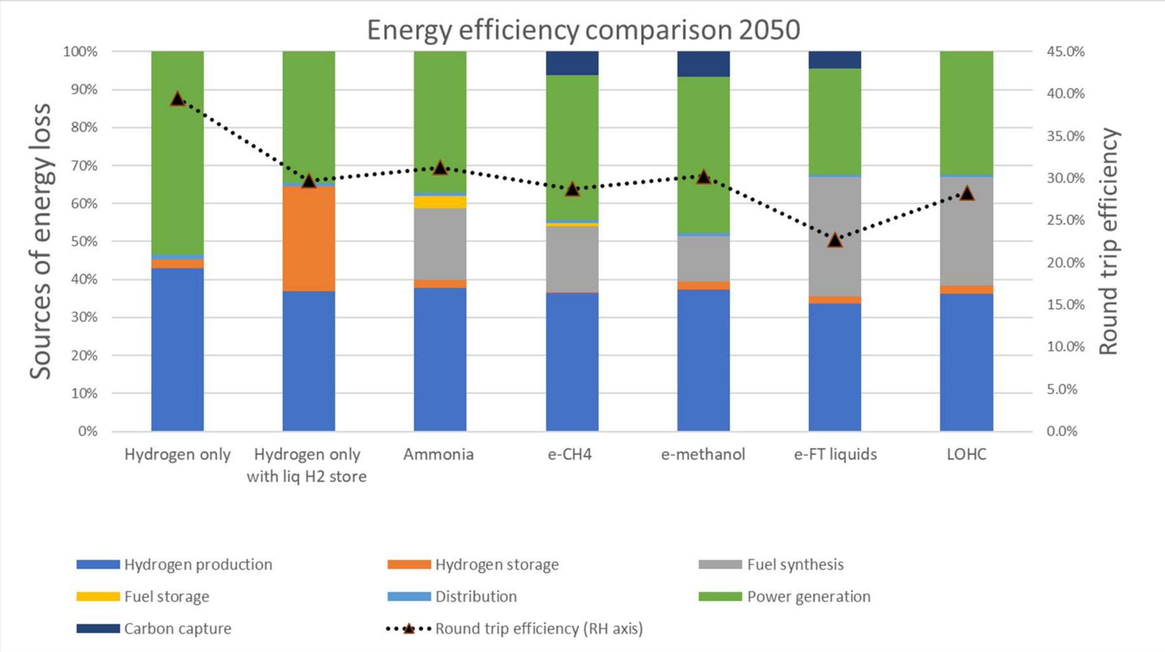

Figure SI 6.5 : Round-trip efficiency for hydrogen, ammonia, synthetic methane, methanol, FT liquids and LOHC's as energy vectors.

For this simple value chain, where large scale underground hydrogen storage is available, and there is no distribution loss, the additional process steps and carbon capture required for synthetic fuels incur significant round trip efficiency losses compared to hydrogen only. LOHC's may be able to match the efficiency of the hydrogen-only cycle if waste heat is available, but in reality, the regeneration step needs heat at temperatures too high to be regarded as waste, and heat storage would likely be required as the regeneration step is synchronous with electricity generation.

[xxix] Assumptions for the chart:

1. All power generation is by fuel cell in 2050
2. Ammonia, methanol and FT assumed not to be flexible with respect to load, so hydrogen is stored
3. LOHC and methanol assumed to be flexible with respect to loading (based on literature and Audi e-gas plant respectively)
4. Liquid hydrogen storage is above ground, not in a cavern
5. Electrolyser efficiency = 74% on LHV basis for 2050 (system, not stack, level, based on pervious RS synthetic fuels briefing paper)

3.2 Cost comparison

Costs of the various storage options have been modelled for the case discussed in Chapter 4, namely 60 TWh_e system storage (without contingency) requirement with 100 GW_e peak power generation capacity. The option in the charts below labelled 'Gaseous Hydrogen' is the same power-to-hydrogen-to-power option as that described in section 4.10, which in the conditions assumed there, gives a levelized cost of storage of £84/MWh ($113/MWh at £/$ exchange rate of 1.35).

For synthesis processes which are assumed to operate continuously (ammonia, methanol, LOHC and FT), then 10 days of hydrogen storage is assumed to be necessary to prevent supply interruptions. It may be possible to optimise the feed hydrogen storage requirements for these processes with detailed analysis of power availability patterns. The e-methane option analysis assumes no upstream hydrogen storage, again subject to optimisation. Figure SI 6.6 below[xxx] shows the estimated levelised costs of the various elements of the energy storage value chain, provided that gas storage in caverns is available. Note that the levelised costs in the chart below include capital and operations and maintenance (O&M) costs, but not the costs of input power generation:

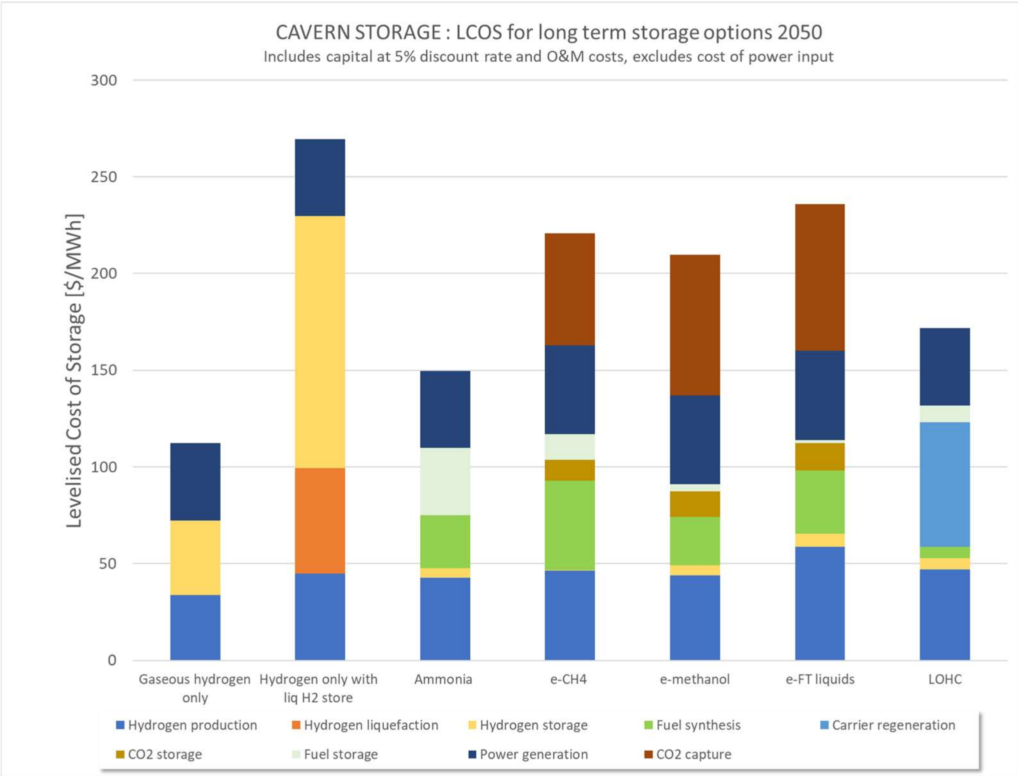

Figure SI 6.6 : Estimated levelised costs of the various elements of the energy storage value chain, provided gas storage in caverns is available.

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xxx Assumptions the same as those in efficiency chart plus :

1. 5% discount rate, 30 year financial project lifetime
2. Electrolyser costs = $450/kW, see Chapter 4
3. Utilisation =20% for electrolysis and 9.7% for power generation, in line with system modelling
4. Cavern costs based on H21
5. Where required, CO_2 is captured, stored (in caverns) and recycled to the synthesis plant
6. Methane is stored in caverns, although lower cost storage may be available in depleted hydrocarbon reservoirs
7. CO_2 losses are not reflected in the chart

Synthetic fuel production to store energy is expected to have levelised costs at least 50-100% higher than hydrogen-only energy storage. The synthetic fuel options generally incur significant additional costs for fuel synthesis and for CO_2 capture, storage and recycle, which are not offset by reduced hydrogen storage costs. LOHC's appear to offer slightly higher levelised costs than the hydrogen-only option with underground storage, trading off the cost of hydrogen storage against costs for process plant.

If cavern storage is NOT available, then gaseous hydrogen storage costs become much higher. Therefore, processes that can load follow the production of hydrogen to create a fuel that is easier to store are likely to have advantages over those processes that require invariant, steady state operation. Synthesis process flexibility is therefore expected to be a more important success factor than it has been historically, but this needs to be understood much better for individual process routes through demonstration at scale. Figure SI 6.7 below[xxxi] represents the estimated levelised costs where storage is all above ground:

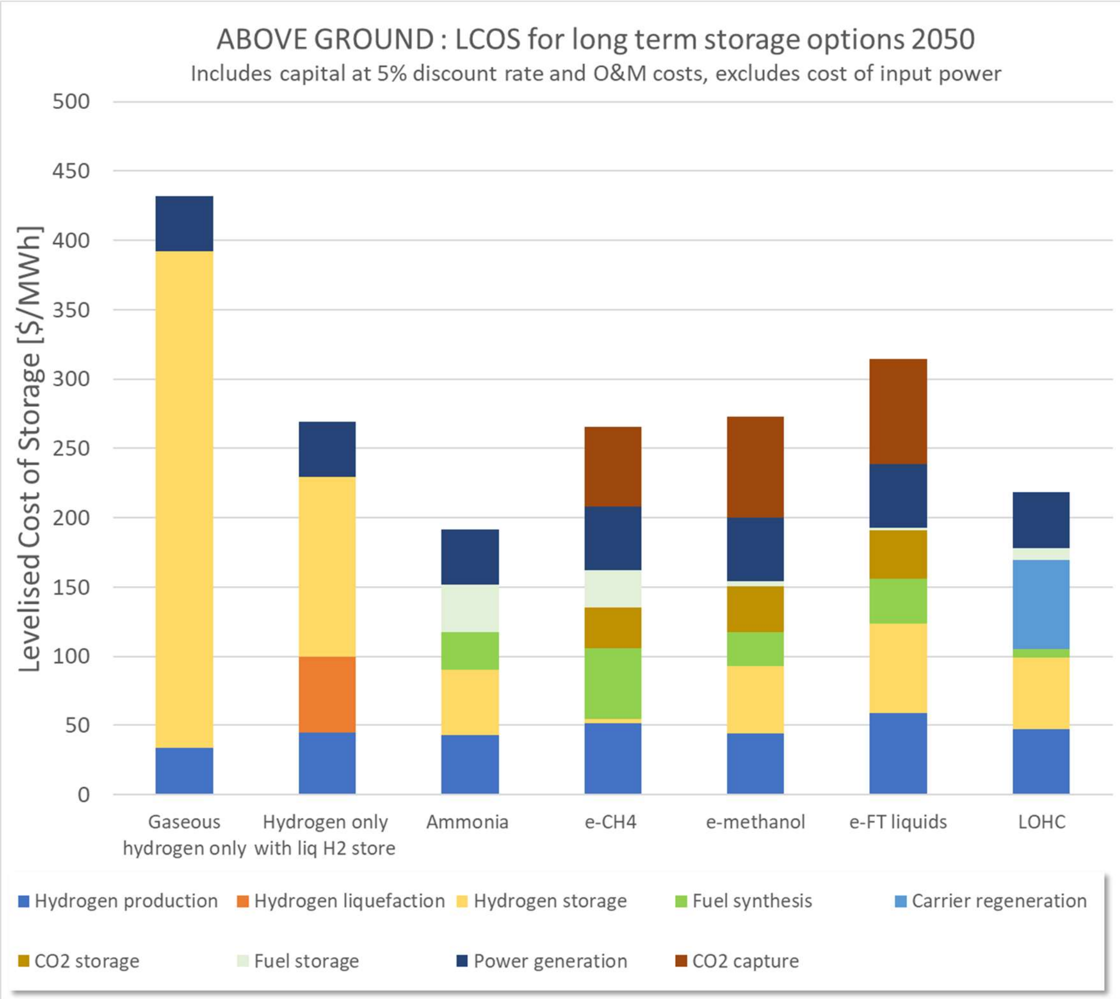

Figure SI 6.7 : Estimated levelised costs where storage is all above ground.

[xxxi] Assumptions :

1. Gaseous hydrogen in pressure vessels
2. Methane and CO_2 liquefied for storage
3. e-methane and LOHC only requires minimal H_2 storage, most storage is as methane or loaded LOHC respectively

Note that the absolute levelised costs for above ground storage are generally significantly higher than those for cavern storage. These costs can be minimised / eliminated if the conversion process is able to change its load to suit the availability of hydrogen, rather than operated at a constant throughput, thus avoiding hydrogen storage upstream of the synthesis unit. Thus ammonia, methanol, FT liquids and LOHC could see material reductions in their levelized cost of storage if they were able to operate dynamically across a full range of load, possibly with total shut down periods when hydrogen is not available.

4 Other factors affecting the choice of energy storage vector

The previous section assumes that power delivered to market is generated locally to the point of energy storage. The balance of merit between hydrogen and its derivatives can shift if power delivered to market is to be generated at some distance from the point of hydrogen generation. As discussed in section **Error! Reference source not found.**, hydrogen is difficult to transport, incurring high costs unless hydrogen transport pipelines are available, whereas liquid fuel transport costs are negligible in comparison.

The management of the carbon cycle for combusted synthetic hydrocarbons becomes more problematic over long transport distances as CO_2 would likely have to be captured and then stored underground, rather than transported back to the synthesis plant. As the storage of CO_2 underground is only likely to be socially acceptable offshore, power generation with CCS is likely to be confined to the North Sea and Irish Sea coasts.

One benefit of synthetic hydrocarbon fuels for energy storage is that they are likely to be more compatible with existing energy infrastructure and the existing fleet of CCGT power stations than hydrogen or ammonia, thus potentially reducing the societal cost of decarbonisation.

Table SI6.1 below is a summary of the attributes of the major chemical storage options against a set of performance criteria the assessment is relative rather than absolute:

Table SI6.1 : Summary of the attributes of the major chemical storage options against a set of performance criteria.

RANKING COMPARED TO HYDROGEN STORED IN CAVERNS

	Hydrogen	Liquid H2	Ammonia	e-methane	e-methanol	e-FT liquids	LOHC
Round-trip efficiency	1	4	2	6	3	7	5
LCOE	1	7	2	4	5	6	3
GHG emissions	1	1	1	4	5	6	1
Bulk transport costs	7	4	4	4	2	1	3

RANKING FOR ABOVE GROUND STORAGE

	Hydrogen	Liquid H2	Ammonia	e-methane	e-methanol	e-FT liquids	LOHC
Capital cost	7	3	2	4	5	6	1

The ability to cross energy sector boundaries, especially between power and transport, may affect the relative attractiveness of the options. For example, hydrogen fuel cell vehicles and hydrogen power generation could share infrastructure costs as both would benefit from hydrogen pipelines. Liquid fuels could be deployed in transport, especially aviation, as well as power generation, thus creating economies of scale across the two sectors.

3.3 Conclusions

The least cost solution for long-term storage of surplus UK electricity via chemical energy clearly depends amongst other things, on the availability of low-cost underground storage, the opportunity to use legacy distribution infrastructure and gas turbine power generation plant, and the distance to the power market.

- If salt caverns are available for hydrogen storage, and hydrogen and power generation are local to the point of storage, then adding a synthesis plant for ammonia, hydrocarbons, or liquid organic hydrogen carriers (LOHC's) appears to reduce efficiency and increase costs overall.
- If cavern storage is not available, then ammonia and LOHC's appear to be lower cost solutions than gaseous or liquid hydrogen storage. If ammonia and LOHCs can demonstrate process flexibility, thus reducing the cost of storing feedstock hydrogen compared to other options, they would be further advantaged over other options.
- If salt caverns are not available, and/or there is legacy infrastructure for natural gas transmission and use for power generation, then e-methane may play a role, provided that the carbon cycle can be managed in a cost effective and sustainable way.
- LOHCs could play a role in distributed combined heat and power systems.

Process flexibility is a key determinant of the merit order when salt caverns are not available because of the high cost of overground hydrogen storage. This is not an area that has been well explored in practice other than for e-methane.

The analysis indicates that e-fuels are disadvantaged both energetically and economically, regardless of the availability of underground storage, and are not promising candidates for long-term energy storage.

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S I 7 Electrochemical and Novel Chemical Storage

7.1 Electrochemical Storage

Material availability

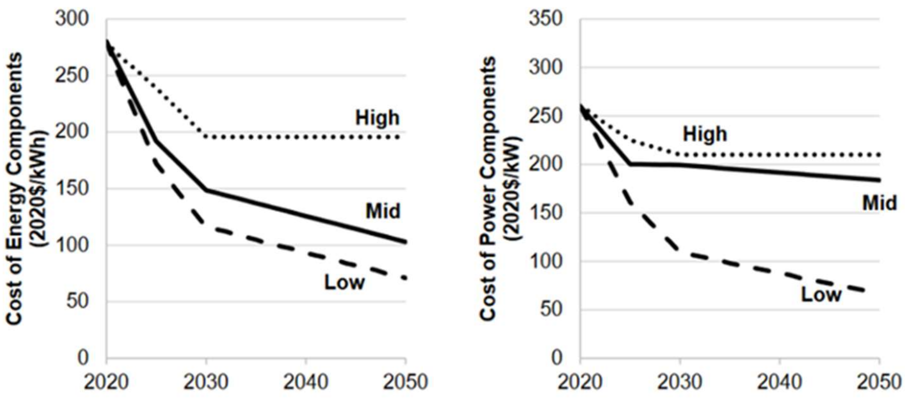
Large-scale deployment of lithium-ion batteries will result in increased demand for the raw materials, though the demand for lithium for electric vehicles (EVs) is expected to be greater (perhaps by an order of magnitude in the UK) than for electricity storage. Global resources should meet expected demand, but as the market rapidly expands, supply chains may become strained. Investment in recycling and second-life strategies is required to support sustainable growth[1]. The availability of cobalt, a component of most lithium-ion batteries, could be a more serious constraint, and there are concerns about its sources, although cobalt content has fallen from a third to 10% of the metal content of the unloaded cathode (and roadmaps for cathode chemistry predict further reduction in cobalt content) and lithium-iron phosphate (LFP) batteries are cobalt-free.

Costs

A 2018 paper by a group at the US National Renewable Energy Laboratory (NREL)[2] provided a bottom-up model of the installed costs of grid connected lithium-ion batteries, including the cost of land acquisition, permitting fees, interconnection, a transmission line fee, contingency, developer overhead, and profit. The model shows that the estimated capital cost of a 60 MW battery discharging in (or, equivalently, with [energy capacity)]/[power rating] of) 30 mins, 1 hour, 2 hours, and 4 hours can, to a very good approximation, be split into energy (/kWh) and power (/kW) components. A more recent NREL paper[3], based on a meta-analysis of a large number of estimates in the literature, gives the following mid-range estimates of the 2020 energy and power costs:

$$\$280/\text{kWh} + \$260/\text{kW}$$

This corresponds to a total of \$345/kWh (or \$1,380/kW) for a 4-hour battery. Note that **NREL define capacity as useable capacity** (i.e. the capacity after assuming that a charge controller limits the state of charge to between 10% and 90%[4]) per unit of energy delivered. The results of the metanalysis of future costs is shown in Figure SI 7.1



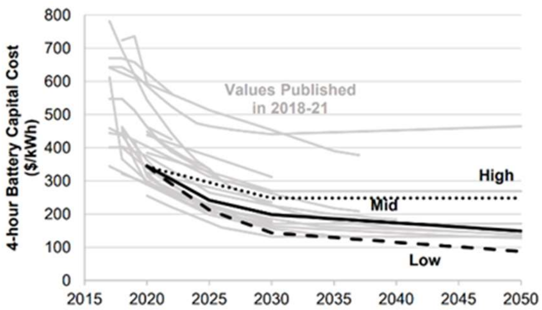


Figure SI 7.1 Results of a meta-analysis of projected capital cost of the energy and power components of a fully installed battery[3]. Note that the cost is defined here in terms of the useable capacity per unit of delivered energy, which is equal to the nameplate capacity [as normally defined] x (the depth of discharge)/(discharge efficiency).

The Low, Mid and High projections for the cost of a four-hour battery in 2050 are $86/kWh, $147/kWh and $245/kWh respectively. The last panel in Fig SI 7.1 suggests that the low projection is quite aggressive. Tesla is marketing 2 and 4 hour 3.9 MWh 'megapack' batteries[5] that deliver 1.9 MW and 1 MW respectively. The prices currently quoted for 1000 units to be delivered in 2024 are $428/MWh and $484/MWh for the 4 and 2-hour versions, including installation (and depending slightly on the location: these costs are for California). These prices are respectively 43% and 31% higher that NREL's mid projection for 2022, suggesting that NREL's cost estimates may be optimistic.

1. **The round-trip efficiency**. As discussed there, 90% is assumed in the report, which may be optimistic. A PNNL report[6] found 86%, falling 0.5%/year; the NREL meta-analysis above found a range 80-96%, and chose 85% as typical; Terna gave a range of 75-88% in 2017[7] ; a second NREL paper[8] gives 93.6% 'today' (2019) and 95.9% in the future; a recent review by another NREL group[9] gives 90% (these are full-system - AC to AC - efficiencies: many sources do not say whether the values quoted include rectifier and inverter losses, or if it is for DC to DC).

2. **Lifetime**. Many processes affect the durability of batteries including temperature, charging and discharging rates, and depth of discharge. Tests have found that an NMC battery held at constant ambient temperature cycled once a day with 74% depth of discharge would fall to 70% of its name plate capacity after 7.3 years (corresponding to 2,664 cycles)[10]. In calculating the cost of storing electricity in batteries it is assumed below that in 2050 **either**

- the number of cycles doubles to 5,328 before the capacity of a battery, operated with the limited depth of discharge assumed in NREL's meta-analysis, has dropped to 70% of its name plate value, and that the battery is used for 5,328 cycles or until 25 years have elapsed (which ever happens sooner). If cycled once/day, this would lead to a drop of 20.6% after 10 years, which is close to the 20% assumed by NREL[11] (this is based on NMC batteries: the performance of LFP batteries could be better),

or less optimistically

- that the cycle and calendar lifetimes are limited some 4000 cycles and to 15 years (little seems to be known about fade as a function of time rather than the number of cycles).

3. **Operation and Maintenance (O&M) costs**. It is generally agreed that variable O&M will be small (e.g. a PNNL analysis ~$0.3/MWh): it is assumed to be negligible below. The NREL meta-analysis found a range of Fixed O&M (FOM) costs and adopted a value (of 2.5%/year

of capex) from the high end, assuming that 'the FOM cost will counteract degradation[i] [12]'. This is discussed in another NREL report[13] which states that FOM costs 'include battery replacement costs, based on assumed battery degradation rates that drive the need for 20% capacity augmentations after 10 and 20 years to return the system to its nameplate capacity', which would only be possible if all fade were due to individual cell failures. The costs below assume steady degradation, and FOM of 0.5%, 1.5% and 2.5% of capex (2.5% should be seen as an upper limit if no attempt is made to restore capacity). Tesla[5] quote slightly over 0.2% for annual maintenance, to which operational costs should be added.

Combining these factors leads to the costs of delivering electricity from a battery (without the cost of the input electricity) shown in Figure 22 in the conditions described in the caption. Note that

1. With a fixed O&M cost (FOM) proportional to capex, the costs in Fig 8.2 obviously scale with capex. With NREL's high and low 2050 projections of capex they should be multiplied by a factor 1.66 and 0.58 respectively.

2. Unless O&M includes restoration of capacity (as assumed by NREL, but not here), the cost of operating expensive and cheap batteries would not be expected to be very different. With high values of capex it would therefore be natural to choose a relative low value of FOM as a percentage of capex, and vice-versa.

3. Some examples of sensitivity to the calendar and cycles lifetimes are shown in Figure SI 7.2. The left-hand panel shows that at high cycle rates the cost is not sensitive to the calendar lifetime (as it is longer than the cycle lifetime): for low cycle rates, the assumed calendar lifetime makes a big difference. The right-hand panel shows that for a given calendar lifetime, the cost depends on the cycle lifetime at high cycle rates (because capacity fades at different rates), but as the cycle lifetime decreases its importance decreases since fade is limited (and its effects discounted) before the calendar lifetime is reached (for 150 [75] cycles/year the cost with a 4000 cycle limit is only 2.1% [1.1%] higher than with a 5328 cycle limit).

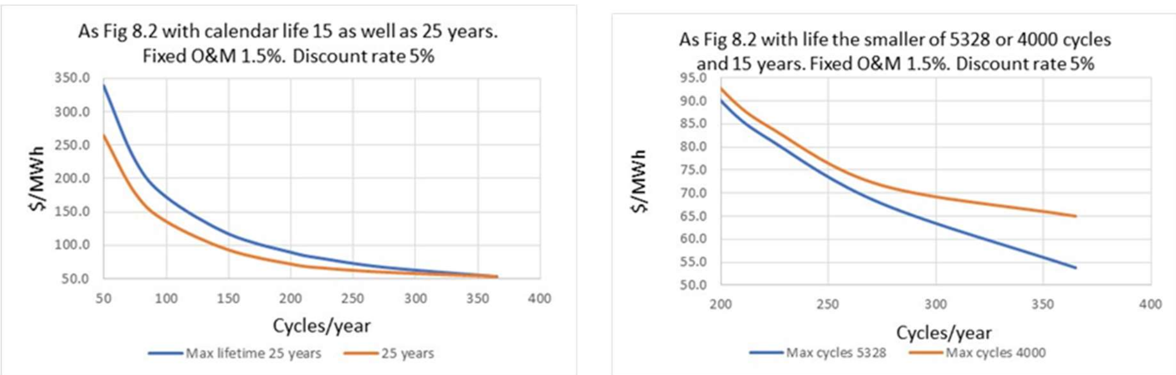


Figure SI 7.2

In the (obviously unrealistic) limit that the number of cycles/year become infinite, the cost of storing electricity tends to (the assumed capex)/(cycle lifetime)/(average fade over the cycle lifetime). With the mid value of capex, a lifetime of 5328 cycles and average fade of 0.85, this is $32.9/MWh. At realistic cycle rates, the costs plotted in Fig 8.2 are given by

$(32.9 + 31369*(cycles)-1.25)/MWh - for Fixed O&M of 1.5%, 5% discount rate

[i] The sentence goes on to say that 'the system will be able to perform at rated capacity throughout its lifetime', which is not possible.

$(32.9 + 32994*(cycles)-1.158)/MWh - for Fixed O&M of 1.5%, 10% discount rate

to a good approximation. These values are used as first input in studying the role of grid scale batteries in Chapter 9, after which the sensitivity is discussed.

Grid Connected Batteries in Electric Vehicles

Owners would have to be compensated for allowing their EV batteries to be used to support the grid, which would shorten their lifetimes - although as lifetimes are becoming much longer this may not be a serious problem.

State-of-the-art Li-ion batteries (typically NMC) in automotive applications are currently expected to survive around 1000 cycles before reaching 80% of their original rated capacity. As almost no vehicles ever achieve the corresponding mileage, there is a compelling case for considering the use of 'second life' EV batteries for stationary energy storage (this would be in competition with recycling their materials to make new first life batteries). A 70kWh automotive battery reduced to 80% of its original capacity would provide 56 kWh of energy storage capacity, and together a whole generation of second-hand batteries from 30 million cars would provide around 1.7 TWh. The prospect of many 100s of GWhs of storage becoming available at relatively low-cost is appealing, but the batteries would have to be effectively and safely selected and re-packaged, to avoid combining batteries that had been treated very differently during their first lives. Grid-scale battery operators would also have to consider the ongoing capacity fade of these batteries in their second life application, although control strategies and additional hardware could be devised to make the duty cycle less demanding than in automotive environments.

EV batteries should be designed for re-use and re-manufacture[14]. Their second life redeployment from demanding automotive applications to less demanding grid-scale storage applications (c.f. volumetric and gravimetric energy and power density requirements), provides a compelling opportunity for cost savings, as well as improvements to the battery circular economy. Two important points should be considered in this respect: manufacturing defects which could compromise cell safety are likely to manifest early in cell lifetime, and consequently these would not be observed in a second-life context. In contrast, safety issues that can arise due to the longer-term degradation (of materials) may pose a more significant risk in second life application. It is, therefore, critical to ensure the safety (and durability) of these cells for their effective redeployment, which in turn motivates research into the screening and qualification of batteries following their first life application. Current standards almost exclusively certify beginning-of-life batteries, and an effective second life battery market, would have to be supported by regulation (and associated standard/certification) to qualify batteries for safe operation in second-life applications.

Flow Batteries

The active components of the catholyte and anolyte (which may or may not be chemically the same) are atoms or molecules in different oxidation states. The ions, which are missing electrons or have additional electrons attached, are loosely bound to oppositely charged counter-ions provided by the aqueous acid or alkali in which the active components are dissolved. In the case, for example, of a vanadium RFB (currently the most common type), the active species are vanadium, vanadium oxide, and vanadium dioxide. When the battery is charged:

- at the negative electrode: $V^{3+} + e^- \rightarrow V^{2+}$, where the electron is provided by the power source and the vanadium is 'reduced', while
- at the positive electrode: $VO^{2+} + H_2O \rightarrow VO_2^+ + 2H^+ + e^-$, and the electron flows back to the power source and the vanadium is 'oxidised'.

Electrical neutrality is maintained by H^+ ions flowing though the membrane from the catholyte to the anolyte. When the battery is discharged, the reverse occurs.

A range of RFB chemistries are in development including all-vanadium, Zn/Br, Fe/Cr, HBr[15], and more recently organic RFBs, particularly those based on a class of compounds known as quinones, which emerged around 2014[16,17]. The most commercially mature is the all-vanadium design which is used here as an illustrative example. In RFBs the cross-over of anolytes and catholytes through the membrane can reduce the efficiency. However, in the all-vanadium design they are chemically the same. This means that while cross-over can cause cell imbalance (and capacity loss), cross-contamination is less problematic for the long-term health of the battery, as the system can be electrochemically regenerated without the need for complex chemical separations.

Capacity fade can be recovered, for example by electrolyte re-mixing, unlike in more conventional battery chemistries. Consequently, straight-forward capital cost comparisons (e.g. in \$/kWh) which are widely used to evaluate energy storage technologies, are not necessarily accurate metrics of lifetime cost, as they assume constant performance throughout installed lifetime, as discussed by Rodby et al[18] who provide a comprehensive techno-economic analysis of levelized cost of storage approach for V-RFBs.

7.2 Chemical storage

Choice of redox process and metals

Redox couples can also be employed to store energy through chemical processes. Metal oxides can be reduced to metals by using fuels as reducing agents. A full characterisation of these cases is outlined in an Annex to SI 7.

There are only a limited number of metal oxides that can be reduced by fuels, such as hydrocarbons, hydrogen, or syngas (a mixture of hydrogen and carbon monoxide), including the oxides of copper, cobalt, nickel and iron. Reduction by fuels such as hydrocarbons or syngas produces carbon dioxide, e.g. through the reaction,

$$\text{Metal oxide} + C_xH_y + \text{Thermal energy} \rightarrow \text{Metal} + x\,CO_2 + y/2\,H_2O.$$

In a net zero world, this carbon dioxide would have to be captured and sequestered (CCS), unless its release were deemed to be a tolerable price to pay for creating a reserve that would only be used infrequently. Electrochemical reduction is possible for oxides that cannot be reduced by common fuels because they do not provide enough energy.

Choice of oxidation process

Once reduced, the metal can then be stored in the absence of water and air for an extended period of time and, when desirable, re-oxidised. The oxidation process used would depend in part upon the prevailing energy system and desired energy product. For example, reaction with steam could be used to generate hydrogen or reaction with air to generate heat, with the metal oxide recovered in both cases. These oxidation processes can occur with a significant release of energy and it is important the safety of the systems is properly considered.

- With water

  Metal + Steam (H_2O) → Metal Oxide + H_2 + Thermal Energy

  This hydrogen could be used to produce power in a fuel cell (with hydrogen produced by steam methane reforming this would not be possible in PEM cells as it contains carbon monoxide which damages the cells' catalysts). Alternatively, it could be combusted and the hot exhaust gases fed into a turbine.

  The fraction of energy returned as heat (as opposed to hydrogen) is higher for those metals that can only be reduced electrochemically (the extra energy required to produce these metals can only be returned as heat). This will reduce the overall efficiency for these cases, unless the heat can be utilised.

- With air

  Metal + Air (O_2) → Metal Oxide + Thermal Energy

  The metals under consideration can be readily oxidised with air to generate heat in the form of hot exhaust gases. These gases would be fed into a turbine system to produce electricity.

The example of iron is presented in Box SI 7.1.

Routes to long term, large-scale novel chemical storage

It is possible to produce and stockpile metals to be used as energy stores over extended periods. Storing energy in metals, which would be relatively expensive and inefficient, is not expected to provide the main form of long-term storage. However, since metals are stable and easy to store, they could be used to produce hydrogen or heat to meet very occasional needs, such as a once in a decade cold snap and wind drought.

A reserve of iron could be created using some of the output of existing steel-making facilities. The UK currently produces more than 5 Mt of pig iron a year, which is the equivalent of about 7 TWh_{LHV} of stored energy (or 800 MW equivalent averaged over 1 year). Given a possible exceptional/once a decade need for storage on the scale of several tens of TWhs (thermal energy), additional facilities would be required.

The volume requirement for a 60 TWh iron thermal energy store would be approximately 20,000,000 m^3 (roughly the size of 5,300 Olympics swimming pools). This would not have to be at a single site, but the volume is nevertheless significant, and would further require controlled conditions, especially for long storage durations. Large particles of iron would degrade more slowly, but smaller particles (which would have to be kept under nitrogen or carbon dioxide) would release their energy/hydrogen more efficiently. Larger particles (a few cm) could be stored and then further processed before reaction, or smaller particles could be held in controlled (dry) conditions, though both would incur further cost.

Box SI 7.1 Iron as an Energy Store

Iron ore (normally a mixture of the iron oxides, haematite, Fe_2O_3, and magnetite, Fe_3O_4) is abundant and cheap and iron (Fe) is a comparatively stable metal. Given the well-established supply chains and processing practices for making iron, it provides a good example of the possible use of metals to store energy. The use of iron-making facilities would have the additional benefit of employing assets and a skilled workforce that is under economic pressure.

Iron is currently extracted from its ore, which typically costs around \$100/tonne, using syngas produced from coal in blast furnaces. Iron production could be decarbonised by modifying blast furnaces to capture and store carbon-dioxide, using electrolytically produced hydrogen as a reducing agent, or through direct electrolysis (as discussed e.g. in https://www.energy-transitions.org/wp-content/uploads/2021/12/MPP-Steel_Transition-Strategy.pdf).

While iron produced in any of these ways could be used as an energy store, 'chemical looping' (in which a metal produced by chemical reduction is oxidised, the oxide that is produced is then re-reduced to produce more of the metal and hence store more energy) provides an opportunity to generate hydrogen or heat (Figure 0.2). Any carbon dioxide produced may have to be captured for the process to be compatible with net zero.

Magnetite or haematite can be reacted with hydrogen to produce iron and water. The reverse reaction of iron with water vapour releases hydrogen and recovers magnetite (water is insufficiently oxidising to produce haematite):

$$3Fe + 4H_2O \rightarrow Fe_3O_4 + 4H_2$$

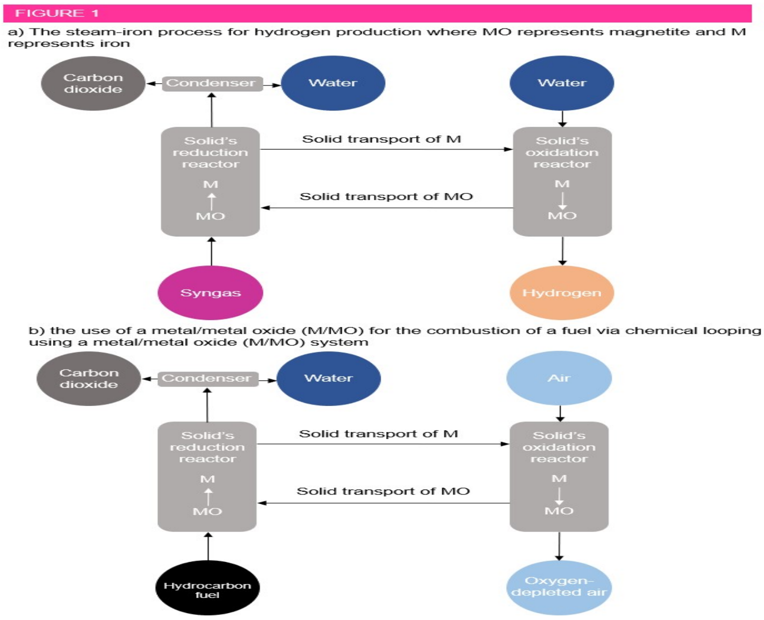


Figure 0.2 Chemical looping of iron

One tonne of magnetite could in this way be used to store 1.16 MWh thermal energy equivalent (LHV) of hydrogen, in a volume of 0.35 m^3, some 1000 times less space than gaseous hydrogen stored at atmospheric pressure, or three times less than hydrogen stored at 350 bar. To store 1 TWh thermal energy would require 0.9 Mt (53 Mt) of magnetite. To put this into perspective: 50 Mt of magnetite, which would cost some \$5 bn at the typical cost of \$100/tonne, is equivalent to roughly 1 tonne/person in the UK. Practically, iron ore can be shipped in quantities around 0.5 Mt per vessel and thus roughly 100 shiploads would be required to supply 50 Mt.

electrolytically produced green hydrogen is widely in use as an energy store, in transport, to provide heating, and/or as a source of ammonia, the proposed reserve of iron could be used to supplement supplies when they run low. The reserve of iron could also be used to generate electricity through complete combustion and use of turbines. In either case, investment in infrastructure would be needed, although no new infrastructure would be needed to store, distribute, and use the hydrogen and/or electricity that would be produced. Adapted gasification technologies for iron oxidation by water or air would require approximately 40 GW of installed capacity if the 60 TWh storage were to be used over approximately two months. Gasifiers are available at the GW scale and practical implementation would appear possible. The rapid discharge of the iron energy reserve (as opposed to iron generation which can be much slower, but over a longer period of time) does of course result in a much larger capital expenditure on this step. This capital expenditure is likely to be prohibitive if the equipment is additional to the existing energy infrastructure of the UK.

Control of particle size would allow the iron/iron oxide to be re-used over multiple cycles thus reducing the cost per cycle. For instance, if the iron could be employed over 10 cycles the cost per person of the initial investment in the iron ore would be $10 per person per cycle.

Other potential options

There are other possible energy carriers that would have to be produced electrochemically. For example, silicon produced using very cheap solar power could possibly compete with iron as a portable source of hydrogen for use in powering vehicles or ships (when oxidised with water, it produces hydrogen at a suitable pressure for storage in vehicles), or as a reserve energy store. These silicon/silicon oxide[19] and boron/boron oxide[20] systems have been studied as possible energy stores.

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ANNEX SI 7 Novel Chemical Storage

Novel chemical storage is defined here as the use of chemical reactions to store chemical or thermal energy and later release chemical or thermal energy but NOT through the storage of carbon, hydrogen or predominantly carbon- and hydrogen-containing fuels themselves.

Such systems can be separated into closed and open cycles. A closed cycle could involve, for example, a decomposition where all the products of reaction are stored with them later recombined through the reverse reaction. This will produce no useful chemical product and thus can only be used for thermal energy storage (closed systems and thermal energy storage are covered in

SI 5 Non-chemical and **Thermal Energy Storage**). Alternatively, in an open cycle the reductant, or the oxidant, or both, could be fed to the system and products may leave the system.

If the storage of hydrogen and carbon is dismissed (this eliminates, e.g., hydrogenation/dehydrogenation reactions for chemical energy storage) then open cycle chemical and thermal energy storage processes would appear to be confined to reduction and oxidation reactions (or perhaps hydration and dehydration reactions). Common reducing agents (fuels or reformed fuels) are gas phase as are oxidants (air or water vapour) in the temperature range that materials can undergo reduction and oxidation with reasonable kinetics. As the interest is in a chemical product rather than simply storing heat, it makes more sense to use a heterogeneous system to avoid separation costs. This leaves gas-solid, gas-liquid and liquid-solid reactions. Liquids have limited temperature ranges in which they are stable, so applications will tend to be highly specific; whereas gas-solid reactions can be much more flexible and will thus be the focus.

In summary, options are confined to storing chemical and thermal energy by reducing a solid phase (here called the carrier), releasing or using any product gases and then at some later stage re-oxidising the solid energy carrier and again releasing or using any product gases.

There are a number of alternative methods of reduction and oxidation of the carrier. Reduction could be performed with a primary fuel, a reformed fuel (or hydrogen), through thermal decomposition, or electrochemically. Reoxidation could be performed chemically or electrochemically using air, water, carbon dioxide. These processes can be operated continuously (conversion processes with no storage of the carrier) or in an interrupted storage mode. Reduction processes can be matched with oxidation processes to yield an overall process. SI A7.1 below combines five reduction processes with five oxidation processes, yielding 25 overall processes. The table also indicates whether the overall process has received research attention. Note that this table is not exhaustive and could be extended with further reduction and oxidation options.

Each reduction and oxidation process can also be shown on a flowsheet as an individual process. Reduction and oxidation processes can be combined to produce an overall process (note once more that this overall process can be operated continuously or in storage mode).

Figure SI A 7.1 and SI A 7.2 show the reduction and oxidation processes from Table SI A 7.

Reduction and oxidation processes can be combined to produce a cyclic redox process. The Figure in Box SI 7.1 shows the overall processes which are the subject of the main report operating in continuous mode with solid transport between the reduction and oxidation processes. The same processes can be operated in storage mode whereby the carrier is stored between reduction and oxidation. In general, a chemical reduction followed by a chemical oxidation is referred to as chemical looping. Chemical looping has received increased interest recently because, as an unmixed reaction, for example fuel and air can undergo reaction with separation of the carbon dioxide-containing stream from the oxygen-depleted air stream and thus facilitate carbon dioxide capture. There are a number of reviews that cover the use of chemical looping in energy conversion[1,2,3,4,5] and other[6] processes. Chemical looping has also been shown to permit higher conversions of water to hydrogen than in a conventional 'mixed' reaction process[7].

		Method of oxidation				
Method of reduction		Air (all generate thermal energy)	Water/steam (all result in hydrogen production)	Carbon dioxide (all result carbon monoxide production)	Electrochemical oxidation with air (all generate electrical energy)	Electrochemical oxidation with water (all generate electrical energy and hydrogen)
	Hydrocarbon fuel such as methane	Chemical looping combustion	Chemical looping reforming	Chemical looping dry reforming	Chemical looping fuel cell	Reforming with heat to electrical energy
	Reformed hydrocarbon fuel, i.e., synthesis gas	Chemical looping combustion with pre-reforming	Chemical looping water-gas shift with hydrogen separation for hydrogen storage using reformed fuels	Chemical looping reverse water-gas shift with carbon monoxide separation	Chemical looping fuel cell with pre-reforming	Shift and hydrogen storage with heat to electrical energy
	Hydrogen	Chemical looping combustion of hydrogen	Chemical hydrogen storage	Hydrogen storage but released as carbon monoxide	Chemical looping hydrogen fuel cell	Hydrogen storage with heat to electrical energy
	Thermal decomposition	Possible use in chemical heat pump	Hydrogen production through e.g. a solar-thermal route	Carbon monoxide production through e.g. a solar-thermal route	Heat to electricity	Heat to electricity with hydrogen
	Electrochemical reduction	Electricity to heat for e.g. off grid heat demand	A chemical looping electrolysis or hydrogen production	A chemical looping electrolysis or carbon monoxide production	Solid state battery	A chemical looping electrolysis or hydrogen production process

Table SI A7.1 Reduction and oxidation processes to generate overall processes. Colour codes, Green: Active area of research, Orange: Limited research, Red: Unexplored, Thick borders: Processes subject of main report.

FIGURE 1

The five reduction processes referred to in Table 1

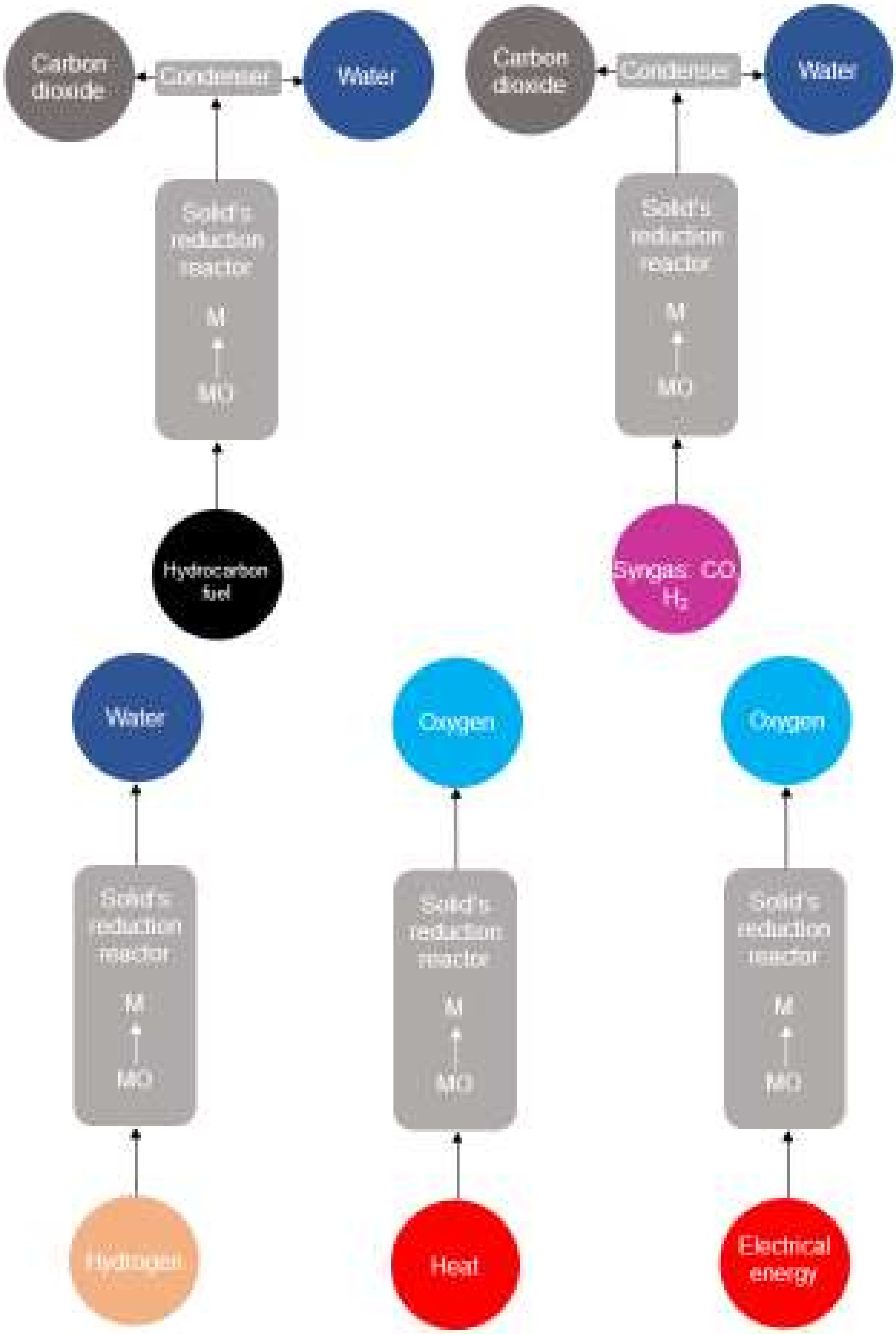

Figure SI A 7.1. Five reduction processes

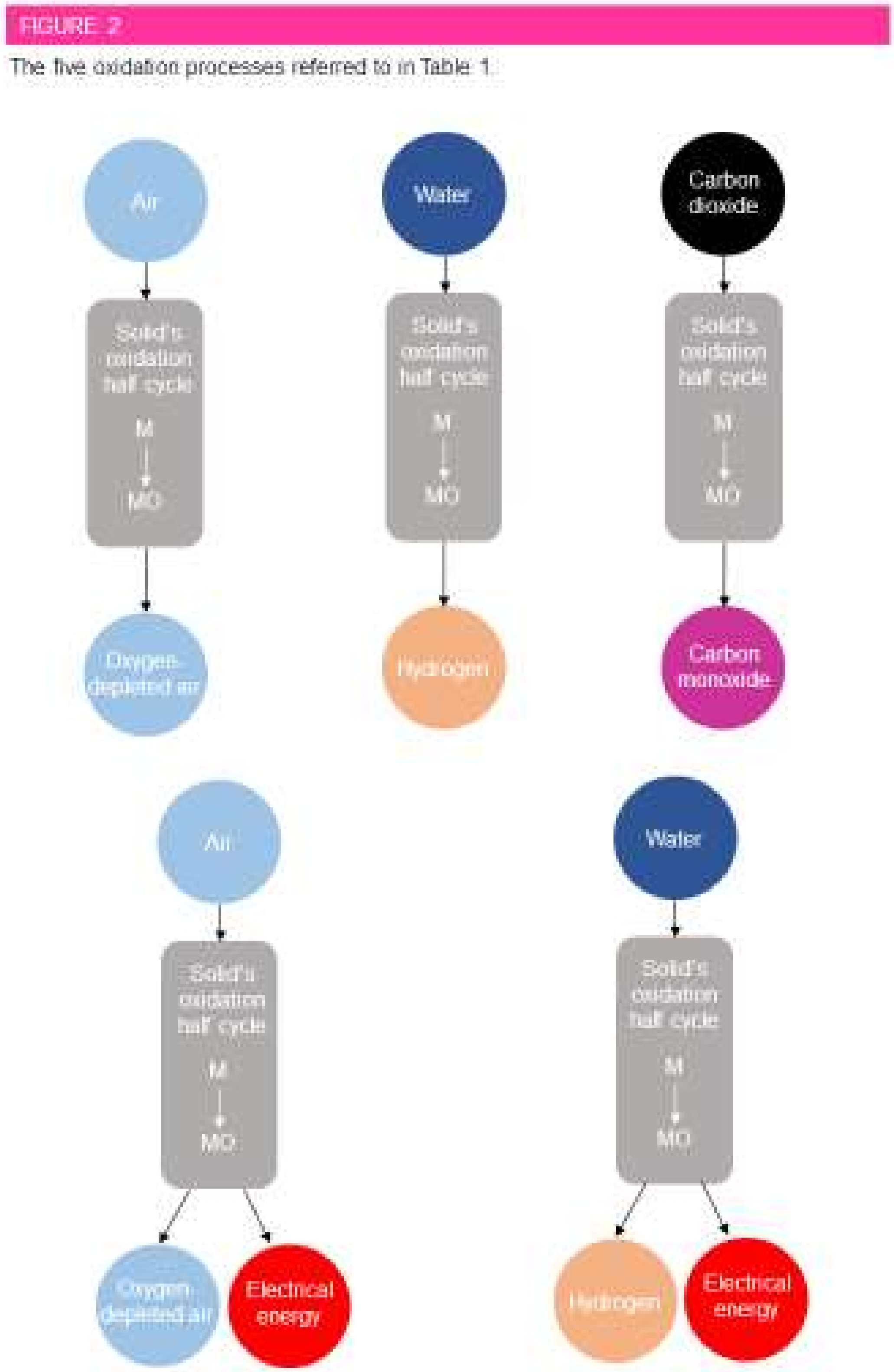

Figure SI A 7.3 Five Oxidisation processes

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SI 8 Powering Great Britain with Wind & Solar and Storage

8.1 Technology Choices

Cost of Ammonia storage

Fig SI 8.1 shows the average cost of electricity fed into the grid without the costs pf transmitting wind and solar power to store and providing grid services if i) all storage is provided by green ammonia and ii) it is all provided by hydrogen, with the base costs found in the report and the optimistic assumption that electricity can be generated from ammonia at the same cost and with the same efficiency as from hydrogen.

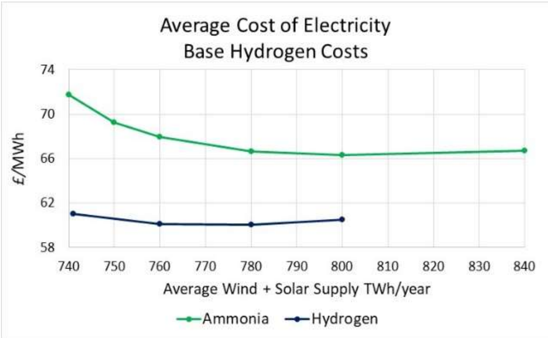

Figure SI 8.1 Average cost of electricity delivered to the grid by wind and solar supported by ammonia or hydrogen storage only, without the costs of transmitting electricity from wind and solar farms to storage and providing grid services, with the base costs, assuming that wind plus solar power costs £35/MWh and a 5% discount rate.

The difference between the minimum costs with ammonia and with hydrogen is £6.2/MWh. This difference narrows if high costs are used for electrolysers, hydrogen storage and power generation (from ammonia as well as hydrogen, which is assumed to cost the same) together with the central costs for ammonia synthesis and storage, but only (see Fig SI 8.2) to £4.40/MWh.

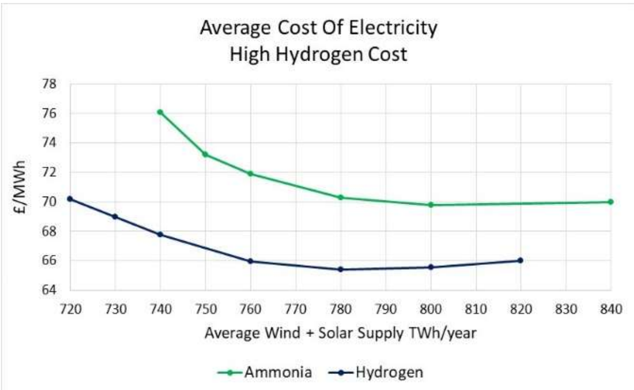

Fig SI 8.2 – As in Fig SI 8.1 but with the high hydrogen costs (which also affect the ammonia cost as explained in the text)

Given that the assumptions made in the Report on the cost of making ammonia were on the optimistic side, and that in reality generating power from ammonia is likely to be more expensive (a 10% increase would increase the difference in the costs of using ammonia and hydrogen by £0.44/MWh in the base cost case, or £0.57/MWh in the high cost case), the conclusion is that the use of ammonia rather than hydrogen to provide all storage would be at least £5/MWh more expensive, although this would be offset by any savings in transmission costs due to the fact that ammonia storage can be located anywhere.

8.3 Provision of all flexible power by a single type of store

Calculation of costs

Table 8.3 reported the annualised costs of providing hydrogen storage in terms of the capital and operational costs in Table 8.2. With fixed opex assumed to be proportional to capex, the annualised costs are given by

Capex x $(d/[1 -(1/(1+d)^N]$ + opex as fraction of capex)

where d is the discount rate (assumed to be 5% in Table 8.3) and N is the financial lifetime (a concept explained in SI A). Box SI 8.1 provides the results also for a 10% discount rate and for ACAES, with the input costs in Table 8.4, and for the cost of storage in batteries obtained by making a fit to Fig 7.2 assuming opex of 1.5% of capex.

Box SI 8.1 Costs of Electricity Provided by Storage and Other Assumptions

With the projected 2050 central/base values in Tables 5 and 7, and a fit to central values in Figure 23, the costs of delivering electricity from storage *(without the cost of the input energy)* are:

4-hour Li-ion batteries

At 5% discount rate £(21.4 + 23236*$(\text{cycles})^{-1.25}$)/MWh

At 10% discount rate £(21.4 + 21996*$(\text{cycles})^{-1.158}$)/MWh

The number of cycles/year = (average electricity delivered annual)/(useable capacity)/(discharge efficiency)

ACAES

At 5% discount rate **£**[(255 x maximum energy stored in TWh + 23.3 x (P_{in} in GW + P_{out} in GW))/(Annual output in TWh)]**/MWh**

At 10% discount rate **£**[(416 x maximum energy stored in TWh + 32.4 x (P_{in} in GW + P_{out} in GW))/(Annual output in TWh)]**/MWh**

Power ↔ Hydrogen

At 5% discount rate **£**[(26.7 x electrolyser power in GW + 32.1 x size of the store in TWh_{LHV} +25.2 x maximum power output in GW)/(Annual Output TWh)]**/MWh**

At 10% discount rate **£**[([40.3] x electrolyser power in GW + [48.4] x size of the store in TWhLHV +[38.1] x maximum power output in GW)/(Annual Output TWh)]/**MWh**

With base costs and a 5% discount rate, the average cost of electricity provided by a hydrogen storage and directly by wind and solar power (assuming that the redial surplus is curtailed) is

£[(26.7 x electrolyser power in GW + 32.1 x size of the store in TWh_{LHV} +25.2 x maximum power output in GW) + (average wind + solar supply in TWh)*(cost/MWh of wind + solar energy)/(Annual Output TWh)]**/MWh**

With a 10% discount rate it is

£[(40.3 x electrolyser power in GW + 48.5 x size of the store in TWh_{LHV} + 48.4 x maximum power output in GW) + (average wind + solar supply in TWh)*(cost/MWh of wind + solar energy)/(Annual Output TWh)]**/MWh**

Sensitivity to electrolyser and generation efficiencies

The efficiencies were assumed to be assumed to be 74% and 55% respectively. The effect of varying them by +/- 10% is shown in Table SI 8.1 in case that wind + solar costs £35/MWh with the base costs for electrolysers and generation **but** the low cost for the store (the percentage change in the bottom line is dominated by the change in the cost of wind and solar as the threshold increases, and is not sensitive to the cost of the store). If wind and solar cost £45/MWh, the bottom line in the right-hand column increases to 6.5%.

Efficiency in %	**74**	66.6	74	66.6
Efficiency out %	**55**	55	49.5	49.2
Round-trip efficiency	**40.7**	36.6	36.6	33.0
Threshold energy	**703.5**	722.5	722.5	742.2
Wind + solar = 741/703.5*threshold	**741**	761	761	782
£/MWh (not sold)	**58.7**	59.2	60.4	61.8
Increase in cost relative to 74%, 55% case	0	0.9%	2.9%	5.3%

Table SI 8.1 Cost of electricity for electrolyser or/and conversion efficiencies10% lower than assumed in Table 9.1 (the case in bold) for wind + solar generation at the same multiple of the threshold energy

Different Wind/Solar Mixes

It was found in Chapter 2 that, with the models of GB demand and wind plus solar supply used here, the fraction of this supply that can be fed directly into the grid to meet demand is a largest, and the initial surplus smallest, for a solar/wind mix of around 20:80. This does not necessarily mean that it produces the smallest or cheapest storage system, or the lowest average cost of electrical power, not least because solar energy is cheaper than wind energy. It does, however, mean that the amount of energy to be provided by storage is less at 20%, and the threshold at which store can meet demand is lower than at 10% and 30%, as shown in Fig SI 8.3

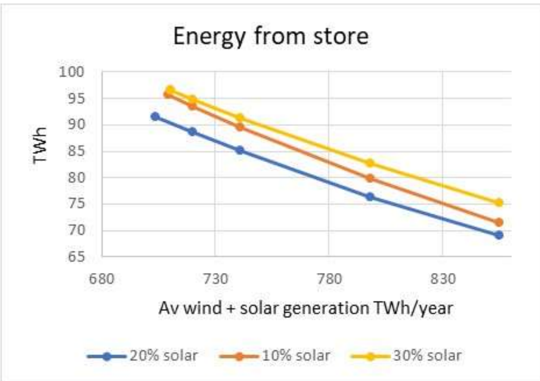

Fig SI 8.3 Energy to be provided from store as a function of wind plus solar generation (starting at the threshold at which all demnd can be met) for different solar/wind mixes

In their 'unconstrained study' Cosgrove and Roulstone[1] found that the mix of types of store stores changes significantly as the solar/wind mix varies between 10% and 30%. The impact of varying the solar/wind in the constrained case studied here is expected to be relatively modest as the hydrogen store is dominant, but this needs to be investigated properly. Pending an investigation, note that:

1. The interplay of the different factors is complex. An example is provided by the fact that, as shown in the Figure SI 8.4, at high levels of wind plus solar generation the minimum hydrogen store size occurs at 10% solar, although it would have to provide more energy than with 20% solar (this does not imply that the storage system would be the cheapest with 10% solar as the smallest store is generally not the cheapest). The reason is that at the minimum store size, 100% of all surpluses must be stored, and for a fixed level of wind plus solar generation the surpluses are smallest at low solar, as shown in Table SI 8.2. This is because the largest surpluses occur when high wind and high solar coincide, and while peak solar increases by a factor of three as its contribution increases from 10% and 30%, peak wind only decreases by 22% as wind decreases from 90% to 70%.

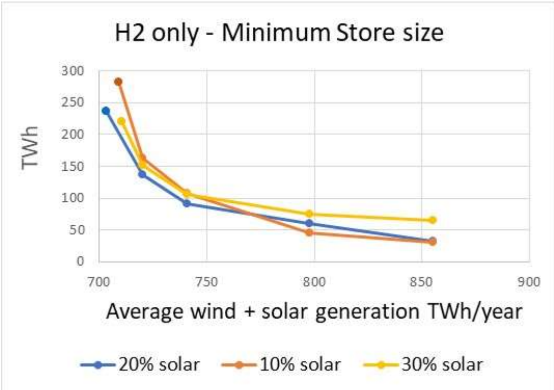

Figure SI 8.4 Minimum store size as a function of wind + solar generation for different solar/wind mixes

	Peak Surplus GW	
Solar/wind mix	741 TWh/year wind + solar	800 TWh/year wind + solar
10:90	155	172
20:80	181	201
30:70	210	232

Table SI 8.2 Peak surpluses at a given level of renewable generation for different solar/wind mixes

2. For a fixed average cost of wind plus solar generation, the cost of storage is (very slightly) higher at 10% and 30% solar than at 20%, as expected. However, allowing for the fact that solar energy is expected to be cheaper than wind, the 70:30 mix leads to the lowest average cost of electricity (by a very small margin) if the surplus has no value, but not otherwise. Nevertheless, 20% solar is used in this report because delivering 30% of the high level of wind plus solar that will be needed in 2050 would be very challenging. It turns out that the average cost of electricity is not very sensitive to the wind solar mix, which is reassuring as the mix will partly be determined by non-technical factors, such as planning permission, and the appetite of investors.

Baseload Nuclear

The effect of adding 50 TWh/year or 200 TWh/year of nuclear baseload to a wind/solar/hydrogen storage system was described in section 8.3.2 (with a 90% load factor, 50 and 200 TWh/year would require generating capacities of 6.3 and 25.4 GW respectively). Table SI 8.1 shows the effect this would have on the hydrogen storage system.

Baseload TWh/year	% of demand	Wind + solar at cost min TWh/year	Demand met from storage TWh/year	Electrolyser power GW	Storage Capacity TWh – without contingency	Average cost of power* with nuclear @ £78/MWh
0	0	760	82	77.7	79.6	60.1
50	8.8%	700	73	72.2	67.0	61.9
200	35%	500	52	46.3	58.3	67.6
AFRY model of 570 TWh/year demand. Wind + solar with H2 storage - central costs						
*without cost of transmission and grid services						

Table SI 8.3

Adding baseload reduces the level of wind and solar supply that is required (as already seen in Figure 23), and the size of the storage system. Adding 200 TWh/year of baseload (which meets 35% of demand) reduces the required electrolyser power by 40%. However, it only reduces the required storage capacity by 27% (which is less than might perhaps have been expected, because the load that has to be met by wind/solar and storage is more volatile with baseload than without).

If nuclear costs less and/or storage costs significantly more than assumed here, adding nuclear could lower the cost. If it turns out that the cost of electricity is similar with and without nuclear, then – given the importance of reaching net-zero as soon as possible - the question of how much nuclear to add would depend on the relative speed with which nuclear capacity and wind/solar/storage capacity can be built, and the value attributed to diversity of supply.

Nuclear co-generation

Nuclear power could be used to supply electricity to the grid when there is a need and, at other times, to produce hydrogen to be stored and used to generate electricity later. To understand the circumstances in which this would be cost-effective, assume that nuclear provides an average of 10 GW/87.6 TWh/year (which would require an installed capacity > 11 GW as the load factor will be $\leq$ 90%).

Advocates of co-generation argue that nuclear heat can be used to improve the efficiency of electrolysis, or at future high temperature reactors split water thermochemically to produce hydrogen. At Pressurised Water Reactors, the only type that is likely to be built in the UK in the foreseeable future, steam taken off at low pressure could be used to enable the use of increase the effiency of electrolysis, but withdrawing heat would reduce the efficiency of electricity generation.

In modelling co-generation, it was assumed that

- when there is a deficit (i.e. electricity demand > wind + solar): nuclear generated electricity covers as much as it can. Any remaining nuclear power is used to make hydrogen.
- when there is a surplus (i.e. demand < wind + solar): all nuclear is used to make hydrogen, except when the store is full.

Assuming first that 74% efficient electrolysers would be used, costing $450/kW in 2050, the base costs for hydrogen storage, and that wind plus solar cost £35/MWh, it was found that co-generation would only lower the average cost of electricity (relative to that found with hydrogen storage without nuclear) if the cost of nuclear electricity is less than £60.1/MWh. In this case the cost minimum occurs with wind plus solar generation of 654.4 TWh/year, broken down: 467.5 - used to meet demand directly + 123.6 - used to make hydrogen + 62.3 curtailed. The 87.6 TWh_e/year of nuclear generation breaks down: 41.9 uses to make 37.7 TWh_{LHV} of hydrogen + 34.5 - fed into the grid + 11.2 unused (in surplus but store full).

The IEA's analysis[2] implies that, taking account of the effect of extracting heat, nuclear generation of hydrogen by alkaline electrolysis would be 14% more efficient with, compared to without, the use of nuclear heat. This would increase the 2050 efficiency of 74% assumed in this report to 84.4%, leading to a breakeven slightly less than £60/MWh (again assuming that electrolysers cost $450/kW).

8.4 Multiple types of store

Combining ACAES with hydrogen storage

Figures 27 and Table 8 reported some results found when modelling a combination of ACAES and hydrogen storage. Figures SI 8.5 provide values at different points on the surface in Fig 27.

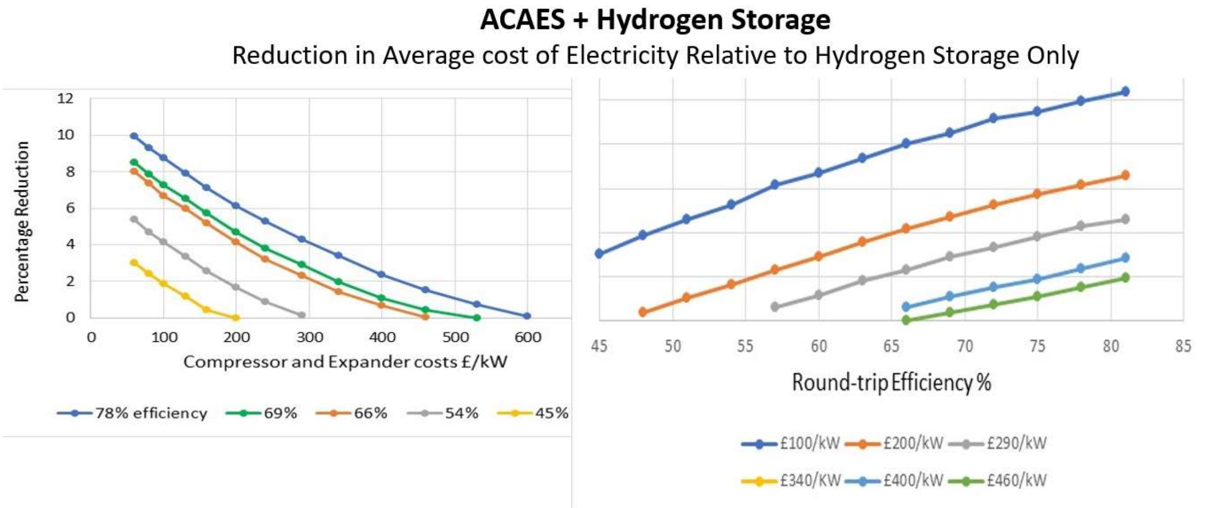

Fig SI 8.5 *Percentage reduction in the cost of electricity if ACAES is combined with hydrogen storage as a function of the cost compressors and expanders and the round-trip efficiency*

8.5 Use of Natural Gas with CCS

Methane Emissions

It has become conventional to use the 'Global Warming Potential' (GWP) to relate the climate impacts of methane and CO2. The Intergovernmental Panel on Climate Change (IPCC) has "indicated a GWP for methane between 84-87 when considering its impact over a 20-year timeframe (GWP20) and between 28-36 when considering its impact over a 100-year timeframe (GWP100). This means that one tonne of methane can considered to be equivalent to 28 to 36 tonnes of CO_2 if looking at its impact over 100 years".

However, GWP is based on comparing the effects of emitting single pulses of CO2 and methane. This report is concerned with the effect of switching on steady sources. A steady source of CO2 leads to a linear rise in temperature with time. Steady leakage of methane produces a temperature rise that is approximately 128 times that produced by steady emissions of an equal mass of CO2 at the end of the first 20 years after a source is switched on[3]. The factor of 128 drops to around 8 after 20 years, leading to a relative temperature rises caused by steady emissions of equal amounts methane and CO2 of 88 after 30 years and 32 after 100 years.

Given the urgency of limiting temperature rise, a 'CO2 equivalence' of 128 is used in this report, based on the effect of constant sources after 20 years.

When used in conjunction with wind and solar energy, gas + CCS will be used at a variable rate. However, the assumption that the average rate is the same in every year is a good enough basis for evaluating the climate impact.

Availability of Gas

UK gas consumption was 769 TWh_{LHV} in 2021 of which 327 TWh_{LHV} was provided by British gas fields, while the UK's proved gas reserves were 2000 TWh at the end of 2020[4]. It is expected that output from British gas fields will fall by some 15%/year, and that by 2030 80% of expected demand will be met by imports, unless significant investments are made[5], which seems unlikely as new fields will be increasingly marginal. Norway provides most of GB's imported gas, but the *marginal supply is from importing LNG which generates higher emissions*. Norway's proved reserves are seven times the UK's, but they will eventually be depleted.

With 47% HHV efficiency, 43 GWh_{LHV} of gas would be needed to provide the 20 GWe moddled below. UK gas consumption averaged 88 GWh_{LHV} in 2021 of which 33 GW_{LHV} were supplied by UK gas fields. *It might not be prudent to rely on a maximum rate of supply that is much larger than UK gas fields can provide*.

.

Flexibility of gas + CCS

According to the International Renewable Energy Agency[6] 'flexibility initiatives' could increase the ramp rate of CCGTs from the current average value of 2-4%/minute to 8-11%/minute, although they would not change the minimum up- and down- times, of 4 and 2 hours respectively. With effective control systems and management, it is not expected that the ramp rate would be compromised by adding CCS[7].

Forecasts of supply and demand could be used to allow gas + CCS to provide most of the flexibility needed to match the variability of wind and solar supply and demand, although assuming full flexibility, as done below, will lead to a balance between supply for storage and form gas + CCS that could not be achieved exactly in practice, i.e. it overestimates the use that can be made of gas, and underestimates the role of storage.

Cost of gas plus CCS

BEIS's central 2020 projection for the 2040 cost of electricity generated by gas with CCS is

£[(18.4 fixed cost)/(Load Factor) + 62 variable cost)/MWh

Gas contributes £47/MWh to the variable cost, assuming a fuel price of 64p/therm, while carbon dioxide emissions contribute £8/MWh, assuming a carbon price of £220/t CO_2, 47% HHV generation efficiency and 90% CO_2 capture. In the high/low projections, the fixed cost is 35% higher/lower.

BEIS give few details of how their assumed costs were calculated, but it appears (after allowing for differences in the assumption on, and treatment of, the cost of gas and the carbon price), that the capital costs are very close to those found by Wood consultancy[8]. Wood assume that the connections to the gas and electricity grids and the pipelines needed to dispose of CO2 are all 10km in length (running to different locations along separate corridors, without major obstructions). *In the case of CO2 disposal 10 km seems short if, as is expected, CO2 is stored in off-shore aquifers*. Wood find that (with a 90% load factor, and a 10 km pipe) transporting and storing CO2 contributes £7.9/MWh to the fixed cost.

BEIS's central fixed values is in line with EIA's $28.89/MWh for a plant commissioned in 2024[9], in so far as comparison is possible without details of the assumptions.

Using gas to provide the flexibility needed to complement wind plus solar

Natural gas generation equipped with CCS could in principle be used, rather than storage, to provide the flexibility needed to complement wind and solar. Fig SI 8.6 shows the average cost of electricity if this were done, assuming BEIS's projected 2040 costs for gas with CCS.

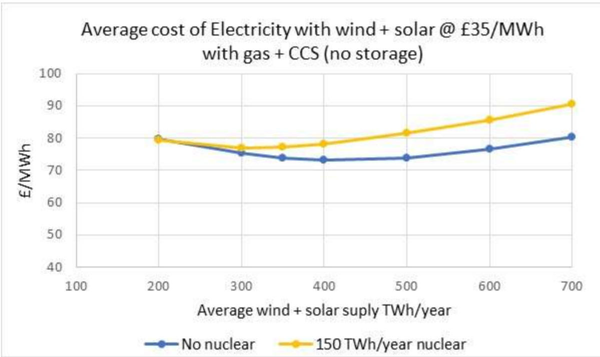

Figure SI 8.6. *Average cost of electricity provided to the grid if all flexibility is provided by natural gas generation equipped with CCS, without/with 150 TWh/year from nuclear (or other baseload) at £78/MWh. The cost (~ £1/MWh) of providing grid services is not included.*

The minimum cost without nuclear shown in Fig SI 8.6 is £74/MWh, compared to £63/MWh if all flexibility is provided by hydrogen storage (including the cost of transmission between wind and solar farms and storage, but without the cost of providing grid services in either case). If wind and solar supply costs £45/MWh, 74/MWh would increase to £81 while £63 would increase to £76 (as much more wind and solar is needed in the case without gas plus CCS). The difference depends strongly on the assumed cost of gas, and less strongly on the assumed price of carbon,

Using 20 GW_e of gas + CCS flexibly in combination with hydrogen storage

It will be assumed that the gas is only used when the hydrogen store is < X% full. The overall cost is minimised with X = 88%. More sophisticated ways of managing the use of gas, coupled with the use of forecasts of futures storage needs, could reduce the cost further. However, given that the reduction in going from 100% to 88% is only 1.5%, the effect would probably be small.

The result of adding 20 GWe of gas + CCS power to hydrogen storage, with X = 88%, are shown in the Table below with BEIS's central value of the fixed cost of gas + CCS, *assuming that to a good approximation it can be operated fully flexibly*. With the high/low costs the cost of power would be £0.65/MWh higher/lower.

Cost £/MWh Without transmission or batteries	**Base Storage costs + wind & solar @ £35/MWh Gas @ 65 p/therm CO_2 @ £220/tonne**	**With higher costs**		
		Wind +Solar @ £45	Storage costs x 2	W+ S @ £45 & storage x 2
No gas	59.2	72.5	71.7	85.1
20 GW gas	58.7	69.6	67.8	78.7
Difference of cost without/with gas + CCS (red – cost with gas is lower)**:**				
With costs above	- 0.5	- 2.9	- 3.9	- 6.3
With C tax x 2	+ 0.3	- 2.2	- 2.9	- 5.6
Gas @ 100 p	+ 4.0	+ 4.0	+ 0.8	- 1.9
C tax 2 and gas @ 100 p	+ 4.7	+ 4.7	+ 1.5	- 1.1
	With BEIS projected cost of gas + CCS			

Table SI 8.4

The differences are the net effect of much larger changes. For example, in the base case with 5% discount rate and wind and solar costing £35/MWh:

20 GWe of gas plus CCS contribute £11.54/MWh to the average cost of electricity (£5.66 from the fixed cost; £5.88 from the variable cost), but

this is offset by savings of £12.01/MWh from: decreased need for wind and solar (£8.60); lower electrolyser power (£1.26); smaller storage capacity (£1.27), 20 GWe less power needed from hydrogen (£0.88).

Possible use of blue hydrogen

According to a report prepared for BEIS[10], blue hydrogen will cost around £70/MWh_{LHV} to produce in 2050 with autothermal reformation of natural gas equipped with CCS, assuming that gas costs 95p/therm (with gas heating, the projected cost is slightly lower).

Use of power generated by blue hydrogen as baseload

With the assumptions on power generation from hydrogen made in this report (55% efficiency and a generating cost of about £3/MWhe with a 100% load factor), baseload power provided by hydrogen that cost £70/MWh would cost £130/MWhe, to which the cost of gas (at 95p/therm) contributes £75/MWh. Adding baseload at £130/MWhe to hydrogen storage would increase the averge cost of electricity. For it to lower the cost, the price of gas would have to be below 49p/therm even if storage costs are at the top of the range found in this report, wind plus solar power costs £45/MWh and the discount rate is 10%.

Continuous feed of blue hydrogen into the store, together with green hydrogen

Suppose that 20 GW_{LHV} of blue hydrogen were fed into the hydrogen store, whenever it is able to accommodate it, together with green hydrogen. Assuming that blue hydrogen costs £70/MWh_{LHV}, and using the base costs of hydrogen storage, a 5% discount rate, and a cost of £35/MWh solar plus wind power costing £35/MWh, it is found that the minimum cost of electricity is £67.8/MWh, with average wind plus solar supply of around 600 TWh/year. With the high cost of storage, 10% discount rate and wind plus solar power costing £45/MWh, the minimum – which is also reached at around 600 TWh/year – is £89.4. These costs are very sensitive to the price of the gas used to make blue hydrogen: if it were 64p/therm – rather than the assumed 95p/therm – the cost would drop by £7.0/MWh. This could make adding blue hydrogen financially attractive if gas prices stabilise below 95p/therm and the cost of electricity without blue hydrogen is in the top half of the range considered here.

8.6 Possible use and value of surpluses

It has been seen that the average cost of electricity in systems that rely on large-scale storage is sensitive to whether the residual surpluses, that remain after the demand that was modelled has been met, have any value. Additional possible demands that were not modelled, which could be met at the marginal - or in some cases the full - cost of generation, include:

- Making green hydrogen for purposes other than storing electricity. There is a potential demand for several 100 TWhs of hydrogen (see e.g. FES[11]), which - in a low carbon world - is likely to be used in the provision of industrial (and possibly space) heat, as a chemical reducing agent (e.g. in making iron), in transport (heavy goods vehicles, rail and possibly shipping and aviation), and in making ammonia (which has its own uses and could also fill some of the possible roles foreseen for hydrogen, e.g. in powering ships). Hunter et al[12] find that coproducing and selling hydrogen to other markets could reduce the cost of electricity delivered by hydrogen systems by up to 39% compared with scenarios without coproduction.

- Exporting it through interconnectors, was discussed in the report.

- Storing surplus energy as heat to be used to supply heat, e.g. by heating (or topping up) thermal stores connected to district heat networks, using low-cost resistive heating (since this use would be occasional, heat pumps would probably be more expensive).

- Meeting new needs that may arise that can make good use of spasmodic power, such drying biomass.

8.7 Contingencies against periods of low supply

As the role of electricity grows in heating, transport and industry, resilience of supply, transmission (which is discussed in Chapter 9) and distribution will become ever more important. The issue of the degree of reliability that should be ensured, which is ultimately a political question, is outside the scope of this report, which has focused on systems which can in principle meet 100% of demand.

It is argued in the report that contingency should be added to store sizes to ensure that the lights stay on in exceptional periods of low supply. 20% was added in the modelling described in Chapter 8, and it was found above that increasing this to 40% has only a modest effect on the average cost of electricity. Whether 20% or 40% is enough can only be determined by modelling based on weather data from periods with lower wind speeds than seen in the 37 years studied, allowing for possible changes due to climate change.

The alternatives to simply increasing store sizes are:

a) Demand management

The analysis described in section 8.7 shows that short-term demand management measures that are used to flatten and shift peak demand could not deal with the periods of exceptional low supply when, if they had not been made large enough, the stores would have become empty. However, as discussed in section 2.7 and SI 2.7, some countries have been able to reduce electricity use by up to 20% for periods of months. Making such large reductions may become more difficult as the role of electricity grows, but it is possible that 'pre-emptive' demand management when periods of low supply, such as those shown in Fig SI 2.5 A, B and C, are forecast could help reduce the possibility of stores becoming empty.

A necessary preliminary to studying pre-emptive demand management fully would be to construct a model with future demand adjusted to take account of the weather over the period in which historical weather data are used to analyse the need for storage (this was done while the report was being printed: see page 198). Meanwhile, the AFRY model of future demand used in this report, which is based on the weather in 2018, was used for every year in the period 1980-2016. This procedure underestimates demand in periods when temperatures were lower than in 2018, and overestimates it when they were higher.

An estimate of the potential of **pre-emptive demand management** can be obtained by using the AFRY model (which is for 2050, and takes account of increased electrification of heating, transport etc.), ignoring correlations and asking: what would the effect have been of pre-emptively reducing demand in all consecutive periods of three months in which wind supply is forecast to be below a given fraction of the average for those three months? Using the data on which the three-month outlooks published by the Met Office[13] are based it would be possible, using regressions, to construct a good proxy for the likelihood of given values of wind power, which is proportional to $\langle \text{wind speed}^3 \rangle$, over the coming three months, at heights that are typical for the hubs of wind turbines and wind speeds below the maximum at which they are shot down; further, if it seemed worthwhile, improved location dependent forecasts of this quantity could be obtained, which could be combined, weighted by where wind turbines are located and their characteristics (private communication from Philip Bett at the Met office).

The potential use of these use of such forecasts and can be moddled using Renewable.ninja data for 1980 -2016 and AFRY's model of 2050 demand in each year. First, the average value of available wind energy in the coming three months divided by the average for those three months was calculated, with the results shown in Fig SI 2.6 C. Second, the hydrogen only storage case was moddled, with the central values of storage and wind plus solar costs and average wind + solar generation of 741 TWh/year, for different levels of demand reduction in three-month periods in which wind plus solar generation is less than 80%, 85% and 90% of the average for those months. The effect on i) the averge cost of power, ii) the electrolyser power and iii) the size of the store is shown in the Fig SI 8.6.

It is seen that, according to this modelling, the size of the store could be reduced by

- 10% by reducing demand by 2.5% in the 19 months that form parts of sequences of $\geq$ three months in which wind supply is less than 80% of the average (there are 26 such months in the 37 years studied), or 1 % when it is less than 90% (there are 152 such months). There is very little difference between the 85% and 90% cases because the required storage capacity is determined by the drop in the level of hydrogen in the store in the period February 2009 to May 2011, and the number of months in which is assumed that demand is cut during this period only increases from 14 in the 85% case to 15 in the 90% case, as can be seen in Fig SI 2.6 C.
- 20% by reducing demand by 4.5% in the 19 months that form parts of sequences of $\geq$ three months in which wind supply is less than 80% of the average, or 1.5% when it is less than 90%.

The necessary electrolyser power is not so sensitive to the reduction in demand. The reduction in the average cost of electricity, which would be offset by any costs incurred in reducing demand, is insensitive because it is dominated by the cost of wind and solar supply.

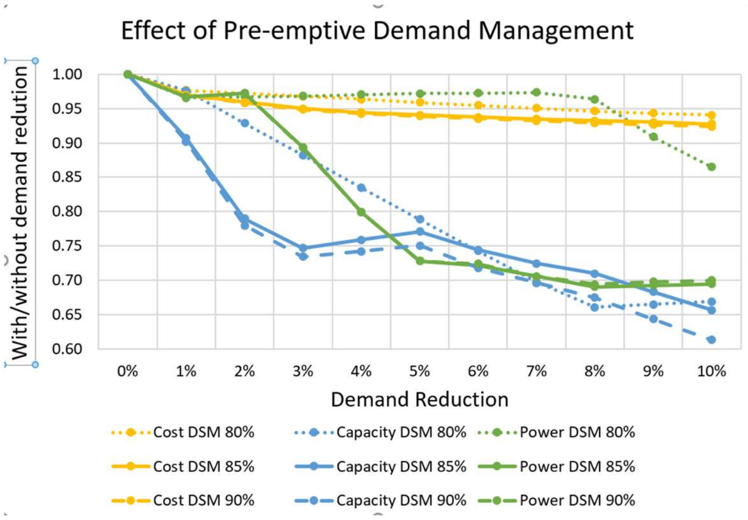

Fig SI 8.6. Reductions in the average cost of electricity, the required storage capacity and electrolyser power that (according to the Ninja.remewables and AFRY models of wind and solar supply) would be produced by reducing demand by different levels in three-month period in which wind supply is less than 80 %, 85% or 90% of the average.

In conclusion this modelling shows clearly that significant reductions in the required storage capacity could be made by reducing demand by quite modest amounts, which could be done using the methods disused in Section 2.7 of the Report and SI 2.7. *This is important because,* as well as reducing the cost*, the less storage capacity is needed, the easier it will be to provide it by 2050*. It would be interesting to refine the crude modelling used here by, for example studying the effect of only reducing demand when the level in the store is less than a given value; looking at periods of (say) two or four months rather than three; choosing which type of demand to reduce (this can be done in the AFRY model); assuming that the level of reduction is different at different times of day and perhaps in the week and at weekends; and including the effects of short-term demand management in the AFRY model after including correlations between the weather and demand (which would not be expected to change the qualitative that occasional modest pre-emptive reductions in demand would lead to significant reductions in the need for storage).

b) Adding other sources of supply

Modelling is needed to understand the need for contingency if some flexible gas generation (equipped with CCS) is assumed to be available, which would (as discussed above) reduce the need for storage.

Some other possible additional sources are listed in Table SI 8.3. In most cases, large scale infrastructure would have to be kept available for rare use, which would be very expensive, as would importing hydrogen as hydrogen, which (like importing ammonia) would depend on the availability of totally dependable sources of supply that would only be called on very occasionally.

Possible sources of energy for very occasional use in exceptional periods of low wind and solar supply	Requirements
North Sea gas plus 4-stroke engines or solid oxide fuel cells already in place for use with hydrogen (ignoring the small amount of CO_2 this would produce)	Keep gas fields and supply lines open
Imported ammonia for use in power generation	Large NH3 storage tanks
Imported ammonia used to make hydrogen	Ammonia to hydrogen conversion facilities
7 made from iron and water (as discussed in Chapter 7 and SI7)	Necessary infrastructure
Hydrogen imported as hydrogen, which would be very expensive	

Table SI 8.5 Possible additional energy sources

The possible occurrence of clustered period of low supply, and ways of dealing with them, deserve more study in different scenarios. In addition to adding some flexible gas generation, some combination of other measures could reduce the need for large contingency in the size of stores, e.g. demand management, temporarily reducing any other large scale uses of green hydrogen, importing relatively small amounts of ammonia and converting it to hydrogen when periods of low supply are forecast at a rate that did not require very large-scale facilities, and more generally using long-term forecasts in scheduling the use of storage, as suggested in section Chapter 3.

8.8 Different levels of demand

In Section 8.8 crude modifications of the AFRY model of 570 TWh/year of demand were described, in which demnd is equal to 400 TWh/year and 700 TWh/year, and the profiles are very different. To ease comparions of the cost of electricity in the three cases, it is plotted in Figure SI 8.6 relative to the thresholds at which all demand can be met by wind & solar supported by hydrogen store (which are 542.5, 703.5, and 865.0 TWh/year wind + solar supply for demands of 440, 570 and 770 TWh/year respectively).

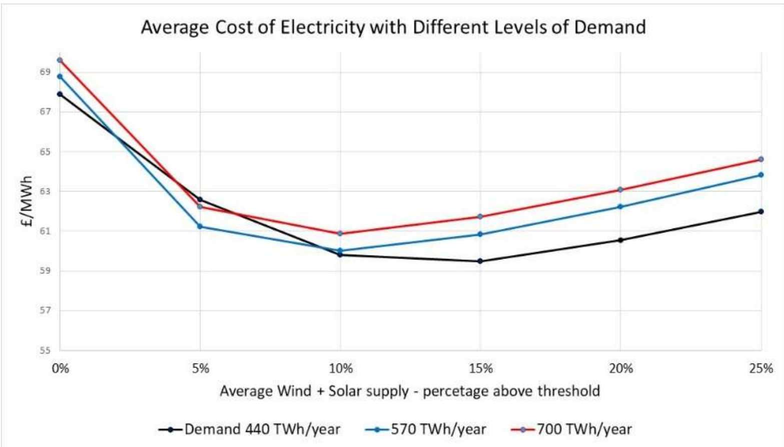

Fig SI 8.7 Averge cost of electricity with three deferent levels and profiles of demand, assuming a fixed wind/solar mixture of 80/20, that wind + solar costs £35/MWh and a 5% discount.

8.9 Other studies of the cost of storage in GB

The studies made by AFRY are analysed in Annex 2 of SI 3. This section contains more details of studies that were referred to in section 8.9 and SI 3.2 by Price et al's[14], Cardenás et al[15] (C below and Cosgrove and Roulstone[16] (CR below). Price et al's, who studied UK electricity in the context of a (partly connected) European energy system, found 2050 UK storage volumes and costs that are similar to those found in this report, and - as found here - that including nuclear in the future generation mix would increase the cost of electricity, unless its cost is well below current expectations. C and CR, whose paper is reproduced as an Annex to SI 8, treat the UK as an energy island, as done in this report for reasons discussed in Chapter 2. Nevertheless, comparisons are not straightforward because

1. **Different assumptions were made about** –
    - Capital costs: C used estimates of current costs; CR presented results based on estimates of both current and future costs.
    - Systems lifetimes and the discount rate: assumptions on lifetimes were similar. Discount rate: CR - 7%; C - 0%; this report – 5% and 10%
    - O & M costs: CR - 2% (fixed); C - 0; this report – various Table 8.2 and 8.3).
    - Electricity demand: C&G used actual demand in recent years; R used a model of future demand which peaks at 166 GW, leading to large generating costs. The AFRY model of 2050 demand, which peaks at 98 GW, is used in this report.
    - Wind and solar supply: C only studied seven years of weather data, which they recognise is likely to underestimate the need for storage; R used the Ninja Renewables model (based on weather data for 1980-2016) which is used in this report, where 20% contingency is added to the size of the hydrogen store to allow for vagaries of the weather not seen in the 37 years studied, and the possible effects of climate change.
    - Costs of wind plus solar for the mixes considered: CR - £34/MWh; C - £43.2/MWh; this report £30.2, £35 and £45/MWh.
2. **Differences of methodology affect the costs that were found**:
    - C assumed perfect foresight, and the electricity costs they found are therefore lower bounds on what would be found with a scheduling procedure that could be used in practice, with their other assumptions fixed. Foresight was not assumed in the procedures used by CR and in this report, whose results are therefore less than the ideal (but could not necessarily be obtained in practice given the degree of coordination required to implement these procedures).
    - CR adjusted power and store sizes with an eye on costs, but did not minimise the system cost systematically.
    - The costs in this Report include estimates of the cost of providing grid services and of transmitting electricity from wind and solar farms to stores the cost, albeit by under £1/MWh.

Common points - despite these differences in assumptions and methodology, these studies

- All agree that a net-zero GB will need many tens of TWh of storage in 2050.
- Find average costs of electricity that are not dissimilar. This is because the cost of wind and solar power (used directly plus stored plus curtailed) makes the largest contribution. The average cost is higher (by 70% or more) than the cost of the input wind plus solar power.

C found that combining hydrogen storage and ACAES leads to lower overall costs than using either alone, and that adding batteries puts up the cost, as found in this report. CR, who modelled hydrogen, ACAES and batteries together (but not separately), found that including baseload supply puts up the cost, unless its cost is close to or below BEIS's low projection for nuclear costs, as also found in this report.

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Annex

UK Multi-year Renewable Energy Systems with Storage - Cost Investigation T Roulstone and P Cosgrove

Reliable Renewable Energy Systems

The falling cost of renewable sources of energy together with more stringent restrictions on greenhouse gases are leading towards energy systems that are dependent on inherently variable solar and wind generation. In the future, energy storage will be required to support the reliability of the energy system – its ability to always meet demand.

Storage costs cannot be viewed in isolation but should be seen in light of the alternatives and their role in complementing intermittent renewables. Early US studies[1] recognise system energy costs must include both renewable costs and the storage costs that make the system reliable. This preliminary costs study for the UK uses multi-year energy storage studies and seeks to provide an understanding of the factors that drive renewable whole energy system costs.

As has been shown[2] for the UK, renewable energy systems are inherently intermittent due to their dependence on the daily cycle of solar power and random patterns of weather that drive wind power. Such energy systems need both overcapacity and energy storage to ensure that supply always meets demand. The costs of these additional systems could be significant.

The questions to be answered include:

1. What are the key drivers of cost for such combined systems?
2. How much additional capital expenditure will be required?
3. How will these sums affect the cost of energy?

We can say for the calculation of both capital costs and for energy costs of renewables, the total or Blended Energy Costs are those required to provide a renewable supply that meets demand:

Blended Energy Cost = Cost of renewable energy supply to meet demand
+ Cost of overcapacity + Cost of storage + Grid enhancements - not covered here

Grid enhancement costs for net-zero will be significant. They can be divided into three categories: transporting the higher energy demand; accommodating the higher power associated with renewables and their inherent variability; transporting the renewable energy to and from storage that will not necessarily be close the centres of supply or demand. These are not included here but are estimated by OECD[3] to be about an additional $13/MWh for 75% renewables.

Renewable costs

Renewable energy costs are falling and this trend is expected to continue with the new forecast of future energy costs by IEA[4] for renewables in Western Europe in 2040 being well below current levels.

[1] Ziegler & Trancik (2019)
[2] Cosgrove (2021)
[3] OECD (2019)
[4] WEO (2020)

There are three main factors at play in these reductions. First, the capital costs are being reduced by better technology and, in the case of wind, by larger turbines. Second, the capacity factors are improving, some quite markedly, with the best offshore wind capacity factor being quoted as high as 59%. Third, the cost of finance for these investments has reduced as they are now seen as low risk and provide dependable revenue for large investors.

Weather data for this analysis[5] [6]used capacity factors that are representative of the wind and solar farms that are being and planned to be built and also the progress of technology. These supply capacity factors are lower than some forecasts but are retained for consistency with the weather and storage modelling analysis.

Previous work[7] has shown a renewable mix of 20% solar and 80% wind to be close to being optimal. Onshore and offshore wind are assumed to be 30% and 70% of the wind supply respectively, as seems likely for the UK in 2050. This mix of renewables is retained throughout this preliminary cost analysis.

Table 1. Renewable energy specific capital costs from WEO 2020

Renewable Energy	Specific Capital per kWe	LCOE per MWh
Solar	$440	$30
Onshore	$1,380	$45
Offshore	$1,820	$35

Energy costs (see Table 1 above - data from WEO (2020)[3]), are factored to take account of these capacity factor differences and these result in a blended renewable energy cost of $47/MWh for 2040, which is similar to that from BEIS (2020)[8].

Storage costs

There are two elements of storage capital cost to consider:

- Power-related costs – the cost of conversion systems at the input to and output from the storage element. For the purposes of this preliminary analysis it is assumed that the power requirement is the same for input as output but, in principle, these may be different depending on how storage power supplies are scheduled.
- Volume related costs – the cost of storing the energy which is dependent on the means of storage. For example, this could be batteries, compressed air, liquid air, or chemical stores in underground caverns.

Energy storage system costs not well defined because few have bene built and therefore are subject to large uncertainties.

Battery costs, (Li-ion) are better understood[9] [10]. Unit costs are falling with the potential for battery costs to fall by another factor of two (NREL) or three (Aurora) by 2040.

Only two CAES (Compressed Air Storage) projects have been built, hence their unit costs are much less certain. To achieve high levels of efficiency (70% or greater) they need to be adiabatic with thermal transfer between the incoming compressed gas and the expanding outgoing gas (Advanced Adiabatic CAES) for which no specific costs are available. CAES

[5] Renewables.ninja
[6] Staffel & Pfenninger (2016)
[7] Cosgrove (2021)
[8] BEIS (2020)
[9] NREL (2021)
[10] Aurora (2016)

uses large leak-proof caverns for storage. The cost of these caverns dominates CAES system costs. These cavern costs are reviewed by Locatelli[11] who shows that they can vary by at least a factor of 10 and perhaps by a factor of 100. This wide range is confirmed by the IRENA storage cost data[12]. More recent studies[13] give more defined CAES costs but still with very large uncertainties especially for volume related costs.
The study of energy storage using hydrogen is at an early stage. The system includes three essential elements:

1. Hydrogen production which for a net-zero carbon target is assumed to be produced by electrolysis, using renewables or other zero carbon energy;
2. Hydrogen storage, either on the surface which is expensive or in salt-caverns where they are available, as is the case in the UK;
3. Re-conversion to electricity using either gas turbines or fuel cells.

Volumetric unit costs are presented in terms of stored energy (LHV for hydrogen) rather than the electrical output to the energy system. Volumetric unit costs are presented in terms of stored energy (LHV for hydrogen) rather than the electrical output to the energy system. Figures for volume and power storage costs given below in Table 2. Estimate are in some cases current costs and other cases for twenty years hence.

Because of the emerging importance of hydrogen, cost reduction and efficiency improvement are being studied with opportunities in electrolyser stacks for hydrogen production and in power conversion using either hydrogen turbine (or perhaps reciprocating engines), or using fuel cells.

Hydrogen electrolysers have the potential to achieve stack costs of $400-500/kWe[14]. Reconversion costs are[15] $425/kW for fuel cells for PEM), with 60% efficiency available today, using high purity hydrogen. Gas turbines suitable for burning hydrogen cost $713/kW for open cycle (34% efficient) and $1,084/kW for combined cycle turbines (54% efficiency).

US studies[16] show hydrogen power costs are falling from $3000/kWe to $1300/kWe. UK studies indicate the potential for reductions of electrolyser stacks (to $400-500/kWe[17] [18]) and from the use of advanced fuel cells for power conversion ($425/kWe[19]). When adding the systems and compression units, combined specific power capital cost for hydrogen could in the future be as low as $1300/kWe.

Hydrogen can be stored above ground at high pressure, either as a very cold liquid, or underground at 100-270 bar pressure, either in salt caverns or in porous rocks. Salt caverns have been used for storing hydrogen both in US and UK at Moss Bluff, Spindle Top, Teesside and Clemens. Two are old, but Moss Bluff and Spindle Top are more recent. Volumes are up to 900,000 m3 and pressures up to 200 bar able to store 8,000 tone of hydrogen. Other figures in the literature are based on studies, extrapolation and scaling – include in Table 2 below.

For the cases where there are both cost and volume information, the data is plotted in Figure 1 below. Volume storage cost estimates for hydrogen are very varied. Costs depend strongly

[11] Locatelli (2105)
[12] IRENA 1.0
[13] Guerra (2020)
[14] Element Energy
[15] Ibid
[16] Guerra (2020)
[17] Element Energy (2020)
[18] ICCT (2020)
[19] RS Energy Storage (2020)

on the size of the cavern and the storage pressure. Ahluwalia[20] and H21[21] results are consistently lower than the others except at very high volumes/masses 3-4 million cubic metres and 30-40,000 tone of usable hydrogen. The ETI study[22] for the UK gives a typical large cavern size as 300,000 m^3 with the largest being 600,000 m^3, therefore the focus is around storing 1-3,000 tons of hydrogen- depending on cavern pressure. At this cavern size, costs are between \$0.6-\$2.0/kWh.

Shared surface facilities will reduce the cost when using multiple caverns. It is hard to analyse these costs are the studies are not similar and they are not fully detailed. The large differences in the costs of constructing the cavern and the project add-on costs are relevant. The very low £11m per cavern in the H21[16] study is at variance both with the ETI study[17] - £33m, the HyUnder[23] study - €28m (with a range of €25-50m) and GIE[24] - €81m for a larger 500,000m3 cavern. Also, none of the other studies given below have cavern construction costs as low at H21.

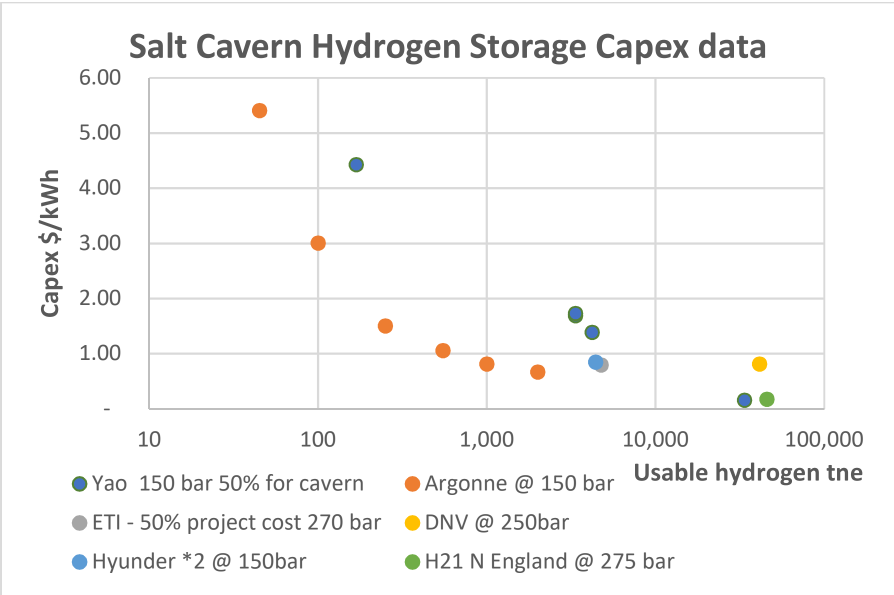

Figure 1. Hydrogen storage volume capital costs versus usable stored volume

A hydrogen storage volume capital cost rate below \$0.8/kWh might be achievable in 2050, with a very large cavern - 4 million m^3 (much larger than exists in UK), or multiple caverns served by shared facilities and very high pressure >250 bar. Nevertheless, the range of volume cost is wide and for the size of caverns in UK that can store 1-3,000 tone of hydrogen the most likely future specific capital cost for 270 bar storage is \$0.8/kWh. Near term projects costs could be higher.

Table 2. Selected energy storage technology cost studies

Type	Capex Power	Capex Volume	Efficiency	Source
Li-Ion Battery	$180-200/kW	$100-200/kWh	85%	NREL (2021)[25]
	$50/kW	$224/kWh	95%	IRENA Cost of
Service 2030				
	$400-1400/kWincl.			Aurora (2016)
	$871/kW	$39/kWh	44%	Schmidt (2019)

[20] Ahluwalia (2019)
[21] H21 (2018)
[22] ETI (2017)
[23] HyUnder (2013)
[24] GIE (2021)
[25] NREL (2021)

Compressed Air (CAES) $130-188/kWh 70% Lazard
LCOS 2.0
$420-700/kW $5-65/kWh 75% Locatelli (2015)
$300-700/kW $2-44/kWh 68% IRENA Cost of Service
2030
$900/kW incl. Aurora (2016)
$755-817/kW $31-35/kWh 60% NREL - Guerra (2020)
$2-140/kWh Dooner (2020)
$871/kW $39/kWh 44% Schmidt (2019)
$3/kWh from studies $1-100/kWh PNNL (2013)

H2 System Storage $0.15-1.5/kWh 42% Yao (2019)
$1500-2000/kW $0.8-2.4/kWh 35% ETI (2017)
$1300-3000/kW $1.0-3.7/kWh 42% NREL - Guerra
(2020)
$5000/kW $37/kWh 40% Schmidt (2019)
$1/kWh GIE (2021)
$0.3-0.8/kWh HyUnder (2013)
$1700/kW $0.8/kWh (40k tne) 40% DNV (2019)
$0.6-6.0/kWh Ahluwalia (2019)
$2175-3612/kW $0.17/kWh 35% H21 (2018)

Based on this data, we identify two illustrative cases:

1. Near term (2025) cost;
2. Future (2050) low costs.

Storage costs used in this study are based on:

- Li-Ion NREL (2021) which is both a recent and a broad ranging study.
- CAES a range of sources for current and future values.
- Hydrogen power costs are based on H21 data (current) and Guerra (future) volume costs are based on ETI (future) and Guerra (current).

Storage capital costs data is given below and operating costs are taken to be 2% pa.

Table 3. Energy storage technology costs

Current Storage Cost Rates	**Capex**	**Li-Ion**	**CAES**	**H2**
Power	per kWe	$ 200	$ 800	$ 2,175
Volume	per kWh	$ 200	$ 30	$ 3.7
Future Storage Costs	**Capex**	**Li-Ion**	**CAES**	**H2**
Power	per kWe	$ 180	$ 400	$ 1,300
Volume	per kWh	$ 100	$ 9	$ 0.8

Both renewables and storage have high capital costs and operating costs are low - a few percent of capital cost per year. The other main ‘operating cost’ of such systems are the losses incurred in storing and delivering energy from storage – the round-trip efficiency. These losses affect system cost through the extra renewables supplies required to make up for losses and balance the system

We can see that these storage technologies have very different economic characteristics. Li-Ion batteries have high volume costs and high efficiency, whereas hydrogen storage has much lower – 100 times – energy volume storage costs and lower round trio efficiency ~40$. CAES volume and power costs lie between these two extremes. These different economic characteristics mean that batteries are useful for short-term storage where volumes are relatively low, but much too expensive for large long-term storage. Conversely, hydrogen would be preferred where the emphasis is on much larger volumes of storage for the longer-term.

Energy storage needs

UK energy storage needs[26] for a three store system (Short - less than one day, Medium - one week and Long - longer periods including seasonal and year-to-year) were analysed using a storage modelling algorithm for 37 years of weather data and a typical annual demand profile. These needs have been shown to be large. The total size of storage can be reduced by the addition of further renewable capacity (overcapacity), by the provision of zero-carbon baseload, by demand side response measures and by interconnectors – Figure 2 below.

Overcapacity here means the extra supply in excess of that required to match demand. This can be used either to compensate for intermittency or to provide for the inherent losses in energy storage.

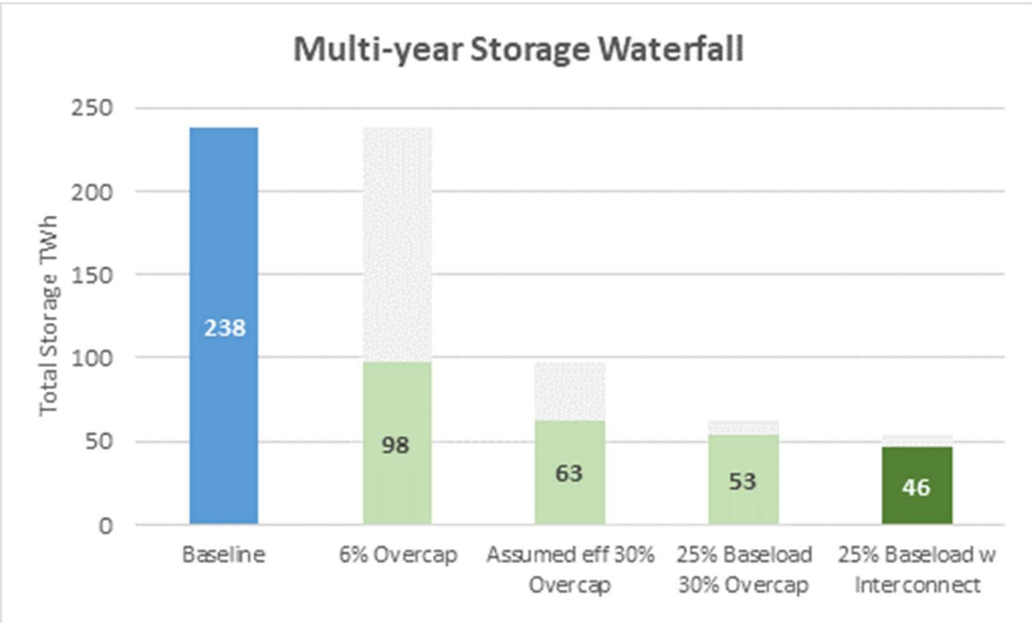

Figure 2. 2050 UK Energy System – 37 years 1980-2016 of weather – Reducing storage needs – from Cosgrove & Roulstone (2021)

In these studies, the aim was to reduce the total size of storage and the main effect was seen in the Long store that represents more than 80% of the total storage volume. We shall examine the effect of increasing overcapacity and storage cost rates on the cost of providing reliable supplies.

This method of storage scheduling maximises the efficiency of storage, but because stores work in sequence, except in very narrow and limited circumstances, high powers are required of each type of store. This is important because, during long wind droughts, the shorter stores could empty, leaving the Long store to provide the whole of demand. In this case the power requirement for the Long store would equal residual demand. In the simulation it was found that all stores require high powers capability – 80-140 GW - for a fully renewable supply system. Demand side response measures appear to be capable of

[26] Cosgrove (2021)

reducing these power needs, but by about 20 GW. The cost of these high power requirements for all types of store is significant.

While this scheduling method has the lowest losses, it is unlikely to be economic. An improved method of scheduling stores has been proposed by Zachary[27]. It optimises storage scheduling and avoids the high power requirements for all type of store inherent in the Cosgrove study while remaining efficient. It uses two scheduling techniques:

1. Using the most efficient store first, as above.
2. Matching discharge times across stores.

An optimising algorithm, derived from dynamic programming theory, finds at any time what is in effect the most effective compromise between the above two criteria, according to the current state of the stores and with the objective of minimising total unserved energy over time. Using this method the charging and discharging power of different stores can be managed more effectively while retaining storage efficiency.

Using the same data and energy system as Cosgrove, (600 TWh of demand) early results are promising. Store charging and discharging powers can be reduced. For a 100% renewable supply system and 30% overcapacity, the total store power required is only 5% above the peak residual demand. Store volumes (expressed in storage units) and powers are:

Volume:	Short-term 100 GWh	Medium term 4.8 TWh	Long-term 66 TWh
Power:	20 GW	60 GW	60 GW

The total storage volume is increased by about 20% and the mean unserved energy is restricted to a very low value of 1.6 GWh per year (60 GWh over 37 years), which is better than current UK Grid requirements, expressed as unserved energy. The peak unserved energy is 14 GWh – 15 minutes of mean demand but it would affect the whole power grid. This event could probably be forecast and therefore managed by extraordinary demand reduction. These results can be further optimised to reduce system costs. More work is required to integrate the method with the economics of storage.

Cost sensitivity studies

These cost studies make use of the storage size results from the multi-year storage analysis by Cosgrove[28]. Store sizes for several cases of overcapacity and baseload were examined. This analysis identified the smallest Long store size for given Short and Medium store sizes, as well as fixed amounts of overcapacity or baseload. However, the analysis did not directly optimise the other store sizes to minimise system costs. One of the more significant omissions is that it did not investigate the trade-off between the Medium and Long stores – as the Medium store is increased, it will partially displace the Long store in terms of delivering energy to the grid.

Medium store size sensitivity

More recent modelling of the variation of Medium store versus Long store size shows that much smaller Medium store sizes (see Figures 3 & 4 below) can still provide a reliable renewable supply with a modest increase in Long store sizes. This is because the Long store size is determined by long periods of low wind which the Medium store is incapable of dealing with. The Short store size is unaffected by this issue.

Because of the high cost of ACAES/Medium store power capacity these larger Long store results provide lower costs and therefore will be used. It was found that much below 20%

[27] Zachary (2021)
[28] Cosgrove (2020)

renewable overcapacity meeting demand could not always be guaranteed. Here we employ a range of 20%-40% overcapacity. Baseload supply reduces the storage sizes and hence the costs. Two cases with different baseload components are considered:

1. 100% renewable supply i.e. no baseload.

2. 30% baseload supply that reduces the size of the very large Long store and the supply required to meet demand from the Medium and Long stores.

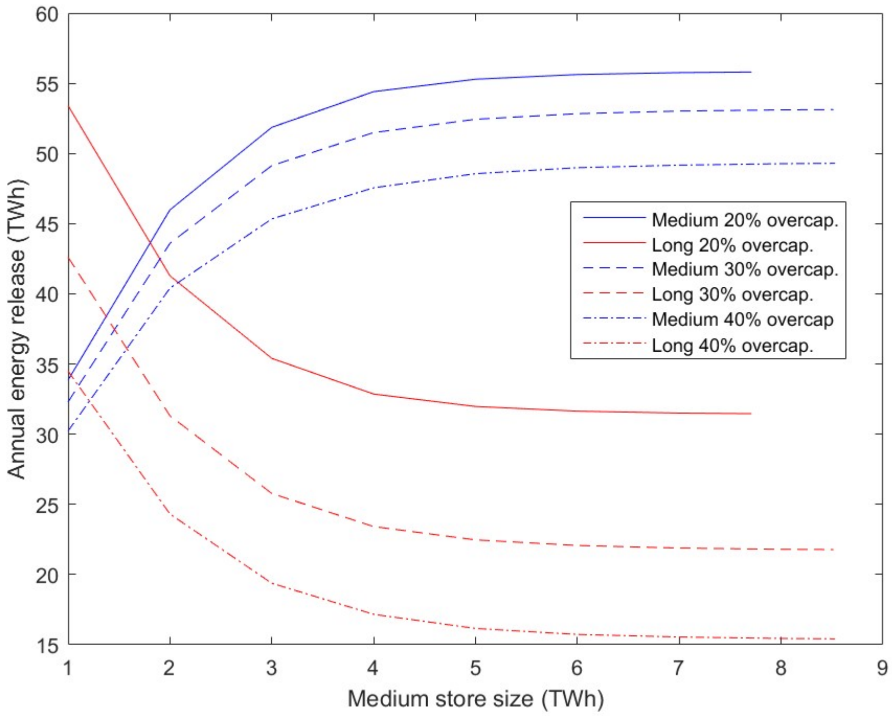

Figure 3. Energy release from Medium & Long stores versus Medium store size for 100% Renewable supply

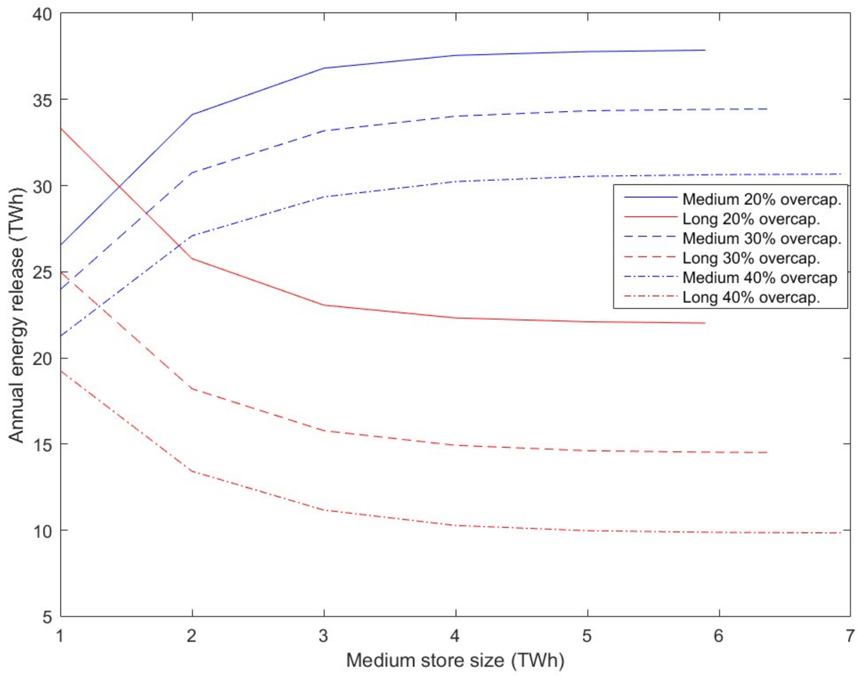

Figure 4. Energy release from Medium & Long stores for different sizes of Medium store for 70% Renewable supply

Based on this data, Medium store sizes alter the energy release from the other stores by 10% or less. These sizes are the lowest that preserve the role of the Medium store in covering the mid-term residual power fluctuations, and providing the largest contribution to meeting demand. Store sizes for these cases are:

Table 4. Required store sizes versus renewable overcapacity for no and 30% baseload

Storage Volume Data – TWh				
0% Baseload	**Overcapacity**	**Short**	**Medium**	**Long**
	20%	0.24	2.8	97.7
	30%	0.23	2.8	55.3
	40%	0.25	2.8	46.9
30% Baseload	**Overcapacity**			
	20%	0.20	2.0	53.0
	30%	0.19	2.0	43.5
	40%	0.21	2.0	35.4

Renewable power requirements

The capital costs of renewable energy systems for 2050 are high because of the large nominal power capacity required to deliver 600 TWh of supply to meet demand (and proportionately less for 30% baseload supply) with the inherently low availabilities of these systems – see Table 2. Both of these scenarios represent a massive expansion of solar and wind resources with increases of between 4 and 6 times currently installed wind and solar capacity.

A fully renewables system for 2050 provides 600 TWh of supply[29] with 20% solar and 80% wind (split 30/70% onshore/offshore wind), and 70% renewables provides 420 TWh of supply with similar characteristics. Renewable generating capacities for these two cases are given in Table 5 below.

Table 5. Renewable power capacity for 100% & 70% renewable supply to meet 600 TWh demand compared with current installed renewable capacities.

Nominal Capacity	Current	100% Renewables	70% Renewables
Solar	13 GW	125 GW	87 GW
Onshore Wind	14 GW	49 GW	34 GW
Offshore Wind	10 GW	98 GW	68 GW
Total	**37 GW**	**271 GW**	**190 GW**

Whole system capital costs

Using IEA forecasts of the renewables specific capital costs for 2040, and store volume and power capacity values we can estimate whole system capital costs. It assumes that the current renewables are also replaced during the period up to 2050. For renewable energy systems that ensure supply always meets demand, the costs of overcapacity and storage are added to the capital cost estimate of the system. For cases where renewables supply is less than 100% of 600TWh per year, another form of zero-carbon supply is required. The choice is between an advanced form of CCGT with CCS that is able to capture 99% of

[29] Cosgrove & Roulstone (2021)

emissions, bio-energy with carbon capture (BECCS), or nuclear power. The capital costs of CCGT with CCS and BECCS are not widely researched. A recent study by the Wood Group for BEIS[30] gives specific costs (converted to $ at PPP) which can be compared with those for nuclear given in the CCC Net-zero report[31].

Table 6. Specific capital and energy costs for selected zero/low carbon energy supply technologies.

Technology	Specific Capital Cost	Energy Cost
CCGT with post combustion CCS	$1,377/kWe	$139/MWh
CCGT with pre-combustion CCS	$2,135/kWe	$129/MWh
Oxy-combustion gas (Allam cycle)	$1,966/kWe	$111/MWh
BECCS	$4,377/kWe	$219/MWh
Nuclear Current (Mean)	$6,032/kWe	$136/MWh
Nuclear Future	$5,295/kWe	$99/MWh

Pre-combustion power systems such as the Allam cycle appear more likely to be able to meet the stringent carbon capture targets – but only when this has been successful demonstrated. Because of this technological uncertainty, the Allam cycle cost estimates have wider bounds of uncertainty than the other estimates. This estimate will be used for the CCGT-CCS case. However, for net-zero, all gas powered technologies depend on being able to successfully deal with the upstream emissions of methane that would negate the benefits of improved carbon capture from the generating power plant. BECCS capital and energy costs are higher. Current nuclear costs are based on a first-of-a-kind (in the UK) EPR. Costs could be reduced by different financing arrangements and by adopting a programme of series build. The future nuclear energy cost forecast is similar to the 2040 forecasts of other energy technologies.

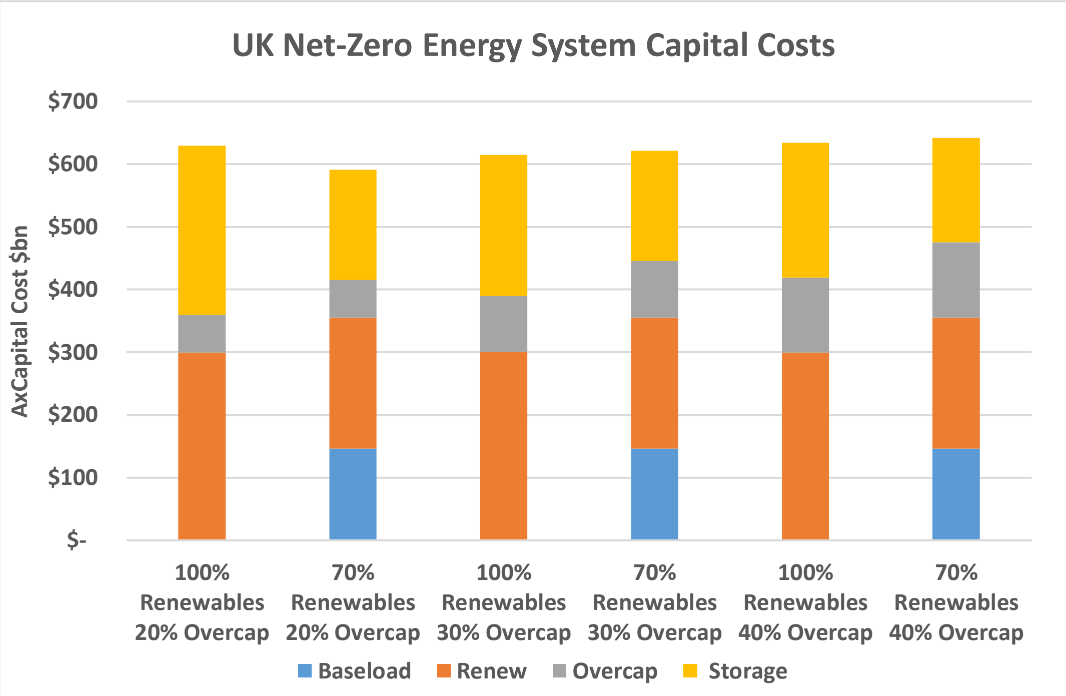

Figure 5. 2050 UK Energy System capital costs v overcapacity for 100% & 70% renewable share – future storage costs and sharing of power between stores.

[30] Wood (2018)
[31] CCC (2019)

Total capital costs for both a wholly renewable system and 30% baseload share system - for 2050 levels of demand. In Figure 5, capital investment requirements are presented for three levels of 20/30/40% overcapacity. Capital costs broken down in their elements: renewable supply; renewable overcapacity; storage and where applicable baseload.

Renewable supplies for 600 TWh demand cost about $300bn. To ensure that the system is reliable a combination of overcapacity and storage costs a further ~$300bn, increasing capital cost totals to about $600bn. The lowest cost wholly renewable system is that with 30% overcapacity - capital costs of the three storage technologies are:

Short (Li-Ion) $14bn; Medium (CAES) $67bn; Long (Hydrogen) $144bn.

Capital costs of storage are very dependent on future cost reductions and the ability to schedule power to share the power demand. Current storage cost for 30% overcapacity is much higher: $591bn versus $225bn. This difference becomes more extreme for 20% overcapacity where large store volume and power are required together. In general, scheduling the stores to share the power saves $100m of capital.

For the 70% renewable cases, total capital costs are very similar ~$600bn for the range of overcapacity considered. Lower costs of less overcapacity are to a degree offset by the higher costs of the larger long-term stores - capital costs are lowest for 20% overcapacity. Renewable supplies plus storage costs are reduced to $446bn. Baseload capital costs (based on future nuclear costs) add a further $146bn – for 20% overcapacity, the total system capital costs are $592bn.

Storage costs are similar in size, with the power related element increasing with overcapacity. If power sharing is not possible, capital costs increase by $100bn and are then the largest element of storage cost – dominated by the long-duration store power costs.

Storage costs have both a large range and have high uncertainties. Few energy storage projects other than Li-Ion battery, have been built to provide baselines for costs. The much lower storage costs that are expected in the future depend on production learning for equipment and the use of larger caverns for both compressed air and hydrogen storage. Technology cost is a crucial issue. The predicted lower costs are based on parametric studies rather than completed projects and importantly are not well defined.

Blended system energy costs

Energy costs for the renewable system that includes supply and storage can be expressed as the Blended or Levelized Costs of Shaped Energy (LCOSE)[32]. These blended energy costs are shown in Figures 6 below for a fully renewable system and Figure 7 for a system with 30% baseload.

New energy technologies are often evaluated at 10% discount rate. Long term infrastructure investments such as wind and solar have reduced their commercial risks so that they can attract funding at costs of 5% or less. Here storage energy costs have been calculated at a 7% discount rate, which is mid-way between current and future positions.

Blended energy costs are those for the whole energy system. Four cases are examined including the effects of lower storage costs and scheduling to share the power demand between stores. For this last case, the powers from Zachary[33] are used, with proportionately increased store sizes where applicable:

1. Current storage cost without power sharing
2. Current storage costs with power sharing
3. Future storage costs without power sharing.

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[32] Ziegler & Trancik (2019)
[33] Zay (2021)

4. Future storage costs with power sharing.

For the wholly renewable energy system in Figure 6 (below) energy costs are built up from the base renewable cost with overcapacity and the storage elements. In Figure 6, 30% baseload load (with energy costs of $/MWh based on future nuclear costs[34]) is included. These costs are shared or blended over the whole demand.

Four energy costs cases are shown (solid lines) for current and future storage costs, with and without sharing in each case. Components of the supply cost: base renewable energy cost and overcapacity are shown as dashed lines.

The contribution of storage to blended energy costs is significant. For current costs, blended energy costs are greater than $160/MWh – more than three times the base renewable cost. The lowest blended energy cost is at 40% overcapacity. At these levels, renewables plus storage costs look excessive, not providing the low costs transition to next-zero that is expected. Even for the lower future storage costs, blended energy costs are double the prime renewable energy cost. We can see that reducing storage costs will be crucial to the economics of these types of system and achieving blended energy costs of $100-110/MWh.

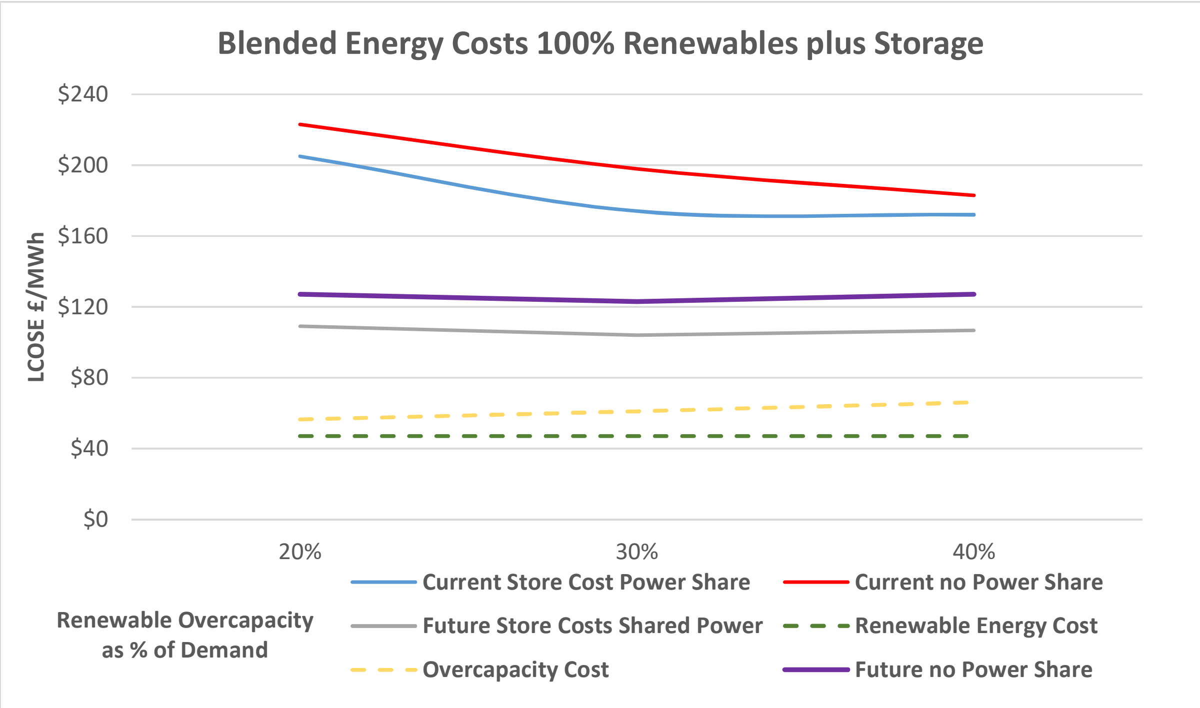

Figure 6. 2050 UK Energy System blended energy cost for wholly renewable system v overcapacity – mean storage costs and sharing of power demand between stores.

For future storage costs, energy costs are not as strongly affected by the level of overcapacity. At low levels of overcapacity the larger store size more than offsets the lower overcapacity costs and the two effects begin to cancel out as overcapacity increases. In each case, better scheduling reduces energy costs by $20-25/MWh. Using a 5% discount rate for storage reduces the energy costs by about $12/MWh for current storage costs and $7/MWh for future storage costs.

[34] CCC (2019)

Blended energy costs of $105/MWh for future storage costs at a 7% discount rate seem achievable, or $97/MWh at 5%. Further cost storage optimisation studies are required to conform the precise trade-off for overcapacity and scheduling.

The inclusion of baseload nuclear can lower the blended energy cost (Figure 7 below) but only when baseload costs are lower than the system cost – which is the case for the current (high) storage costs. Baseload power reduces the overall system energy costs for the current storage cost case by a about $10/MWh. For future storage costs with baseload energy costs are a few $/MWh higher than without. The main benefit of baseload supply is providing energy security through diversity of supply.

Energy costs are not sensitive to the level of overcapacity and better scheduling of storage reduced energy costs by $15-20/MWh. For future storage costs, blended energy costs are $110/MWh for a 7% discount rate and $106/MWh for 5%. Grid enhancement costs needed to be added – see above.

The use of for BECCS as an alternative to nuclear for baseload supply would not reduce system energy costs because BECCS costs are much higher – $230/MWh[35]. These could be offset by higher carbon credits in the future.

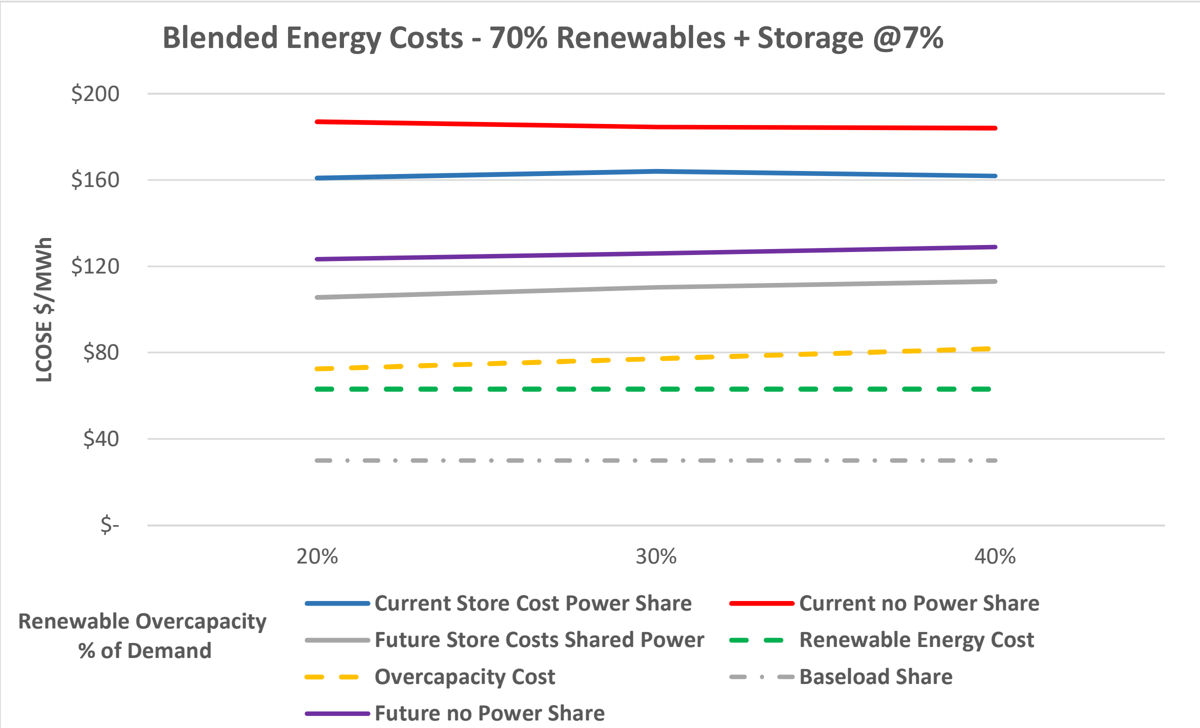

Figure 7. 2050 UK Energy System blended energy cost for 70% renewable share v overcapacity – mean storage costs and sharing of power demand between stores.

If individual stores are operated in 'Merchant' mode, buying and selling energy as the market determines, perhaps being backed by subsidy payments. Where stores are constrained to only complement renewable intermittency, the 'Merchant' mode will be expensive. Stand-alone energy costs for different storage technologies (for the 30% baseload and 30% overcapacity case) are high for even the lowest storage costs:

Short (Li-Ion): $263/MWh   Medium (CAES): $237/MWh Long (Hydrogen): $881/MWh

[35] Wood (2018)

These high energy costs are a result of the small amount of energy being traded each year, which adversely affects the economics of stores operating as 'Merchant' energy providers. If a 'Merchant' energy store were seeks to maximise its supply and hence its revenue, it would not function as modelled/scheduled. In such a case stores could be empty when required during long wind droughts. 'Merchant' storage would not provide a back-up to the power grid – evening out renewable supplies and demand fluctuations and ensuring system reliability This has implications for the control and ownership of the power grid and the needs to schedule the storage to ensure system reliability - sufficient energy is stored to cover extended periods when supply is less than demand.

Renewable energy systems with storage required for reliability of supply are expensive. Alternatives for flexible zero-carbon supply need to be explored, such as CCGT-CCS with DACC. Also, baseload low-carbon technologies such as nuclear energy or BECCS may be able to compensate for the large variations in supply and provide lower overall energy system costs. If so: how should these alternative supplies be scheduled, to both ensure supply reliability and minimise system energy costs?

If in the future storage and energy costs fall, blended energy costs of renewables plus storage in 2040 (~$100/MWh) would be similar to future nuclear costs and CCGT with CCS. A balanced energy strategy could include substantial amounts of renewable supply with energy storage, together with zero-carbon baseload supplies. This would both provide diversity of supply and also limit the rise in energy costs for net-zero.

Conclusions

Based on this preliminary analysis we can say:

- The provision of storage and overcapacity to make highly renewable energy systems reliable and dispatchable could double the system energy costs and would entail very high system capital costs ~ $600bn.
- Future costs for storage technologies are uncertain. They significantly affect the economics of the energy system. Lower future costs could be achieved by a combination of large scale production learning and the use of larger high pressure caverns for storing air and hydrogen.
- It is crucial that storage costs are reduced from current values, to make high penetration renewable energy systems with storage, economic – limiting the cost of achieving net-zero.
- It appears that between 20-30% overcapacity provides the lowest energy cost, but the trade-off between storage and overcapacity is weak and requires further work to confirm.
- Zero-carbon baseload supplies reduce the scale of the renewable energy supply and hence the range of fluctuation that must be accommodated. Only if the costs of such supplies are less than the renewable system cost, are the overall energy costs reduced.
- Scheduling of storage allows sharing of the power demand between storage technologies and improves the economics of energy storage.
- Blended energy costs for a 70% renewables will be $100-110/MWh, or ~ $120/MWh with grid enhancement costs.
- Stores operating solely in merchant mode appear to be uneconomic with standalone energy mean costs in the best case, more than $250/MWh. If stores operate to maximise their supply it is likely that insufficient energy would be available when renewable supplies are lower than demand for long periods of time and grid reliability would not be delivered.

- Economic alternatives to energy storage need to be considered - both BECCS with future carbon pricing and CCGT-CCS, with reductions of upstream methane emissions and improved carbon capture capability.

Future Work

Building on these studies the priorities should be to:

1. Optimise the storage cost elements, including the effect of different input and output power costs together with other cost drivers.
2. Better integrated storage scheduling with the economic analysis of the energy system.
3. Include the cost of enhancing the power grids into blended energy costs.
4. Consider the economics of flexible zero-carbon supplies as alternatives to energy storage.

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SI 9 The Grid, Markets, and Coordination

1 Introduction

There will be major changes in the scale and nature of the electricity system as the UK moves towards net-zero emissions:

- electricity will play an increasing role in transport, industry and heating, and annual demand for electrical energy will perhaps double;
- as the role of electricity grows, resilience of supply will become ever more vital [i].
- fossil fuel generation by plants that use synchronous machines will be phased down or out;
- intermittent wind and solar energy, generated at dispersed locations, will provide an increasing fraction of electricity supply, rising probably to well over 50%;
- the number of renewable sources connected directly to the distribution (rather than the transmission) network, which today are poorly monitored and controlled, will grow;
- there is likely to be a need for large-scale electricity storage, much in solution-mined salt caverns for which the potential is large but restricted to a few areas;
- large investments will be needed in wind and solar capacity and storage, in enlarging and strengthening the transmission grid to accommodate large inter-area power transfers, and in expanding the distribution network to support electrified heating and electric vehicle (EV) charging;
- investment decisions will have to be designed to ensure an appropriate balance between assets - generation capacity, different storage technologies and transmission – and services such as flexible demand;
- close coordination will be needed in operating the storage system in order to control its cost and ensure that demand for electricity can be met reliably.

Reliability is today largely underwritten by the availability of flexible, dispatchable gas generation with unabated CO_2 emissions, whose scale is set to reduce, while options such as backing up electrical power with diesel generators may not be available in the net-zero era. With high levels of variable renewables supported by storage, reliability will depend on a balance between the level of supply and storage volumes: if stored energy runs out, the lights really will go out when the wind is not blowing and the sun not shining.

It will be necessary to enlarge and strengthen the transmission grid to allow it to transport energy over long distances, from new (often remote) sites where it is generated to where it will be used or stored, and to deal with higher fluctuations, which in the future will be dominated by variations in supply rather than in demand, and higher peak loads. The technical issues involved in operating the power system in future are discussed in the first part of this Chapter.

[i] Resilience is the electricity system's ability to prevent, contain and recover from interruptions to supply resulting from disturbances

If the flexibility needed to complement high levels of wind and solar power is provided largely by storage, as envisaged in this report, markets will have to reward appropriately the providers of the essential but expensive energy that it provides. The modelling and costings discussed in the previous chapter assume that i) the level of wind and solar power and the portfolio of storage technologies are chosen to minimise the average cost of electricity, and ii) energy is placed in and dispatched from storage in a coordinated way, using a merit scheduling procedure designed to ensure that demand is always met. As discussed in the second part of this chapter, current market mechanisms are unlikely to be able to reward storage appropriately or ensure the coordination of investment and operational decisions needed to keep costs under control.

Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations

The commissioner's recommendations, the supporting companion report from the Energy Systems Catapult, and the Minister's initial response, were published on 4 August 2023, see https://www.gov.uk/government/publications/accelerating-electricity-transmission-network-deployment-electricity-network-commissioners-recommendations

The recommendations complement the considerations in this report.

2. Challenges for the Grid

The power system operator has to balance supply and demand at all times. The Operator has to keep the frequency within an acceptable range: for many years, the legal requirement in Britain has been to be within ±1% of 50 hertz[1] with plant connected to the system required to be capable of operating in a stable manner down to 47.5 Hz and up to 52 Hz[2]. Fault events such as forced outages of large generating units or interconnections to other countries cause the frequency to change quickly. To date, the System Operator's ability to meet the legal requirement in spite of such events has been aided by the kinetic energy stored in the rotating mass of conventional, synchronous generators plus the part of demand comprising directly connected motors which, together, comprise the system's inertia.

Distribution Network Operators (DNOs) are required[1] to keep voltages within a range, usually between -6% and +10%. Voltage that is too low can cause some equipment or appliances not to work, while being too high can raise safety issues. In addition, the System Operator has to ensure that all the elements are synchronised, and that power flows never become too large, so that transformers, cables and overhead lines do not overheat. Hitherto this has been achieved primarily by managing supply – to which in GB in 2020 gas, which is relatively flexible, still made the largest contribution (31%), just ahead of wind (30%), which was followed by nuclear (16%)[3, 4] and by making use of Britain's relatively small pumped hydro storage capacity.

The use of fossil fuels has given the system access to stores of energy and the ability to plan their use to meet demand as it varies through a day and through a year. Meeting the legal, security and quality of supply requirements while ensuring a high degree of reliability will become increasingly difficult in the face of the replacement of unabated use of fossil fuels with variable renewables. Measures that will help include: increased flexibility on the demand side, through the greater use of demand response contracts and incentives to influence the times at which electrical vehicles are charged, and other measures discussed in section 2.10; increased supply through interconnectors, although as noted in Chapter 2 it may not be available when most needed; and more pooling of generation resources to ensure adequate security of supply and flexibility.

Measures such as these will all help, but they will not have a major effect on the need to strengthen and enlarge the transmission network, and to ensure that it is able to deal with increased volatility and higher peak loads. The biggest issue is argued by many power systems engineers to be the retirement of synchronous machines in fossil plants[5,6]. These provide system inertia, reactive power to help to regulate voltages, 'black start' services to restore supplies should the system ever collapse, and high currents when short circuit faults occur on the network, helping to support voltages and allowing protection devices to detect faults and isolate them safely. The supply that will replace them – wind, solar, imports, and possibly much of the supply from storage – will use power electronic converters. They can be controlled extremely flexibly, such as to provide voltage control and, with a suitable source of energy, frequency response, but interactions between many grid-connected converters are hard to predict, particularly if details are hidden from the System Operator. Furthermore, their short-circuit current capabilities are strictly limited.

When combined with stores of energy that can be accessed very quickly, problems arising from reduction in the system's inertia can largely be overcome. There is, however, an urgent need for engineering research to guide how the controls of the increasingly ubiquitous power electronic converters should be defined and utilised, e.g. to be 'grid-forming' rather than 'grid-following', so that they can contribute to stable operation of the power system as a whole rather than, potentially, threaten it.

New modelling capability will be required to allow the System Operator to understand the impact of converters used in different ways. Furthermore, the uncertainty of wind and solar power and, at least in the short-term, new loads such as EV charging, result in increased variability of power flows. The number of potential providers of services aiding system operation, such as flexible demand and small scale 'distributed' generators, is also increasing[7]. These developments all highlight a need for new decision support tools based on advanced stochastic optimisation and capable of handling a very large number of variables. This should include modelling of different scheduling procedures for storage which, as discussed in Chapter 3, have received almost no attention.

These areas of research should complement work on the different forms of storage described in this report to produce a range of options that can provide the right mix of flexibility needed to ensure continued reliable, stable operation of a zero-carbon power system. As the future structure of GB's electricity system becomes clearer, scenarios should be developed that take account of the location of demand and supply and the sites that are expected to provide large-scale storage. These scenarios should balance operability and reliability against the average cost of electricity, which was found in the previous chapter to be rather insensitive to the cost of storage and the mixture of storage technologies that is deployed.

3 Markets and Coordination

3.1 Market Shortcomings

It is increasingly recognised that the transition to a low-carbon world cannot be left entirely to markets[8,9]. Major investment decisions have for many years been taken by government. Meanwhile, the idea that scarcity prices, either via unconstrained market force or administered means, could incentivise investment in the capacity needed in times of stress has been questioned as a result of the failure of (administered) scarcity prices in the ERCOT system in Texas in February 2021, while the storm around current UK gas retail prices shows that allowing prices to stifle demand will be resisted by consumers and the Government[10].

A high carbon price, which may not be politically or socially acceptable, would be very helpful, but it could not do the job on its own. Policy interventions will be needed to reduce risks for investors in expensive long-lived assets and ensure that investors in wind and solar capacity and storage are appropriately rewarded, while spot markets will need to be reformed or alternative mechanism introduced to ensure efficient operation. Defining appropriate instruments will depend on whether government or consumers will be expected to carry construction risks as well as long term price and market risks, and how costs are recovered, e.g. via consumers' bills or via taxation.

Reduction of investment risks

Investors in generation, storage and transmission are dependent on revenue streams over twenty or more years, during which regulations and other factors may change. In the case of storage, they will have to take a view on the future cost of buying energy, the price at which it could be sold, the optimum timing of sales, and the behaviour of competitors. Faced with so many uncertainties, investors typically require some form of long-term contractual assurance.

This could be provided by a regulated asset base – RAB – approach in which reasonably incurred costs are passed to consumers, as in the case of network investments and as has been proposed for a new nuclear power station at Sizewell. It could also be provided by long-term contracts underwritten by government commitments, e.g. via CfDs or feed in tariffs, which reduce investment risks thereby lowering the cost of capital, and have successfully incentivised investment in generation capacity[11]. In the case of storage, however, incentives based on output could lead to operators releasing energy whenever possible, leaving stores in profit but empty in a crisis when they are needed.

Rewarding provision with low marginal costs

In a competitive 'energy only' market, generators and operators of storage would be required to dispatch energy, and would be rewarded, on the basis of the merit order for dispatch of energy that reflects short-run marginal costs. Developers of wind and solar capacity would never be able to recover their investments on this basis as the marginal costs are close to zero. Stores whose content is turned over frequently could operate in merchant mode, recovering their costs through arbitrage (assuming coordination between operators of storage, and suppliers of energy to be stored, as discussed below). However, the large stores that this report argues will be needed to deal with rare weather events in systems with high levels of wind and solar supply could never recover their costs through arbitrage as they will be idle much of the time.

Possible remedies include:

- Capacity markets, in which key decisions are taken by a body which decides how much and what types of capacity are required, and depending on the rules it sets for capacity auctions, may also have a major impact on technical characteristics and location. In the case of storage, capacity could mean storage volume, and/or output power.
- A 'cap and floor' mechanism in which investors' income is largely determined by energy markets but their exposure to downside risk and potential upside gains are limited. The

approach is currently used for interconnectors in Britain and has been proposed for storage capacity by KPMG[12], in a report that observes that a 'Market-only' model would have the potential to perpetuate the financing issues for long-duration storage identified above.

Need to reform spot markets

The underlying problem is that traditional spot markets were designed to suit the operation of relatively flexible fossil fuel plants. They are unlikely to be suitable for or adaptable to new technologies with much more complex intermittency and operating constraints, such as wind, solar, and storage, or relatively inflexible nuclear. Finding a set of pricing arrangements that produce an optimal outcome will become increasingly difficult as i) the complexities of managing low carbon systems grow, and ii) scheduling and dispatch decisions increasingly relate to nuclear and more complex operating regimes needed with storage, rather than simple merit order ranking. There is no obvious solution to this problem, apart from optimised scheduling and dispatch across large, commonly owned or coordinated portfolios, or carried out centrally for a large proportion of all resources on the system.

3.2 The need for coordination

It is widely recognised that reaching net-zero emissions cost-effectively will require far greater coordination and 'whole system' approaches that extend across the electricity system, heat and transport, see e.g. the IET/ Energy Systems Catapult Review of Future Power System Architecture[13] and Council for Science and Technology, *Achieving net zero carbon emissions through a whole systems approach*, August 2020[14]. The advent of large-scale storage, as well as low carbon generation technologies with more complex or stochastic output profiles, will increase the need for the coordination in both:

- **Investment,** to ensure a combination of renewable resources and storage that is optimal in terms of diversity, system compatibility and location. Current markets may lead to investment in storage designed to provide grid services (which are likely to attract capacity payments) and short-term arbitrage/peak shaving, but is hard to imagine them incentivising construction of large-scale long-term storage as part of an optimal portfolio.
- **Scheduling** the assignment of energy to and dispatch from different types of store, over periods from hours to many months. It is hard to see how the withholding of a certain volume from shorter-term markets in order to conserve reserves could be achieved by independent actors responding to short term market signals and forecasts of future prices, or how complex system risk assessments and judgements, usually the preserve of the System Operator, could be easily translated into market signals.

4 The need for reform

Changes will need to be made to existing institutions and markets to meet the challenges raised by the growth of renewables and the potential advent of large-scale storage[15]. Examples of alternatives that might be better able ensure a rapid and cost-effective transition to a net-zero electricity system are given below. This is not to say that more cannot be done with more aggressive use of carbon pricing, encouraging low carbon supply through the continued use of contracts for difference (CfD)[1], the development of the capacity market, and improving retail tariffs, designed to unlock the potential for demand side measures.

Internationally, centrally driven coordination of investment plans, or less formal agreements to share information and plans with similar effect, are quite common. Examples include France, where investment in generation is in the hands of a single company (EdF), and Germany with its Energiewende, a complex mix of federal and state policies and governance[2]. US power pools are typically umbrella organisations, whose membership may include the utilities, generators and other stakeholders. They implicitly assume responsibility for reliability and by their nature provide opportunities for formal or informal coordination within the sector. The need for coordination is widely recognised[16,3], but can raise anti-cartel and competition policy questions, as when Dutch generators attempted to reach agreement to close coal stations and increase gas consumption[17,18].

Whatever arrangements are adopted should allow investments in generation, transmission (including interconnectors) and storage to compete on a level playing field, and be evaluated using common criteria. Current regulation prohibits owners of transmission and distribution networks from owning storage, which is treated as generation. Consequently, some DNOs are considering contracts with owners of storage as an alternative to investing in new network assets. However, storage owners will not make large investments dependent on long-term revenue streams without ultra-secure long-term guarantees provided by the regulatory framework or a long-term contract or both. Network owners, for their part, have hitherto appeared reluctant to enter into such long-term contracts as network capacity (but not necessarily storage) has the advantage that the cost can be recovered over a long period within the regulatory framework.

Turning to future arrangements, two possibilities will be described, with the aim of provoking reflection and debate. The first, advocated by Sir Dieter Helm[19], would deal with intermittency by conducting reverse auctions of the obligation to provide dispatchable ('firm') power and/or peak power. This would delegate responsibility for reliability to the parties that won the auction. It would require owners of intermittent generation, who generally do not own (or have the expertise needed to provide) storage, to form consortia with those who do, and/or form consortia with other suppliers[4]. Large consortia would be able to deliver much of what is needed. It could be feared, however, that they might reduce competition, increase the potential

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[1] CfDs comprise a payment for the difference relative to a reference price, which can be hard to set in the absence of a liquid existing market. So, for instance, a green hydrogen CfD might be set relative to a conventional hydrogen reference price, although such markets would ideally be more liquid. For green shipping Clark et al (2021) suggest a conventional marine gas oil (MGO) reference price. One alternative is to impute the carbon saving from the green technology and offer a fixed carbon contract (where payment is made directly for the carbon saved at a fixed price (Helm and Hepburn, 2007), or a Carbon Contract for Difference, where the reference price is (say) the carbon price in an emissions trading scheme (see Vogl et al, 2021 for a steel-based example).

[2] A useful description of German coordination issues in the Energiewende is in the following: Ohlhorst, D. (2015). Germany's energy transition policy between national targets and decentralized responsibilities. *Journal of Integrative Environmental Sciences*, *12*(4), 303-322. https://www.tandfonline.com/doi/full/10.1080/1943815X.2015.1125373

[3] McKinsey commented in 2010 that both Europe and German transformation paths were leading to unnecessarily high costs and that a cost optimal transformation required coordinated European action.

[4] Such consortia already exist: they provide the means to buy shortfalls or sell surpluses in day-ahead and intraday markets and help to hedge risks

for market abuse, raise a barrier to entry for smaller innovative firms, and discriminate against more decentralised systems.

The second approach would be to recognise more formally the growing need for coordination both of procurement of generating and storage capacity with different capabilities, and of operational decisions (which will be especially important for scheduling storage). One radical possibility would be to create a 'central buyer', responsible not only for procuring capacity, but also for buying power from generators and selling it to retail suppliers or large consumers. The central buyer, whose tasks would include arranging for energy to be supplied to, and dispatched from, storage, would be obliged to consider whole system benefits when taking investment and operational decisions. In this respect, while not owning generation, storage or transmission, a central buyer model would effectively be similar to public ownership, but without removing competition and requiring taxpayers to bear all risks. The proposed Future Systems Operator (FSO) is one of candidates for such a role[5].

5 Conclusions

Moving to high levels of wind and solar supply will put new and challenging demands on the transmission grid and on the electricity market.

Large-scale underground storage of hydrogen, which this report finds to be the leading option for large-scale storage, will add to the need to enlarge and strengthen the grid because suitable sites are only found in a few areas. More research and modelling are needed on the design and operation of a larger grid, supplied largely by volatile wind and solar energy, with relatively few synchronous sources, but there appear to be no showstoppers.

Storage will also complicate the task of identifying and ensuring investment in a portfolio of facilities (generating capacity, different types of stores, transmission) that will make it possible to reach net-zero emissions cost effectively. It is unclear whether market mechanisms of the types already in place could, suitably strengthened, deliver what is needed. It is, however, very hard to imagine them delivering the close cooperation that will be needed to operate a large-scale storage system effectively. New structures are likely to be needed to deal with the problem which, in a nutshell, is that competing generators and suppliers have no individual responsibility for the system as a whole. A starting point for developing future commercial and regulatory arrangements must be a clear recognition of the challenges; and then how, and by whom, investments in generation, storage and networks are compared and evaluated.

[5] Independent Future System Operator (FSO). The Electricity System Operator (ESO) function of National Grid was split from its network owner function in April 2019 and the ESO was given responsibility not only for balancing the system in real time, but also for coordination of investments to enhance the capacity of the main interconnected transmission network. The UK government consulted on their proposal for an independent Future System Operator in July 2021. The outcome is awaited.

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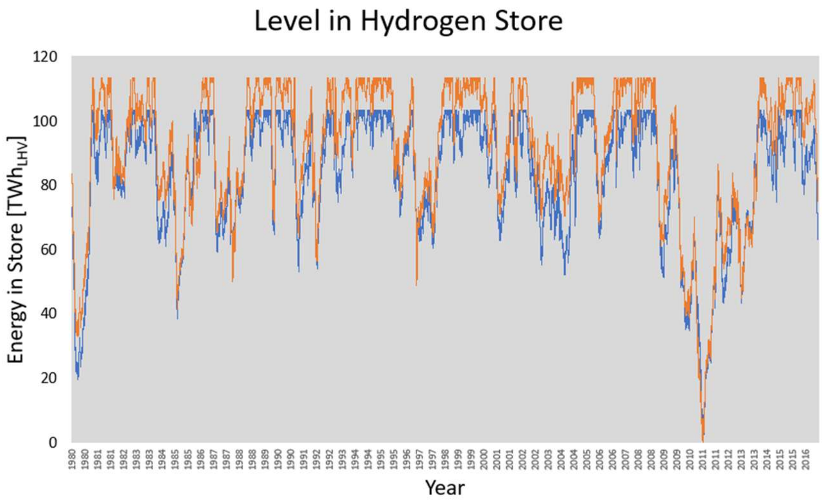
Stop Press

Effect of Demand/Weather Correlations

The modelling in the Report compares AFRY's hour-by-hour model of demand in 2050, which is based on the weather in 2018, with the Renewables.ninja model of wind and solar supply in each of the years 1980-2016. It therefore does not take account of the correlation between supply and demand due to the weather. Further steps that are needed, which are listed in Section 10.2 of the Report, include *Develop models of electricity demand that take proper account of correlations with the weather*.

Very recently, Iain Staffell has attempted to remove correlations with the weather in 2018 from AFRY's model and replace them with the correlations in the years 1980-2016, using the Demand.ninja model that he developed with Stefan Pfenninger and Nathan Johnson, which is described in a forthcoming Nature Energy article[1] and is outlined briefly below. It is not possible to perfectly extrapolate energy demand to other years of weather conditions (the difficulties are described below), but nevertheless Staffell's weather corrected data can be used to estimate the magnitude of the impact of correlations on the need for storage.

The impact was studied[2] in the case of hydrogen storage only by comparing the level of hydrogen in the store over 37 years if i) ignoring correlations (as in Fig 13 of the report), and ii) including them using Staffell's results. The level of hydrogen in the store that is found in these two cases is shown below for wind + solar supply averaging 741 TWh/year, using the central values for the costs of electrolysers and storage. In both cases, in finding the electrolyser power and storage capacity that minimises the overall cost *it was anticipated that 20% contingency would be added to the size of the store, although to ease comparison this is not shown in the figure.*



Without correlations, the electrolyser power is 89.4 GW and the storage volume (without contingency) is 102.6 TWh$_{LHV}$ at the cost minimum. With correlations included, the electrolyser power is 87.3 GW and the storage volume (without contingency) is 113.5 TWh$_{LHV}$. The increase of 10.6% in the storage volume, which is uncertain by an unquantifiable amount, is

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[1] I. Staffell, S. Pfenninger, N. Johnson, 2023. *A global model of hourly space heating and cooling demand at multiple spatial scales.* Nature Energy (in press). https://doi.org/10.1038/s41560-023-01341-5

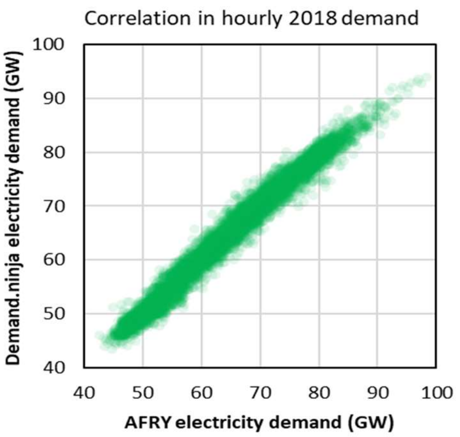
[2] By Chris Llewellyn Smith and Richard Nayak Luke in collaboration with Iain Staffell

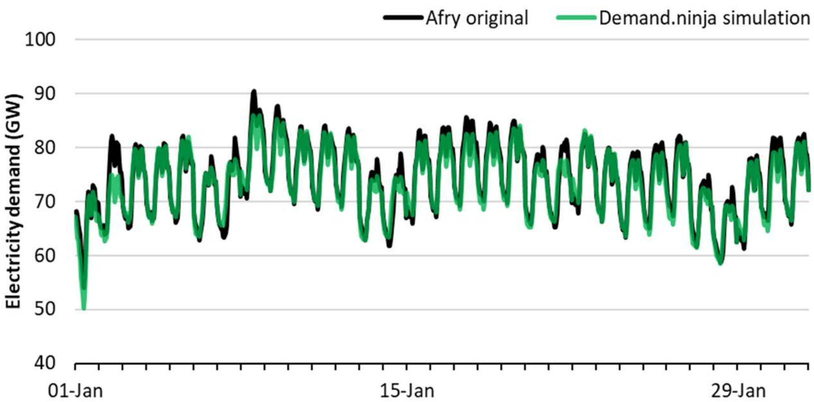
well within the 20% contingency that was included to allow for weather effects not seen in the 37 years studied, which (as argued in section 2.4.1) also provides protection against underestimates of the need for storage. The model discussed in SI 2.3 and SI 2 Annex B showed that correlations between demand and the weather are likely to be washed out over periods longer than three years. However, the storage volume is set by the size of the drop in the level of hydrogen in the store in the three years that precede the minimum. It is therefore to be expected that correlations increase the size of the drop and the need for storage.

Turning to the uncertainties:

The Demand.ninja process used by Staffell is analogous to the Renewables.ninja method for synthesizing output from wind and solar generators. It correlates meteorological data with energy demand, to disaggregate demand into components for heating and cooling (which are weather-driven) and all other sources (which are not). The model uses temperature, wind speed, solar irradiance and humidity data covering the British Isles, and was correlated to the national hourly electricity demand from the AFRY model. The approximate architectural characteristics of the UK building stock were incorporated, namely insulation levels, airtightness and glazed area, through prior analysis described in Ref 1.

This approach cannot perfectly strip out the weather correlations from 2018 in AFRY's model, as energy demand is the driven by human activity which is influenced by many factors other than the weather. However, the correlation between the Demand.ninja simulation for 2018 weather and the AFRY demand has an R^2 coefficient of 0.988 (see Figures below and mean absolute error of 1.23 GW or 1.30% [1.25%] of the maximum demand of 93.9 GW [98.4 GW] in the corrected [uncorrected] data. This is consistent with the model's performance at simulating historical electricity in Great Britain, Europe and the United States.[1]





Over the period 1980-2016 the correlation between the weather corrected and uncorrected demand data has an R^2 coefficient of 0.883, while the average of (corrected demand)/(AFRY uncorrected demand) is 1.0065 (implying the average climate year has 0.65% higher electricity demand than 2018). For 2018 the average is 1.0005 which provides another measure of Staffell's success in stripping out and then reinserting correlations. To meet the additional average demand of 0.0065 x 570 = 3.7 TWh_e/year requires an additional supply of 137 TWh_e over the whole period of 37 years. It is available because, with weather and demand better correlated, slightly less supply has to be curtailed when it is high as correlations typically increase demand in this case, while when supply is low the correlations tend to decrease demand and more supply is available to be used directly or stored[3].

[3] The level in the store is set to be the same at the beginning and end of the 37-year period (11 TWh_{LHV} higher with than without correlations), but due to inefficiencies it acts as a net sink of electricity.

The drop in the level of store in the period from February 2009 to May 2011, when it falls from the maximum to a minimum, is the result of the low level of wind supply in this period, which can be seen in Fig SI 2.6 C (the unusual conditions in this period lead to a below average R^2 coefficient of 0.847 but there is nothing unusual about the <corrected data/uncorrected data> which is 1.0056[4]).

Concluding remarks

AFRY apparently included some demand management measures (in the form of peak shaving/shifting) in their model of demand. This provides an additional source of uncertainty, although applying these measures over the 37-years studied would tend to reduce the estimated need for storage.

Subject to this uncertainty, the conclusion of this analysis is that the effect of including demand/weather correlations is comfortably within the 20% contingency that was allowed for in the report, although this conclusion would be undermined by wind droughts that last very much longer than those seen in the 37 years that were studied.

[4] The additional drop of 10.9 TWh_{LHV} in the level of the store that results from including correlations provides an additional 10.9 x assumed conversion efficiency of 55% = 6.0 TWh_e. This is consistent with the need for an additional 0.0056 x 570 x 2 1/4 years = 7.2 TWh_e some of which will be provided directly.

Errata

On page 26 of the printed version of the report:

In the labels of the x-axis of Figure 11, 400k and 450k should read 300k and 350k

On page 38 of the printed version of the report, in section 4.3:

The estimate of the cost/mile of transporting hydrogen is misleadingly large for reasons explained in an updated text on page 93 of the Supplementary Information. More realistic estimates of the cost of transporting hydrogen are provided in a note on Transmission of Electricity which can be found at https://www.era.ac.uk/event/Royal-Society-largescale-energy-storage-event/

On page 94 of the printed version of the report:

Reference 2 should be Working Paper 23-02, ISSN 2732-4214

On page 86 of the printed version of the report:

1/3 down the left-hand column the expressions for NPVs should read:

NPV of costs = $\sum_n$ (total capex and opex in year n) / $(1 + \text{discount rate})^n$

NPV of electricity generation = $\sum_n$ (net generation in year n) / $(1 + \text{discount rate})^n$

At the bottom of column, the last expression should read:

$[1 – (1/(1+d)^N]/d$