AGENDA

SELECT COMMITTEE - RENEWABLE ENERGY

Thursday, 27 May 2010 at 2.00 pm	Ask for:	**Christine Singh/Sue Frampton**
Wantsum Room, Sessions House, County Hall, Maidstone	Telephone:	**(01622) 694334 or 694993**

Tea/coffee will be available before the meeting

Membership

Conservative (7): Mr K A Ferrin, MBE (Chairman), Mr C Hibberd, Mr D A Hirst, Mr R E King, Mr C P Smith, Mrs P A V Stockell and Mrs E M Tweed

Liberal Democrat (1): Mr T Prater

UNRESTRICTED ITEMS

(During these items the meeting is likely to be open to the public)

Item No		Timings*
1	Mark Willingale, David Cook and Matthias Hamm, Metrotidal (Pages 1 - 2)	2.15 pm
2	John Park, Infrastructure Planning Engineer, Dick Polley, Energy Planning Manager South and Mike Dixon, Engineering Projects Manager (Pages 3 - 4)	3.15 pm
3	Additional Documents are included as background reading for the meeting (Pages 5 - 38)	

At the end of the public session Members of the Committee should remain in the meeting room for 15 Minutes for summing up

EXEMPT ITEMS

(At the time of preparing the agenda there were no exempt items. During any such items which may arise the meeting is likely NOT to be open to the public)

Peter Sass
Head of Democratic Services and Local Leadership
(01622) 694002

Wednesday, 19 May 2010

Metrotidal

David Cook MA(Hons) DipArch(Cantab) RIBA

After completing his architectural training at Cambridge, David Cook spent five years in New York working on a wide range of commercial and residential award winning projects. Whilst in the United States he taught architecture at Carnegie Mellon University in Pittsburg. He is now principal of David Cook Architects which specialises in residential, educational and institutional projects as well as Historic Buildings work. His practice has completed prestigious commissions for Dulwich College, Harrow School, The Palace of Westminster, Country Houses Association and The Royal Institute of British Architects.

Dipl.-Ing.(Fh) Matthias Hamm AADipl ARB AKH

Matthias Hamm has architecture diplomas from the Fachhochschule Trier, Germany and the Architectural Association in London. He is director of spaceAgent Architects based in London and Barcelona, with architectural projects throughout Europe with a strong emphasis on design and sustainability. He is an inventor of a number of high-tech housing and building systems with focus on prefabrication and mobility and is involved in IT and mobile phone technology. Other involvements have been the development of textile architecture and business concepts. He also has a wider interest in the interaction of politics and the built environment.

Mark Willingale MA(Cantab) AADipl RIBA

After graduating from Cambridge and completing his diploma at the Architectural Association, Mark Willingale formed Willingale Associates, Architects and Development Consultants, focusing on commercial and residential developments in Central London. His practice undertakes a wide range of conversion and refurbishment work, while also advancing the conception and feasibility of larger scale, mixed-use projects through to planning. He has broad experience of planning and design procurement having served on consultative bodies, chaired local amenity groups and advised on planning policy at public enquiries

> Tom Delay, chief executive of the Carbon Trust, said:
>
> *"The UK must urgently diversify, decarbonise and secure its energy sources and marine energy could over time provide up to 20% of the UK's electricity. Generating electricity from the UK's powerful wave and tidal resource not only plays a crucial role in meeting our climate change targets but also presents a significant economic opportunity for the UK. Wave alone presents a £2 billion economic opportunity for the UK."*

Suggested Themes and Questions (on the next page)

Suggested Themes and Questions

1. Could you please introduce yourselves and your organisation.

2. Could you explain the process of tidal pumped storage.

3. Where in Kent are there opportunities for pumped-storage tidal pools?

4. What is the capacity of the tidal and wind power proposed for Kent – will it, for example, provide any additional capacity for the grid?

5. Could you briefly outline your proposals for a multi-modal tunnel under the Thames, concentrating on the plans to utilise renewable energy within the project.

6. We are interested in identifying ways to maximise benefits to Kent residents and businesses from the development of renewable energy and other low carbon technologies - what benefits in terms of "Green Growth" do you believe the tunnel could bring to Kent?

EDF Energy Networks

Mike Dixon – Engineering Projects Manager

Mike is currently working on asset management strategies and investment for EDF Energy's three electricity distribution networks, serving East Anglia, London and the South East. Mike joined EDF Energy (previously Eastern Electricity) in 1987. He started his career with the Merseyside and North Wales Electricity Board (MANWEB). In 2000, Mike led the creation of stakeholder Steering Groups to direct investment in the undergrounding of overhead lines in Protected Areas within the East and South East networks. Mike is a Chartered Engineer, MIET and MIAM. He is active in community affairs and is Chair of his local Parish Council.

John Park – Infrastructure Planning Engineer

John joined Seeboard in 1964 where he held a number of posts before moving to Southern Electricity Head Office as a Substation Design Engineer. In the mid 70's he returned to Seeboard in a similar role before becoming the Company's Drawing Office Manager. A switch in career then saw him take up a series of posts within Asset Management where he managed a number of successful high profile projects before joining Infrastructure Planning with a particular focus on developing close relationships with Local Authorities and Government Agencies. In recent years John has concentrated his efforts on assisting Local Authorities in developing their LDF's with an emphasis on 'Core Strategy' issues associated with infrastructure provision. Ensuring that Authorities at both local and regional levels understand the importance of working with EDF Energy is vital to the process of producing timely and adequate electricity infrastructure investment schemes across the region.

John is a Member of the Institution of Engineering and Technology and is a Registered Member of the Association of Project Safety.

Dick Polley – Planning Manager (South)

Dick is currently responsible for the planning of EDF Energy's networks in London and the South East to ensure that their development keeps pace with the changing demands upon them. In a career of almost 40 years, initially with Seeboard, and latterly with EDF Energy, Dick has fulfilled a wide variety of engineering and management roles encompassing operations and strategy in addition to his present planning responsibilities. Prior to taking up his present role in 2005 he was responsible for the operation of the Network Control and Trouble Management Centre for the network in the South East. An honours graduate in electrical engineering, Dick is a Chartered Engineer and Fellow of the Institution of Engineering and Technology

Suggested Themes and Questions

1. Could you tell us about the electricity distribution network and highlight any particular issues for Kent.

2. Could you please tell us about the capacity of the grid and highlight any challenges arising with regard to renewable energy generation at different scales in Kent? Can the distribution network in Kent cope with the added load from distributed generation – how is this being managed and what are the issues?

3. Could you comment on energy security and uncertain gas supplies – in your view how urgent is the electrification of heating and transport and what do you believe is the role of the public sector with regard to this?

4. We have heard evidence about a CHP plant which can operate in island mode or parallel mode so that customers receive seamless supplies – are there similar arrangements for renewable energy generation:

   - What then, are the arrangements for households or larger sites generating renewable electricity – in respect of connection to the network to 'feed in' excess generation or to take power from the network if needed?
   - Are sites generating their own electricity immune from problems with the network resulting in power cuts elsewhere?
   - Recently there have been a number of power outages in Maidstone which have, for example, affected our HQ buildings – are you able to 'throw any light' on the kinds of issues that might be to blame in this case? Would KCC buildings be less likely to experience these problems if there was onsite generation?

5. The review has heard that "Large scale energy storage is critical to managing intermittent renewable energy sources". What are your views on this and can you comment on current solutions under consideration, and the possibilities for Kent.

6. Could you tell us about network issues associated with electric vehicle charging?

7. One means of reducing the load on the network by organisations such as KCC is by effecting behavioural changes –energy monitoring devices are one way of raising awareness about energy usage – from your experience, can you comment on the effectiveness of such measures and whether they are cost effective?

8. Could you please comment on the importance of infrastructure planning. What, in your view, are the key actions for local authorities in ensuring that future infrastructure needs are met?

9. The select committee has heard that one barrier to the progressing of renewable area schemes in rural, off grid, areas - is the cost of obtaining an initial survey and advice on network connections - can you comment on your industry's response to meeting these needs - what could be done to assist progress?

Enhancing Electrical Supply by Pumped Storage in Tidal Lagoons

David J.C. MacKay
Cavendish Laboratory, University of Cambridge
mackay@mrao.cam.ac.uk

March 13, 2007 – Draft 1.8 – first published 5/3/07

Summary

The principle that the net energy delivered by a tidal pool can be increased by pumping extra water into the pool at high tide or by pumping extra water out of the pool at low tide is well known in the industry. On paper, pumping can potentially enhance the net power delivered by a factor of about four. However, pumping seems generally to be viewed as a minor optional extra, delivering only a modest power enhancement. Two possible reasons why pumping is not emphasized in tidal designs are that increasing the vertical water range introduces additional costs (for example, higher walls), and that alternating between pumping and generating worsens the intermittency-of-supply problem from which simple tide pools suffer.

The intermittency-of-supply problem also causes problems for wind. How can we switch to wind power if the wind might stop blowing for two days at a time? Chemical or kinetic-energy storage systems are an economical way to smooth out the fluctuations of wind power on a time-scale of minutes, but what about hours and days?

Perhaps a shift of perspective on tidal lagoons is helpful. I sketch designs for a large pumped-storage system located at sea-level with a dual purpose: first, it can turn power that is poorly matched to demand into high-value demand-following power; and second, it can simultaneously serve as a tidal power station. Large designs with a capacity of several gigawatts are the most economical.

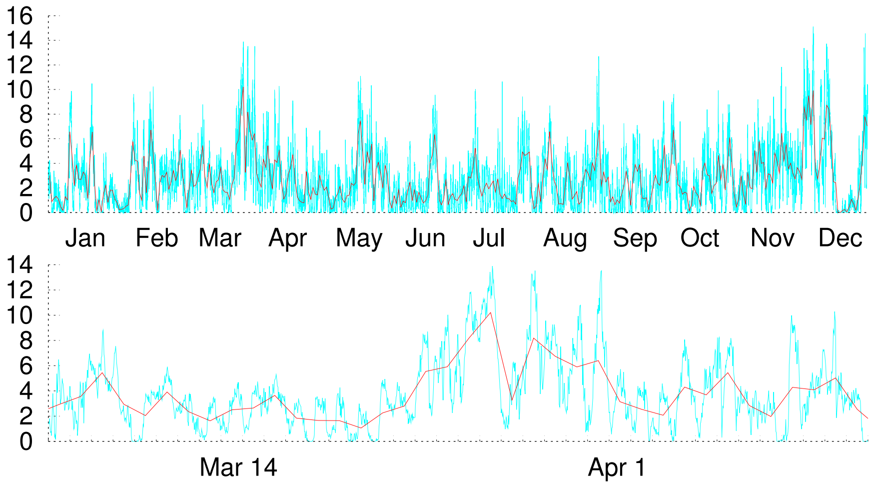


Figure 1. Cambridge mean wind speed in metres per second, daily (heavy line), and half-hourly (light line) during 2006. The lower figure shows detail from the upper. Thanks to Digital Technology Group, Computer laboratory, Cambridge This weather station is on the roof of the Gates building, roughly 10 m high. Wind speeds at a height of 50 m are usually about 25% bigger.

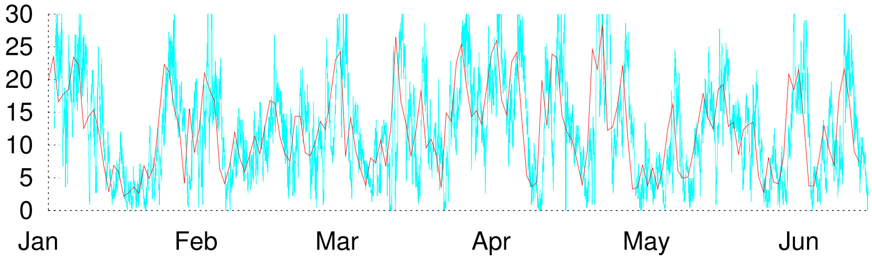


Figure 2. Cairngorm mean wind speed in metres per second, daily (heavy line), and half-hourly (light line), during six months of 2006. Thanks to Heriot–Watt University Physics Department.

Storage and wind

Offshore wind farms deliver, on average, about 3 W per m^2 of sea-floor area (or 3 MW/km^2, if you prefer).

Imagine that Britain had '30 GW' of wind farms – fifteen times as much as today. I put quotes round '30 GW' to emphasize that the nominal capacity of wind farms is much bigger than the average power delivered. The standard 'capacity factor' in the UK wind industry seems to be 1/3, so 30 GW of wind farms would be expected to deliver, on average, 10 GW.

Winds fluctuate (figures 1, 2). So this average of 10 GW would be delivered burstily: 30 GW one hour, and 0 GW the next, on one day; and perhaps 0 GW all day on the following day. How can such bursty power be made useful to society?

The default approach is to build back-up stations using some other sort of power – most likely fossil fuel – which sit idle when the wind blows, and are switched on when it does not, or when demand peaks. Another approach would be to manage demand – using smart electric-car chargers, for example, which use electricity when it is cheap; or running the Aluminium plant and the water-purification factory only when the wind blows. A third approach is storage. The storage required to deliver 10 GW for 24 hours is

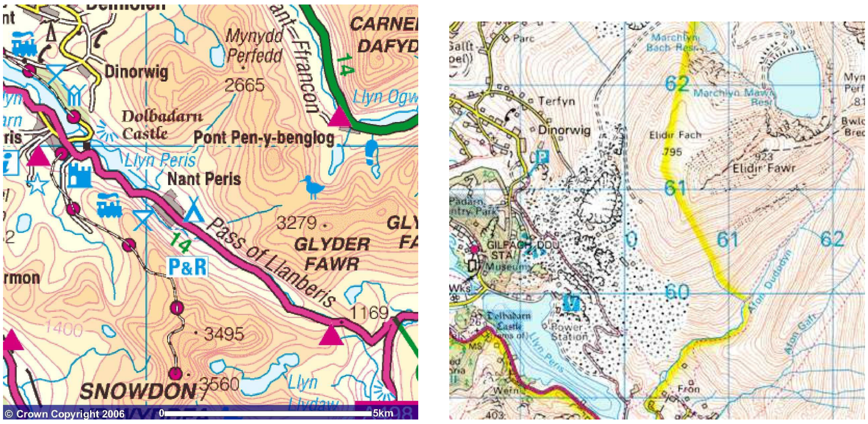


Figure 3. Dinorwig, in the Snowdonia National Park. The left map is a 10 km by 10 km area. In the right map the blue grid is made of 1 km squares. Dinorwig is the home of a 9 GWh storage system, using Marchlyn Mawr (615E, 620N) and Llyn Peris (590E, 598N) as its upper and lower reservoirs. Images produced from Ordnance Survey's Get-a-map service `www.ordnancesurvey.co.uk/getamap`. Images reproduced with permission of Ordnance Survey. © Crown Copyright 2006

240 GWh – twenty-six times as big as the 9 GWh of Dinorwig.

The Scottish island of Fair Isle (population 70, area 5.6 km^2) has pioneered several of these technologies. To solve the demand-management problem, Fairisle has for over 25 years had *two* electricity networks that distribute power from two wind turbines and, if necessary, a diesel electric generator. Standard electricity service is provided on one network, and electric heating is delivered by a second set of cables. The electric heating is mainly served by excess electricity from the turbines that would otherwise have had to be dumped. Remote frequency-sensitive programmable relays control individual water heaters and storage heaters in the individual buildings of the community. In fact there's up to six frequency channels per household, so the system behaves like seven networks. Fair Isle also successfully trialled a kinetic energy storage system (a flywheel) to store energy during oscillations of wind strength (with a period of 12 to 20 seconds).

Designs for multi-purpose storage/tidal systems

Key ideas for an energy-enhancing pumped-storage system:

1. It is said that connecting large numbers of wind turbines to the national electricity grid could lead to instabilities. We thus propose decoupling wind turbines from the grid, *plugging them directly into pumped storage systems instead.* The wind-to-pump connection could be a flexible grid with much wider tolerances than the national network.

2. The pumped storage system is located in a region with large

tides. Water is pumped to and from the sea in such a way that (a) the power delivered can respond to the grid's demand, eliminating problems of intermittency; and (b) we get more power out than we put in. (Yes, I mean that the energy delivered when generating *exceeds* the energy received – in contrast to Dinorwig, which has a round-trip efficiency of about 75%.)

3. When the demand for pumped storage is low (during a few calm days, say), the facility can also function as a stand-alone tidal power station. By using multiple lagoons, it's possible to turn the intrinsically intermittent tidal power into always-on, demand-following capacity.

4. The facility could also buy electricity from the national grid for pumped storage, just like Dinorwig.

In sum, it's a storage system that is more than 100% efficient. It's a storage system that can also produce its own power when it's not needed for storage. Or, it's a tidal facility that still provides a valuable function even when the tides are small.

Rough models

Let's assume a tidal range of $2h = 4\,\mathrm{m}$ throughout. I'll also assume that hydroelectric generators have an efficiency of 90% and that pumps have an efficiency of 85%. (These figures are based on the pumped storage system at Dinorwig, whose round-trip efficiency is about 75%. I am not sure what the best figures are for low-head tidal turbines. In their paper based on La Rance, Shaw and Watson [2003a] assume pumping efficiencies up to 66%, with best efficiency at large head, and generating efficiency 80%.)

Let's start by finding some benchmarks for energy production.

Production on ebb and flow (no pumping, no demand-following)

THE POWER OF AN ARTIFICIAL TIDE POOL. To estimate the power of an artificial tide pool, imagine that it's filled rapidly at high tide, and emptied rapidly at low tide. Power is generated in both directions. The change in potential energy of the water, each six hours, is mgh, where h is the change in height of the centre of mass of the water, which is half the range (figure 4). The mass per unit

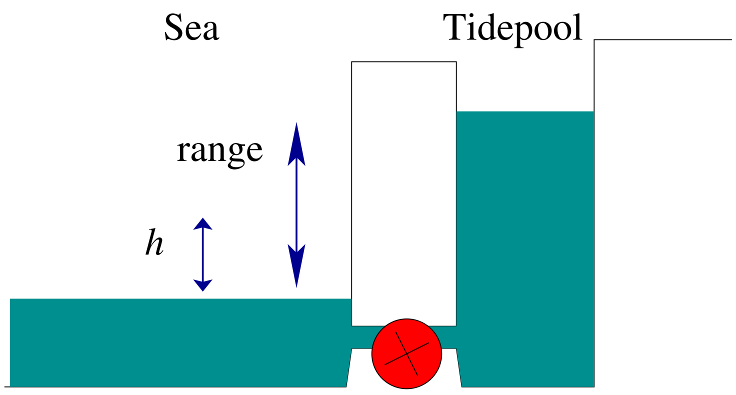


Figure 4. An artificial tide pool. The pool was filled at high tide, and now it's low tide. We let the water out through the electricity generator to turn the water's potential energy into electricity.

land-area covered by tide-pool is $\rho \times (2h)$, where ρ is the density of water ($1000\,\mathrm{kg/m^3}$). So the power per unit area delivered by a tide pool is

$$\frac{2\rho h g h}{6\,\text{hours}}$$

Plugging in $h = 2\,\mathrm{m}$, we find

$$\text{Power per unit area of tide-pool} = 3.6\,\mathrm{W/m^2}.$$

Allowing for an efficiency of 90% for conversion of this power to electricity, we get

$$\text{Power per unit area of tide-pool} = 3.3\,\mathrm{W^{(e)}/m^2}.$$

(Or $3.3\,\mathrm{MW/km^2}$.)

Tidal pools with pumping

The pumping trick artificially increases the amplitude of the tides in the tidal pool so as the amplify the power obtained. The energy cost of pumping in extra water at high tide is repaid with interest when the same water is let out at low tide; similarly, extra water can be pumped out at low tide, then let back in at high tide. Let's work out the theoretical limit for this technology.

I'll assume that generation has an efficiency of $\epsilon_{\mathrm{g}} = 0.9$ and that pumping has an efficiency of $\epsilon_{\mathrm{p}} = 0.85$.

Let the tidal range be $2h$. I'll assume that the prices of buying and selling electricity are the same at high tide and low tide, so that the optimal height boost b to which the pool is pumped above high water is given by (marginal cost of more pumping = marginal return of water):

$$b/\epsilon_{\mathrm{p}} = \epsilon_{\mathrm{g}}(b + 2h)$$

Defining the round-trip efficiency $\epsilon = \epsilon_{\rm g}\epsilon_{\rm p}$, we have

$$b = 2h\frac{\epsilon}{1-\epsilon}$$

For example, with a tidal range of $2h = 4\,\rm m$, and a round-trip efficiency of $\epsilon = 76\%$, the optimal boost is $b = 13\,\rm m$.

Let's assume the complementary trick is used at low tide. (This requires that the basin have a vertical range of 30 m!) The delivered power per unit area is then

$$\left(\frac{1}{2}\rho g \epsilon_{\rm g}(b+2h)^2 - \frac{1}{2}\rho g \frac{1}{\epsilon_{\rm p}} b^2\right) \Big/ T,$$

where T is the time from high tide to low tide. We can express this as the power without pumping, scaled up by a boost factor

$$\left(\frac{1}{1-\epsilon}\right),$$

which is a factor of about 4.

Tidal amplitude h (m)	Optimal boost height b (m)	Power with pumping (W/m^2)	Power without pumping (W/m^2)
0.5	3.3	0.9	0.2
1.0	6.5	3.5	0.8
2.0	**13**	**14**	**3.3**
3.0	20	31	7.4
4.0	26	56	13

Unfortunately, this pumping trick will rarely be exploited to the full because of the economics of basin construction: full exploitation of pumping requires the total height of the pool to be roughly 4 times the tidal range, and increases the delivered power by a factor of 4. But the material in a sea-wall of height H scales as H^2, so presumably the cost of constructing a wall four times as high will be more than four times as great. Extra cash would probably be better spent on enlarging a tidal pool horizontally rather than vertically.

The pumping trick can nevertheless be used for free whenever the natural tides are smaller than the maximum tidal range. The next table gives the power delivered if the boost height is set to h, that is, the range in the pool is just double the external range.

Tidal amplitude h (m)	Boost height b (m)	Power with pumping (W/m^2)	Power without pumping (W/m^2)
0.5	0.5	0.4	0.2
1.0	1.0	1.6	0.8
2.0	**2.0**	**6.3**	**3.3**
3.0	3.0	14	7.4
4.0	4.0	25	13

A doubling of vertical range is plausible at neap tides, since neap tides are typically about half as high as spring tides. Pumping the pool at neaps so that the full springs range is used thus allows neap tides to deliver roughly twice as much power as they would offer without pumping. So a system with pumping would show two-weekly variations in power of just a factor of 2 instead of 4.

These benchmarks – **3.3** W/m^2 without pumping and **6.3** W/m^2 with pumping – assume that power is delivered and demanded at exactly the optimal times, and that there is no limit to the flow rate of water in the system. Such a system is highly intermittent and spikey. We now examine a more reasonable, smooth, but still intermittent, benchmark.

An intermittent solution that alternates between steady pumping and steady generating

Figure 5 shows a pumping and generating schedule where the system is always active; it spends exactly half the time pumping (at constant power) and half generating (at constant power). The system alternately sucks 7 W/m^2 from the electricity grid (for three hours) and delivers 20 W/m^2 (for three hours). The net energy contribution is thus 6.5 W/m^2. The range required is about 10 m – slightly more than double the tidal range of 4 m.

Multiple-lagoon solutions

Using multiple pools – for example, a high pool and a low pool – doesn't increase the deliverable power, but does increase the flexibility of when power can be delivered, thus enhancing the value of a facility. A two-pool facility is 'always on', and would be able to provide the same sort of valuable service as the Dinorwig station.

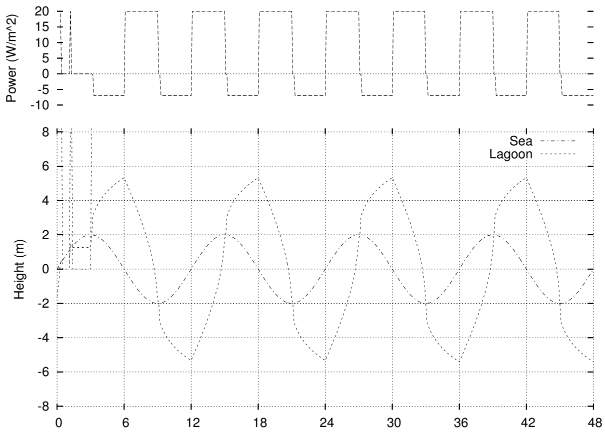


Figure 5. A bursty tidal power option using one lagoon at sea-level. The tidal range is $2h = 4\,\mathrm{m}$. The system alternately sucks $7\,\mathrm{W/m^2}$ from the electricity grid (for three hours) and delivers $20\,\mathrm{W/m^2}$ (for three hours). The net energy contribution is thus $6.5\,\mathrm{W/m^2}$.

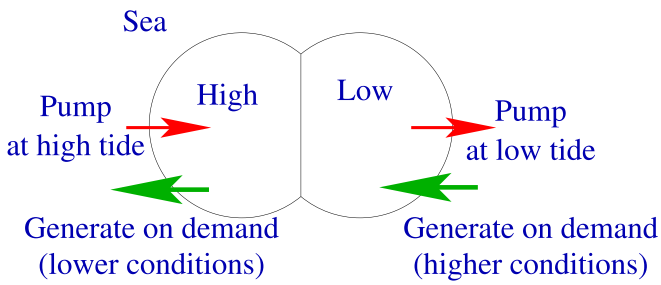


Figure 6. Design assumed: one, two, or three lagoons are located at sea-level. While one lagoon is being pumped full or pumped empty, the other lagoon may be delivering steady, demand-following power to the grid. Pumping may be powered by bursty sources such as wind, by spare power from the grid (say, in the future, from nuclear power stations), or by the facility itself, using one lagoon's power to pump the other lagoon to a greater height.

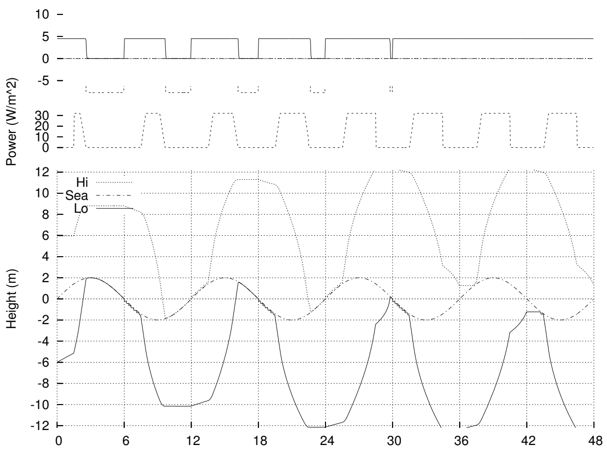


Figure 7. A two-lagoon system with no power input from the grid or wind. The tidal range is $2h = 4\,\mathrm{m}$. Self-pumping takes place with a power of $32\,\mathrm{W/m^2}$. After an initial set-up period of a couple of periods, the system delivers a steady $4.5\,\mathrm{W/m^2}$. Top graph: solid line – power delivered to grid. Second graph: self-pumping power.

A two-pool facility can do its own pumping.

Thus a tidal station can turn the intermittent tidal power into demand-following power. As an extreme simple case, let's assume that demand is absolutely steady. Not realistic, but a challenging target for a renewable source to deliver!

Figure 7 shows a possible schedule for a two-lagoon system. In contrast to the single-lagoon schedule, where pumping periods and generating periods alternate, each lasting 3 hours (with switches from pumping to generating at high tide and low tide), here generating happens all the time and pumping lasts for three hours around each high tide and three hours around each low tide. One lagoon's water level is always above sea-level; the other's is always below.

In this figure, the pumping into or out of one lagoon is entirely funded by the energy in the other lagoon. No energy is required from the grid. After an initial set-up period of a couple of periods, the system delivers a steady $4.5\,\mathrm{W/m^2}$. The range is about $25\,\mathrm{m}$ (about six times the tidal range).

The same facility can simultaneously be used for pumped storage.

For simplicity and clarity, I again assume that the demand is steady. I also assume in the computations that the power being stored is steady, but the system would work equally well if the incoming power fluctuated around its average value on a timescale of minutes or one or two hours.

Figure 8 shows the result of using the same schedule, doing self-pumping for three hours around each high and low tide, plus pumping $5.5\,\mathrm{W/m^2}$ of 'bursty' wind power into the appropriate la-

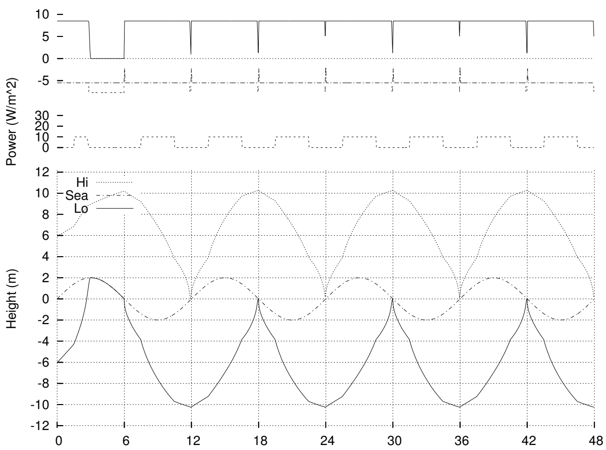


Figure 8. A two-lagoon system receiving $5.5\,\mathrm{W/m^2}$ of bursty wind power and delivering $8.5\,\mathrm{W/m^2}$ of steady power. The tidal range is $2h = 4\,\mathrm{m}$. Self-pumping takes place with a power of $10\,\mathrm{W/m^2}$.
Top graph: solid line – power delivered to grid; dashed line – average power received from intermittent source, e.g. wind. Second graph: self-pumping power.

goon all the time. The system is generating a steady $8.5\,\mathrm{W/m^2}$. The range is roughly 20 m (five times the tidal range).

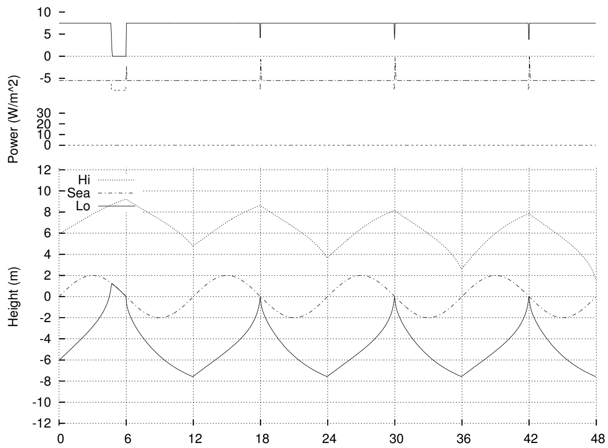
The facility could also be used for pumped storage alone.

Perhaps pumps and generators are a valuable resource and none are available for the self-pumping trick. Figure 9 shows results for two incoming power conditions. In (a), $5.5\,\mathrm{W/m^2}$ of 'bursty' wind power is turned into $7.5\,\mathrm{W/m^2}$ of steady power; the range between the high pool's maximum and the low pool's minimum is 16 m. In (b) $18\,\mathrm{W/m^2}$ of 'bursty' wind power is turned into $19\,\mathrm{W/m^2}$ of steady power; the range required is about 26 m.

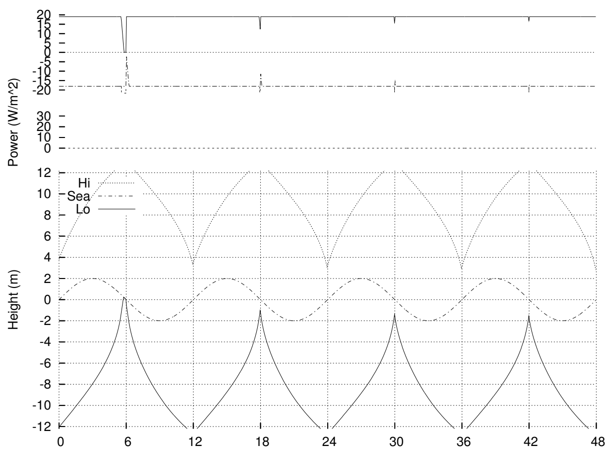
Other designs, future work

The next design I would like to explore uses three lagoons. The two-lagoon solution (self-pumping) doesn't deliver as much power per unit area, and required larger vertical amplitudes, than the one-lagoon solution with externally-funded pumping. I expect that there are various three- or four-lagoon solutions in which one or two of the lagoons follow trajectories like that of the one-lagoon solution, with most or all of the required pumping funded internally.

An obvious piece of further work is to explore the economics of realistic daily supply and demand inputs. It's possible that the economically optimal pumping and generating strategy might sometimes be to exploit just one high tide and one low tide for pumping each night, and generate at appropriately selected times in the day.



(a)



(b)

Figure 9. In these simulations, no self-pumping takes place. (a) A two-lagoon system receiving $5.5\,\mathrm{W/m^2}$ of bursty wind power and delivering $7.5\,\mathrm{W/m^2}$ of steady power. (b) A two-lagoon system receiving $18\,\mathrm{W/m^2}$ of bursty wind power and delivering $19\,\mathrm{W/m^2}$ of steady power. The tidal range is $2h = 4\,\mathrm{m}$. Top graph: solid line – power delivered to grid; dashed line – average power received from intermittent source, e.g. wind.

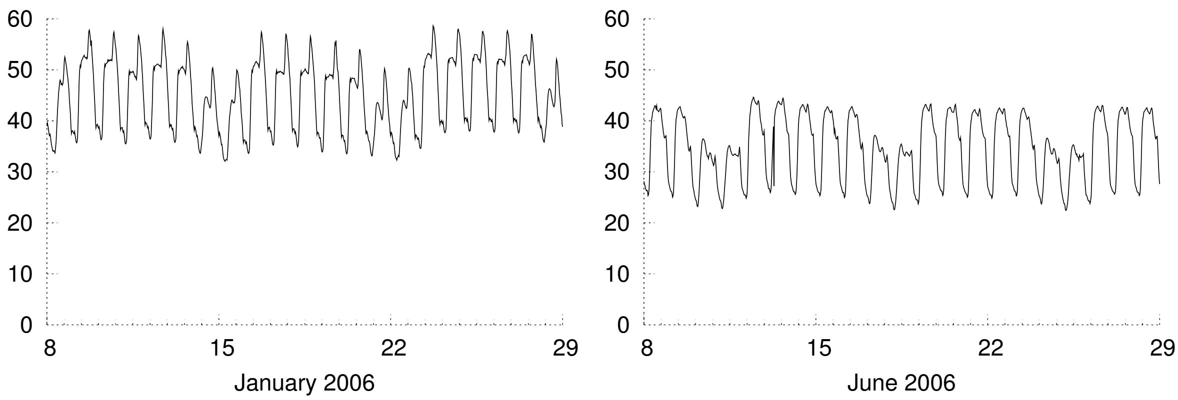


Figure 10. Electricity demand in Great Britain (in GW) during three winter weeks and three summer weeks of 2006.

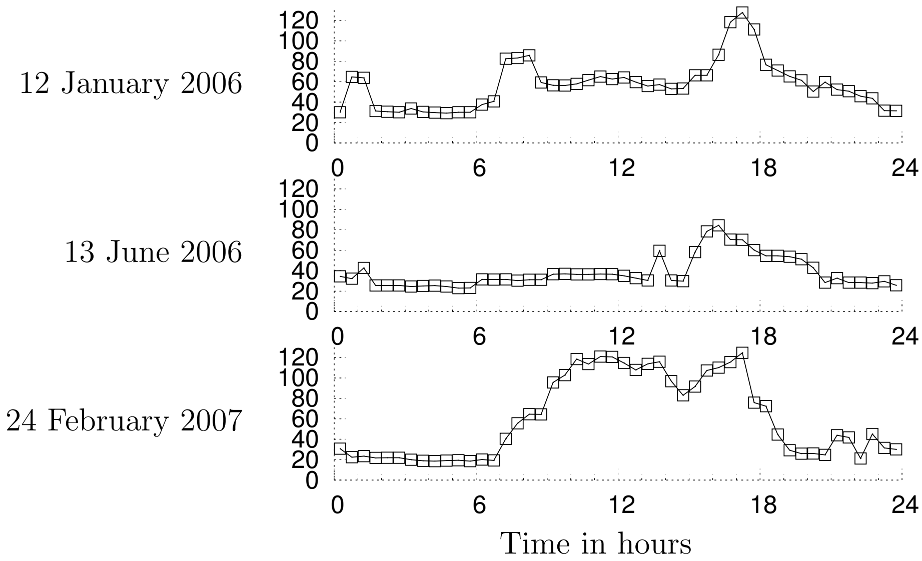


Figure 11. Electricity prices in Great Britain (in £ per MWh) on three days in 2006 and 2007.

To reduce costs associated with high walls we could look for lop-sided schedules where lagoons are pumped down to lower extremes and not pumped up so high.

Criticisms: I've ignored the true dependence of generating and pumping efficiency on head. I've assumed the sea is an inexhaustible source or sink of water at the current sea-level. Once the system reaches a sufficiently large size, its sucking and blowing will have a significant effect on local sea-level.

I've not taken account of the cost of turbines, assuming that we can install whatever pumping and generating capacity these schedules call for.

Discussion

Some of these ranges are enormous. Where could such a system be put? What would it cost, and what would it be worth?

One simple observation is that the value delivered scales as the area of the lagoons, but the dominant part of the cost – the walls – scales as the circumference. Very large systems are thus favoured by simple economics.

Let's pick a benchmark size. How about 10 km × 10 km?

- A plain old intermittent tide-pool of this size (3.3 MW/km^2) would deliver 330 MW on average (assuming, as usual, a 4 m tidal range).

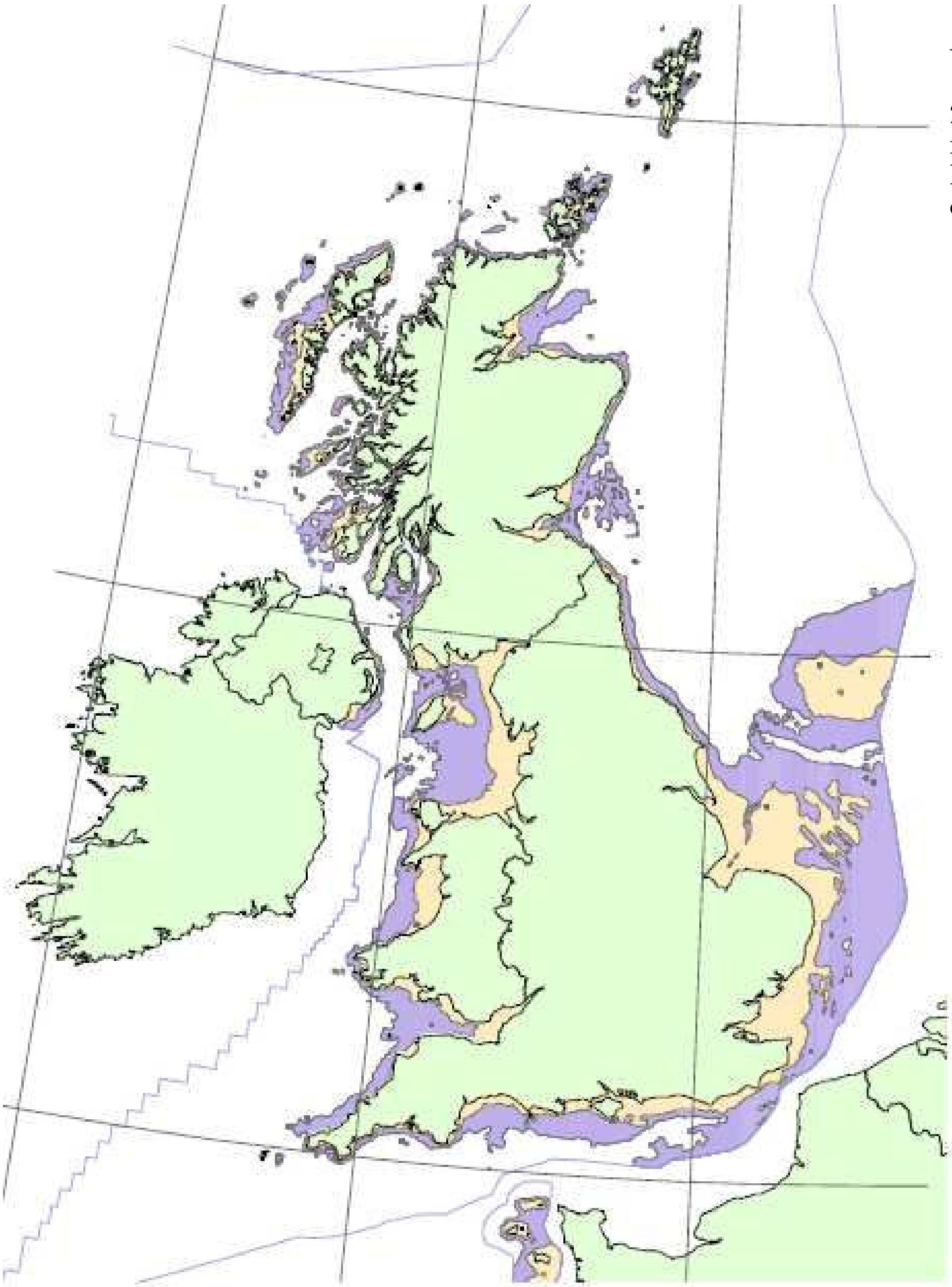


Figure 12. UK territorial waters with depth less than 25 m (yellow) and depth between 25 m and 50 m (magenta). Data from DTI Atlas of Renewable Marine Resources. © Crown copyright.

- With pumping to 5 m above and below mean sea-level, a single lagoon would deliver a net power of 650 MW.
- The two-lagoon solution that does its own pumping would deliver a **steady** 450 MW.
- It could also be used as a pumped storage system for intermittent or unwanted electricity. For example, it could turn 550 MW (average) of bursty wind power into 750 MW of steady power. (A round-trip efficiency of 135%!) Or it could turn 1.8 GW of bursty wind power into 1.9 GW of steady power. A round-trip efficiency of 105% compares favourably with Dinorwig's 75%.
- For comparison of pumped storage capacity with Dinorwig – a profitable power station with a capacity to store 9 GWh – these tide pools would have a capacity of about 20 GWh (assuming a height change of 13 m). So this facility would be worth two Dinorwigs. Indeed, it would be worth more, since it would be better than 100% efficient, in contrast to Dinorwig's 75%.

We need at least half of this water to have a depth of about 13 m below mean sea-level. There's lots of shallow water around Britain. We need the tidal range to be as large as possible, too. An ideal location might be an area of shallow sea surrounding a small island, where the pumping facilities could be built. Alternatively the high pool could be built on land. Offshore lagoons have many advantages, as advocated by Tidal Electric limited, and Friends of the Earth Friends of the Earth Cymru [2004]. I think the best two locations in the British Isles are, on the East Coast, The Wash (where the mean spring tidal range exceeds 7 m) and, on the West Coast, anywhere in the Irish Sea from the Mersey to the mouth of Morecambe Bay (where there have been proposals to build a 12-mile bridge with built-in tidal and wind power). The mean spring tidal range here is 7–8 m. Morecambe Bay already has a gas field, so there is a precedent for energy exploitation. From wikipedia: 'A lease has been granted for the development of two wind turbine sites in Morecambe Bay, one at Walney Island and the other at Cleveleys. Together these will have around 50 turbines.' The Wash would be big enough to fit one 10 km by 10 km tidal facility, but perhaps not more. The Irish sea is bigger. Both locations have a tidal range bigger than I assumed, so the potential power is bigger – perhaps about twice as big, on average.

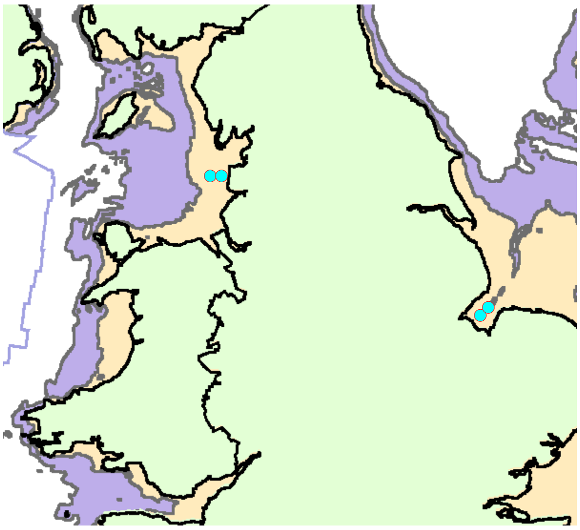


Figure 13. Two locations with plentiful shallow water and big tides: The Wash, and the Irish Sea (marked by two circles each). UK territorial waters with depth less than 25 m (yellow) and depth between 25 m and 50 m (magenta). Data from DTI Atlas of Renewable Marine Resources. © Crown copyright.

What about the cost? Two circular lagoons enclosing $100\,\text{km}^2$ would require 50 km of walls. The low pool's walls would be in water of depth about 13 m. And (for the most ambitious schedules described here) we need the high pool to have a wall of height 13 m above sea-level. Let's look at some costs from Tidal Electric limited. Their plan for a small tidal lagoon in Swansea Bay (where the mean tidal range varies between 4.1 m and 8.5 m) involved 9 km of walls and would cost either £82 million (according to Tidal Electric, AEA Technology, and W.S. Atkins Engineering) or £234 million (according to critics of Tidal Electric's scheme). The cost of the wall was estimated to be £49 million or £114 million respectively. Taking the larger of these two figures, the cost per km of wall is £13 million. This wall was of height 16 m from sea bed to crest. The walls I was imagining above would be slightly higher or perhaps twice as high (if the high pool is built in water of the same depth as the low pool). The wall, using this technology, would thus cost at least £0.65 billion. Perhaps costs could be reduced by alternative wall construction methods. And I think the wall heights could be trimmed quite a lot without spoiling the results sketched here. Doubling the wall's cost to allow for all the other stuff, I'll propose £1.3 billion as the cost for a 10 km × 10 km two-lagoon system.

Dinorwig cost £0.4 billion in 1980 money, so £1.3 billion for a facility superior to two Dinorwigs sounds a reasonable deal to me. Another way of expressing the value of the facility is to take what people currently spend on wind turbines – for example, £500 million on the '650 MW' Lewis wind farm, plus £375 million on the Lewis–Mainland electricity connection: an expenditure of about £0.9 billion on roughly 220 MW (average) of intermittent power. Scaling this up, 550 MW of bursty wind power seems to be valued at £2.25 billion. The pumped storage solution presented in figure 9(a), requiring walls of height 9 m above mean sealevel, would turn this 550 MW of bursty wind power into 750 MW of steady demand-following power. It seems plausible to me that this service would be worth the estimated cost of £1.3 billion.

If the cost needs to be reduced, we simply make the system bigger. For example, we multiply the area by four (to 20 km × 20 km) and double the length of all the walls. The estimated cost roughly doubles (to £2.6 billion, say), but the storage quadruples to 40 GWh (more than four Dinorwigs). As a source of tidal power, this quadrupled station could deliver a steady 1.8 GW all day and all night, and could serve peak demand.

Cost comparison with vanadium flow batteries

For comparison, VRB power systems have provided a 12 MWh energy storage system for the Sorne Hill windfarm in Ireland (currently '32 MW', increasing to '39 MW'). I think VRB stands for vanadium redox battery. This storage system is a big 'flow battery', a vanadium-based redox regenerative fuel cell, with a couple of tanks full of vanadium in different chemical states. This storage system can smooth the output of its windfarm on a time-scale of minutes, but the longest time for which it could deliver one third of the 'capacity' (during a lull in the wind) is one hour. The same company installed a 1.1 MWh system on Tasmania. It can deliver 200 kW for four hours, 300 kW for 5 minutes and 400 kW for 10 seconds.

A 1.5 MWh vanadium system costing $480 000 occupies 70 m^2 with a mass of 107 tonnes. Its efficiency is 70–75%, round-trip.

Scaling this up, and translating into British, a 10 GWh system using vanadium would cost £1.64 billion; a 20 GWh system would cost £3.3 billion. The tidal-pumped-storage system thus looks competitive with the storage technology currently used for large windfarms. [Scaling up the Vanadium technology to 10 or 20 GWh might have a noticeable effect on the world Vanadium market, but it is probably feasible. Current worldwide production of Vanadium is 40 000 tonnes per year. A 10 GWh system, assuming 1-molar Vanadium solution, would contain 36 000 tonnes of Vanadium – one year's worth of current production. Vanadium is currently produced as a by-product of other processes, and the total world Vanadium resource is estimated to be 63 million tonnes.]

Compressed-air storage

Compressed air storage is said to be significantly less expensive than other large-scale storage options [Denholm et al., 2005]. "Energy is stored by compressing air in an airtight underground storage cavern. To extract stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure turbine, which captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator. Turbine exhaust heat and gas burners are used to preheat cavern air entering the turbines. CAES can be considered a hybrid generation/storage system because it requires combustion in the gas turbine. The storage benefit of precompressed air is the elimination of the turbine input compressor stage, which uses approximately 60% of the mechanical energy produced by a standard combustion turbine. By utilization of precompressed air, CAES effectively "stores" the mechanical energy that would be required to turn the input compressor and uses nearly all of the turbine mechanical energy to drive the electric generator."

1 kWh of electricity generated by the CAES turbine requires 4649 kJ of fuel (1.3 kWh) plus 0.735 kWh of compressor electricity. This is said to be five times more efficient than the most efficient plain fossil combustion technology.

Further details including a life-cycle analysis are in the paper [Denholm et al., 2005].

I haven't found a figure for the cost of such a storage system.

Additional opportunities

A pair of lagoons in the sea with 13 m-high walls and electrical plumbing installed would be a good place to locate wind turbines. The turbines would be offshore, which is good, but erection and maintenance of turbines on the walls would be much easier and cheaper than for regular offshore turbines. 100 m diameter turbines (with 'capacity' 3.5 MW) could be placed every 500 m – 100 turbines in total, with a 'capacity' of 350 MW. A good combination: wind, pumped storage, and tidal energy, all enhancing each other.

Perhaps to kill four birds with one stone, we could sequester carbon too: the walls could be built out of artificial limestone, or coal!

Acknowledgements

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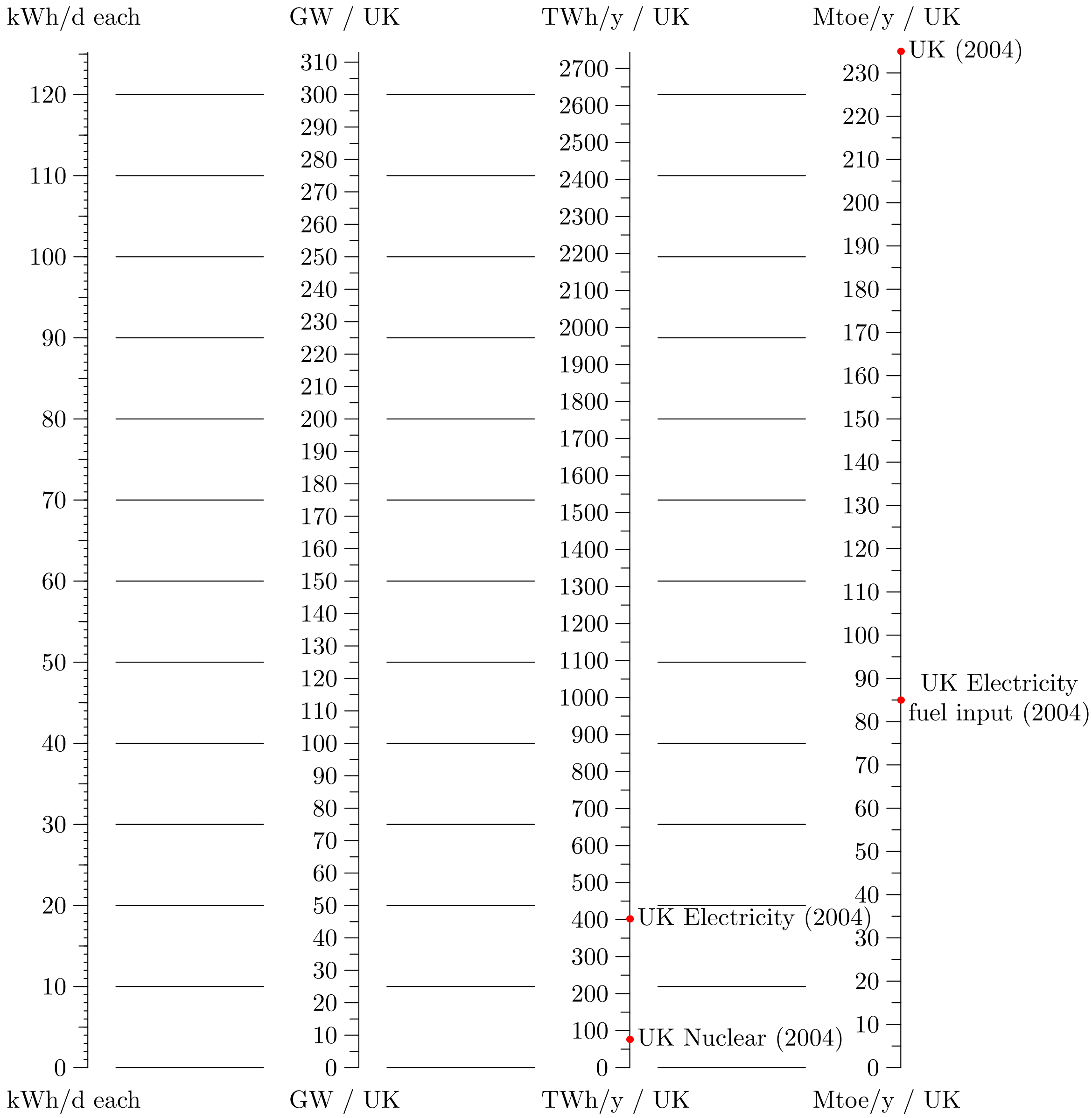
Power translation chart



1 kWh/d	the same as 1/24 kW	'UK'	= 60 million people
GW	often used for '**capacity**' (peak output)		
TWh/y	often used for average output	USA:	300 kWh/d each
1 Mtoe	'one million tonnes of oil equivalent'	Europe:	120 kWh/d each

UKERC response to the PRASEG Inquiry – Renewables and the Grid: Access and Management

January 2010

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We are funded by three research councils: the Engineering and Physical Sciences Research Council (EPSRC), the Natural Environment Research Council (NERC) and the Economic and Social Research Council (ESRC).

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UKERC Response

The UK Energy Research Centre welcomes this opportunity to provide input to the PRASEG Inquiry – Renewables and the Grid: Access and Management.

Summary

- Without the adoption of a more holistic approach that addresses BETTA structural reform and network regulation, it is difficult to see how a satisfactory resolution of the transmission access issue can be achieved.
- It is proposed that more strategic and unified development of the onshore and offshore network together with the provision of interconnection would be encouraged through common or at least zonal ownership of offshore transmission assets, while cost-effectiveness and the efficient delivery of assets could be achieved through tendering and outsourcing construction.
- Modern distribution networks are not typically designed to accommodate generation; a number of technical and operational challenges will need to be addressed in order for the connection of significant amounts of distributed generation on these networks.
- The consequences of intermittency or variability of input will need to be managed by a combination of retaining conventional plant and developing demand response. Additionally, interconnection with adjacent transmission systems and improved forecasting of wind resource and maintaining geographic diversity of wind generation could also reduce the impacts of intermittency.
- The role of "smart grids" will be to enhance the capacity and utilisation of the electricity grid (both transmission and distribution) by means other than investing in traditional transmission assets and, via the deployment of smart metering, massively increase the contribution of the demand side to system security and the decarbonisation of the heat and transport sectors.
- UKERC is concerned that a major opportunity will be missed unless there is a timely change to a regulatory regime that encourages objective and cost-efficient choices between investment and smart grid solutions.

1.Transmission: What are the challenges regarding access to transmission network for large renewables?

Concerns over transmission access arrangements have existed for some time. In fact Ofgem's predecessor, OFFER, first raised the need for reform at the time of industry privatisation in 1990, and it is surprising that the existing access arrangements, which seem so at odds with the competitive electricity energy market, have survived for so long.

The failure of the joint BERR (DECC)/OFGEM Transmission Access Review and both earlier and subsequent attempts by industry to agree an enduring access regime which is affordable, cost-reflective and capable of delivering the generation capacity required to achieve the UK's renewable obligations in a secure fashion can, arguably, be attributed to two main causes. Firstly, the reluctance of generators to relinquish what they believe to be "evergreen" transmission access rights together with the possibility of a successful legal challenge to any non-legislative attempt to dilute these rights. Secondly, structural problems associated with BETTA in pricing congestion, reinforced by current network regulation.

If there is to be a satisfactory resolution to the long standing issue of transmission access for generation, Ofgem and DECC will need to take a more holistic approach that considers the impact on transmission access of electricity market design and regulatory incentives, and not the selective and targeted approach adopted to date and which is evident from DECC's consultation on access reform, published in August 2009.

"Evergreen" transmission access rights. Existing arrangements, which allow generators ongoing access to the transmission system for the payment of a single year's use of system (TNUoS) charges with a need to give only a few months notice of relinquishing those rights, seem incompatible with the need to "share" transmission capacity in a situation where connected generation will exceed demand. The arrangements also discriminate against newly connecting generators, who are required to commit to a number of years transmission charges, and are also unhelpful in terms of identifying the need for transmission investment. Some means of addressing the issue of "evergreen" rights needs to be found if an appropriate enduring access regime is to be identified. It is therefore disappointing to note that, of the three access options proposed by DECC in their consultation on "improving Grid Access", published in August 2009, only one option involves any changes to the rights of existing generators, and that this option seems unlikely to be progressed.

Market arrangements, congestion pricing and network regulation. Existing GB electricity market arrangements result in significantly higher costs of resolving transmission congestion than those adopted in some other jurisdictions, including the previous England & Wales Electricity Pool or the old GEGB merit order process. Unnecessarily high congestion costs will discourage arrangements that allow the early connection of generation (i.e. a "socialised" connect and manage access regime) and could also make access models which target the costs of congestion on those causing that congestion prohibitively expensive for both newly connecting and existing generators behind an exporting boundary.

While Ofgem have recognised the potential difficulties that are caused by higher than necessary congestion costs, they believe that the cause is due predominately to the exercise of market power[1], rather than to the existence of any structural defect within BETTA. While the exploitation of market power may well result in the costs of resolving congestion being higher than would be the case in a truly competitive market, UKERC proposes that a more fundamental issue is the methodology used by BETTA to deal with transmission congestion.

National Grid propose to resolve transmission congestion by seeking bids and offers via the Balancing Mechanism or by striking security contracts with specific generators to reduce or increase generated output as appropriate. Generators making offers to replace constrained energy via the Balancing Mechanism or via these security contracts will have been excluded from the energy market and will therefore seek prices that recover both variable (fuel) and fixed costs. Generation bidding to reduce output will however only offer up (at best) the costs of fuel saved and, as the cost of resolving a transmission constraint is essentially the sum of the costs of constrained and replacement energy, it will include an element of fixed generation cost together with the differential fuel cost. This situation can be contrasted with that which applied under the old England & Wales Electricity Pool, where the cost of resolving congestion was essentially the difference between generator offers to run made at the day-ahead stage and, for similar technologies (i.e. coal), would typically be in the order of £1-5/MWhr. With BETTA, the costs of resolving transmission constraints can significantly exceed £100/MWhr.

Electricity market & regulatory incentives for transmission investment. In addition to discouraging efforts to allow for the early connection of generation, the unnecessarily high costs of resolving congestion, which are a feature of BETTA, also over-incentivise transmission investment. Generators are prevented from making objective decisions between the need for non-financially firm access with exposure to short-term transmission (congestion) costs, or financially firm access, where the short-term transmission costs are avoided by contributing to the long-term costs of investment. Unnecessarily high costs of resolving congestion will always make investment in infrastructure look relatively inexpensive and will result in generators opting for financially-firm access. Ultimately, however, this will lead to the inefficient utilisation of existing capacity and unnecessary transmission investment at a time when investment requirements are already at historic highs.

Current regulatory arrangements reinforce BETTA's built-in investment bias. With a Transmission Owner's income linked directly to the size of the Regulated Asset Base (RAB), there is an incentive to invest in order to increase the RAB and little or no incentive to avoid investment by releasing additional transmission capacity via operational means. In fact, existing network regulation does not consider and is unable to deal with the fundamental question of whether the level of network capacity released to network users in operational time scales is delivering good value for money to users. There are no mechanisms that provide assurances to all parties (network users, network operators and the regulator) that an appropriate balance is being struck between release of network capacity in real time and the provision of additional infrastructure. This significantly compromises the economic efficiency of system operation and represents a major barrier to the innovation necessary to enhance increase network utilisation and ensure efficient development.

i). What do you believe is the best model for the provision of access to the transmission network for large renewables, bearing in mind the various options under the 'Connect and Manage' model as laid out in the recent DECC consultation on 'Improving Grid Access'?

As indicated previously, without the adoption of a more holistic approach that addresses BETTA structural reform and network regulation, it is difficult to see how a satisfactory resolution of the transmission access issue can be achieved. A fully socialised connect & manage approach is likely to be ruled out as an enduring option due to the potentially prohibitive costs to be borne ultimately by electricity customers[1] While the "hybrid" approach apparently favoured by DECC pragmatically attempts to reduce the impact of full socialisation, it lacks rigour and patently discriminates in favour of existing generators. Conversely, access options such as Ofgem's favoured "fourth model" or National Grid's proposals for locational BUSoS charges[2], which partially address the issue of "evergreen" rights and allocates congestion costs on those generators causing the congestion, seem likely to impose costs which could seriously undermine renewable deployment in Scotland and also cause difficulties for existing Scottish generators.

However, if changes to BETTA methodology were introduced that reduced the costs of resolving congestion to the levels which would apply if mandatory pool-type arrangements applied in GB (i.e. the old E&W Electricity Pool, or market arrangement that have been adopted in New Zealand or parts of the US) then these alternatives may become more acceptable[3]. The additional costs implied by National Grid's locational BUSoS proposals set out in GB ECM18, which arguably

[1] "Enduring Transmission Access Reform". Report 70/09, Ofgem, 25 June 2009.

[2] Locational BUSoS Charging - GB ECM18, Impact Assessment and consultation". This suggests that a large (500MW) high load factor wind generator in the North of Scotland could expect to pay an additional £6.35 million per year under GB ECM18, while a similar sized conventional power station in the South of Scotland would pay an extra £11.53 million per year.

[3] An indication of the likely reduction in the costs of resolving congestion if they were defined by fuel cost differentials rather than BM bids and offers, can be gained from the report "An assessment of the potential impact on consumers of connect & manage access proposals by Frontier Economics for Ofgem, November 2009, which suggests that the use of differential fuel costs reduces total constraint costs by around two thirds. However, Prof: Strbac in his evidence to the Energy and Climate Change Committee's Report into the Future of Britain's Electricity Networks, suggested that the use of differential fuel costs to calculate the costs of resolving congestion might reduce those costs by a factor of 10.

offers the most promising combination of cost-reflectivity, simplicity and appropriate transmission investment signals, might no longer represent a significant barrier to renewable generation connecting in Scotland or pose unacceptable charges on existing Scottish generators. The same may be true of Ofgem's preferred "fourth model", however, the complexity of the auction process and discrimination between those able to take part in the initial allocation of access and those who come later, seem likely to rule this option out of contention.

ii). Offshore wind: Do you think that the present point to point plans for offshore grid connections is the best way forward for large scale offshore renewables?

The size and location of Round 1 and 2 schemes makes radial connections the most appropriate method of connecting them to the onshore grid. However, the exploitation of high resource areas such as the North Sea will require the development of much larger and remote projects as envisaged under Round 3, which will require a more strategic, networked approach to connection.

The UK seems to have adopted an offshore regulatory regime which is seems neither unnecessary for Round 1 & 2 projects, nor appropriate for Round 3 and beyond. With one possible exception, all Round 1 & 2 projects are to be connected to the onshore grid by their own, discrete, radial connections. These connections will be generation spurs that can in no meaningful way can be described as transmission. They support no demand and there is no possibility of third-party access. Consequently, it is not clear why the connections for Round 1 and 2 projects need to be regulated.

Looking forward to Round 3 and beyond, the current developer-driven approach involving the appointment of individual OFTOs for each offshore project via competitive tender will continue to produce radial connections and seems unlikely to encourage a strategic view. For offshore and onshore network development to be optimised as one, and opportunities to interconnect with adjacent electricity systems exploited, the NETSO will need to take up a strategic, coordinating and pro-active role, with some offshore transmission capacity developed on an anticipatory basis. It is not clear that the current regulatory arrangements, which aim to reduce overall costs through competitive tendering, are capable of encouraging or supporting such an approach. It is proposed that more strategic and unified development of the onshore and offshore network together with the provision of interconnection would be encouraged through common or at least zonal ownership of offshore transmission assets, while cost-effectiveness and the efficient delivery of assets could be achieved through tendering and outsourcing construction.

2. Distribution: What are the challenges facing Distribution Network Operator's in providing access to the grid for distributed generators?

i) Do you think that the existing distribution networks can cope with a large increase in distributed generation?

Although considerable amounts of generation were once connected at distribution voltage levels (132kV and below), modern distribution networks are not generally designed to accommodate generation. Unlike the transmission system, which is dependent on connected generation for security, distribution networks are passive in nature and do not require to be actively controlled. If distribution networks are in future to accommodate significant amounts of generation, which will become an integral part of their security, additional monitoring, control, and communications systems will need to be provided and Distribution Network Operators will need to develop a "system operator" capability. In addition, the connection of significant amounts of generation will require the following specific technical challenges to be addressed:

- *Fault levels.* Synchronous generation will contribute fault current in the event of a network fault and lead to a general increase in network "fault level". This will require the fault rating of distribution network equipment, and that of customer equipment connected to the distribution networks, to be increased or fault limiting devices to be installed. Induction generators, or synchronous generators connected via power electronic interfaces, contribute little fault current and this can lead to fault detection issues.
- *Protection against faults.* Currently, the use of time graded over current protection is widely used to detect distribution network faults. This will become inadequate with the connection of generation.
- *Fault ride through.* Currently, technical standards require distribution-connected generation to disconnect in the event of a network fault, in order to avoid damage to customer equipment in the event of a section of network becoming "islanded". However, once significant amounts of generation become connected, this design philosophy becomes untenable - both from a local network and "system level" point of view. Generation will need to "ride through" local network faults in order to provide local security and also survive transmission system faults in order to avoid the wholesale loss of generation at loss of security at a system level. It is worth noting that the loss of large amounts of wind and other local generation, designed to trip in the event of low frequency, was a significant feature in the widespread loss of supplies that occurred across Europe in October 2006.
- *Islanding.* As indicated above, distribution-connected generation will ultimately become an integral part of network security and need to be able to survive being disconnected from the main distribution network in order to support local demand. This implies the need to be able to operate in accordance with statutory frequency and voltage standards. A good example of this issue is West Denmark, where security problems occur once local generation output exceeds local demand in the event of interconnection to the mainland being lost. The proposed solution to this problem is "cell controllers" with black start/islanding capability.

- *Network voltage control.* Existing arrangements for the control of distribution network voltages are designed on the basis of uni-directional power flows and may not be able to handle the range of voltage variation arising from the connection of local generation. Voltage control mechanism may need to be upgraded and "on-load" transformer tap changers installed on 11kV/medium voltage transformers to accommodate local generation "hot spots".

3. Variability: How can variability of input to the grid be best managed?

The consequences of intermittency or variability of input will need to be managed by a combination of retaining conventional plant and developing demand response in order to provide capacity support and adequate reserve in operational timescales. Improved forecasting techniques and the deployment of renewable technologies whose output is more predictable would also be helpful. Increasing interconnection capacity with adjacent transmission systems will also contribute, although there is a risk that support from adjacent systems may not be available when required, if for example weather systems affect adjacent systems simultaneously. Maintaining geographic diversity of wind generation will also reduce the impacts of intermittency and the need for capacity and operation reserve, as will improvements in forecasting techniques. Utility scale storage also has the potential to reduce the requirement for backup generation capacity; however, a reduction in cost will be required before dedicated storage becomes a viable option.

As renewable deployment builds and the load factors seen by conventional plant falls, economics may begin to favour a certain capacity of low capital cost/ high variable cost plant such as OCGTs

i) In anticipation of a large increase in renewable energy generation, what do you think are the main challenges involved with backup capacity?

The utilisation of conventional plant retained for backup purposes decrease steadily as renewable deployment progresses and the greatest challenge will be that of financial viability. With the GB electricity market only rewarding energy, back up generation will be increasingly dependent on periods of high energy prices to support its fixed costs. As the incidence of these high energy price periods will vary considerably from year to year, the investment environment will become inherently more risky and financial returns will need to increase. The need to ensure sufficient investment in back up capacity may justify the introduction of some of reward for capacity or capacity obligation; neither option is free of difficulties.

ii) What do you think is the potential for interconnectors to 'balance out' intermittency?

The exploitation of areas of high renewable resource such as the North Sea and the general increase in price volatility associated with increased levels of intermittency can be expected to drive an increase in interconnector capacity. Interconnectors will provide access to adjacent markets and provide support in terms of both capacity and dealing with intermittency. However, weather systems which straddle international boundaries or difficulties in adjacent systems may on occasion limit the support which can be provided.

iii) What do you think is the likely impact of negative prices and the effect of this on pricing structures?

Negative prices, which are likely to occur during periods of high wind output coinciding with low demand and when more generation than available demand wishes to operate, could have a negative impact on the viability of high capital cost "must run" generation such as wind, nuclear and CCS. The materiality of the issue will depend on the frequency and duration of negative price periods and there seems to be some dispute about how significant the issue may become. In their report to BERR, SKM[4] suggest that, depending on the availability of interconnection with Europe and pump storage capacity, significant energy curtailment will not occur until wind deployment approaches 40GW. However, Strbac[5] (2008b) suggests that curtailment might become first become required at wind penetrations of around 16GW.

The expectation of low or negative electricity prices is likely to drive a demand response which should result in some mitigation. The experience of Demark where electric heating has been deployed to replace gas in district heating schemes during periods of low electricity prices is instructive. While the UK is not well endowed with district heating schemes, there is considerable potential for demand response from space and water heating, and, in the future, electric vehicles. In addition to demand response, the expectation of volatile electricity prices can be expected to encourage additional interconnector capacity and possibly utility-scale storage, justified on the basis of arbitrage. In addition to mitigating price volatility, all these measures will allow greater deployment and utilisation of wind and other zero and low-carbon technologies, through the manipulation of energy demand.

iv) What do you think is the relevance of BETTA to new Grid patterns? Specifically, will the bidding system to supply the grid be practicable and affordable for a grid which has variable input.

The principle concerns about existing electricity arrangements in the context of a generation portfolio that includes a significant amount of intermittent plant relate to the absence of any explicit reward for capacity, a Balancing Mechanism that inflates

[4] Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks, Report to BERR, June 2008.

[5] Integrating Wind Generation in the UK Electricity system. Presentation 2008 to the Electricity Policy Research Group, Cambridge University, May 2008.

the cost of resolving congestion and penalises energy imbalances and the general illiquidity of the electricity markets – particularly the intra-day market. However, all these issues could readily be addressed and it is not clear that moving to alternate market structures, for example where the System Operator assumes responsibility for centralised generation scheduling and dispatch, would justify the very considerable costs involved.

Capacity payments. Measures to reward generators (or demand) for contributing to capacity requirements could be readily introduced within BETTA and whilst their introduction would no doubt introduce difficulties of their own, there would be clear advantages in terms of a less risky environment for generation investment, a reduction in energy price volatility and a reduction in the costs of resolving congestion (because marginal generators would no longer be justified in recouping fixed costs when offering replacement energy via the Balancing Mechanism).

Balancing & settlement process. The issue of the dual-cash out settlement process penalising energy imbalances, and thereby discriminating against technologies such as wind that have difficulties in accurately forecasting output, could be addressed by the adoption of a single cash-out price. A clear incentive to balance would remain, due to the high cost of imbalances which were in the same direction as net market imbalance. However, the asymmetrical and penal nature of the current settlement arrangements would be removed, with individual imbalances that reduced net system imbalance being rewarded at value.

An alternative to a single cash-out price would be to allow ex-post trading whereby parties where allowed to trade out individual imbalances after the event. Concerns have been raised, however, that ex-post trading would dilute the incentive to balance and be unhelpful to the System Operator.

Market liquidity. The introduction of large amounts of intermittent generation such as wind implies a significant increase in short-term (particularly intra-day) trading to allow intermittent generators to take advantage of increasingly accurate forecasts as real time approaches. It is of some concern therefore, that the liquidity of the GB electricity market is generally poor compared with markets in other jurisdictions. Reduced liquidity has been attributed[6] to the degree of vertical integration in the GB electricity market, lack of firm reference prices, and the fact that the Balancing Mechanism and settlement process may act as a barrier to smaller or non-physical participants. Given the future importance of intra-day trading in allowing intermittent generators to balance their contractual and physical positions, the need for possible measures to improve short-term liquidity and facilitate intra-day trading need to be considered.

Other measures that could be considered in relation to energy balancing and intermittency could include advancing gate closure or changing the basis on which

[6] Liquidity in the GB wholesale energy markets. Ofgem, Ref 62/09, July 2009.

balancing costs are allocated. With gate closure 1 hour ahead of real time, the GB electricity market compares well with other European markets; however, recent data published by Elexon for a typical winter's day (see Figure 1) suggests that significant errors in forecasting total wind generation output still exist even 1 hour ahead of real time. If this be repeated with the wind capacity required to deliver the UK's renewable obligations, the correlation between wind imbalance and market length could result in significant penalties for some wind generators.

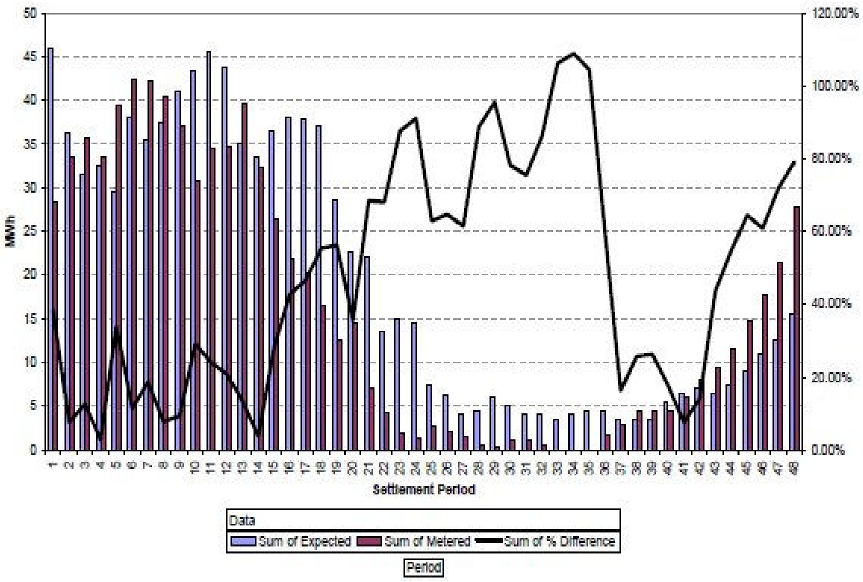

Figure 1: Comparison of 1 hour ahead forecast and actual wind output for a winter's day. Source Elexon.

Given the particular and inherent difficulties in forecasting output from wind generation compared with conventional plant, and the "special" nature of zero-carbon generation, (i.e. its role in replacing the output of fossil-fired generation) there may a case for treating wind and other intermittent technologies differently in terms of balancing requirements. While there is a need to encourage good forecasting performance, the overriding requirement to maximise wind output in the context of reducing carbon emissions suggests that any elements of the balancing and settlement regime that might encourage wind generators to reduce output in order to avoid imbalance charges should be removed.

v) What do you think will be the role of smart grids? How 'smart' will they be? How will smart meters, dynamic demand management, and financial incentives be used to deal with variable generation?

The role of "smart grids" will be to enhance the capacity and utilisation of the electricity grid (both transmission and distribution) by means other than investing in traditional transmission assets and, via the deployment of smart metering, massively increase the contribution of the demand side to system security and the decarbonisation the heat and transport sectors. Attempting the partial decarbonisation of the heat and transport sectors on a "business as usual" basis could, however, incur very significant costs[7] in terms of additional infrastructure and generation capacity requirements. The application of smart grid concepts, through the combination of energy and C & I infrastructures, offers the potential to minimise those costs through enhanced network efficiency & flexibility, customer participation and asset utilisation.

The utilisation of the *transmission system* and its capacity to accept renewable and low-carbon generation capacity through the intelligent application of operational standards and the coordinated application of intertripping and primary devices that can control power flows could be significantly increased while limiting the need for contentious and costly investment in overhead lines and cables etc.

In terms of *distribution*, techniques to increase network capability to accommodate zero- and low-carbon generation and coordinate that generation with network assets and responsive demand, offers increased local and national security and the possibility of replacing services currently provided by centralised generation. Many of the individual technical components and techniques that will contribute to the development of smart grids are already available and, in some instances, already in limited use. The challenge, therefore, is the technical and commercial integration of these techniques and technologies into the operation and management of the electricity grid.

Contribution of smart meters, dynamic demand management and financial incentives to accommodating variable generation. Through the application of smart metering and smart appliances, the demand side will contribute to reducing generation back-up capacity and the magnitude of operational reserves required. Dynamic (frequency sensitive) demand technologies will enhance the "stiffness" of the system response to frequency changes, thereby allowing the more efficient utilisation of reserves held on conventional plant. In addition, smart metering offers the potential to massively increase demand side contribution to grid system security and the enhanced deployment of renewable generation through partial the decarbonisation of the heat and transport sectors. Smart metering also opens up the possibility of offering consumers financial incentives to supply services to the electricity grid.

In addition, smart metering will;

- Allow a move to time related energy pricing
- Provide consumers and suppliers with detailed consumption (and generation) data
- Provide real time measurement of active & reactive power, current, voltage and frequency.

[7] See "Smart Grids and electric vehicles transport". Presentation to IET by Prof G Strbac, Birmingham 22 October 2009.

- Allow DNO/supplier control of consumer demand (and generation)

4. What other issues regarding access to and management of the transmission and distribution networks do you think will need to be addressed to ensure the UK meets or exceeds its renewable energy & climate change targets?

Current network regulation represents a barrier to the development of smart grid concepts and technologies and therefore to the enhanced utilisation of the electricity transmission and distribution network infrastructures. The key concern is that network regulation, by heavily incentivising investment over operational alternatives, will effectively prevent Smart Grid concepts and technologies (i.e. 'non-network' solutions) from providing an economically efficient alternative to the conventional network asset based solutions. Given the immediate need to release additional transmission capacity to accommodate renewable generation, we are concerned that a major opportunity will be missed unless there is a timely change to a regulatory regime that encourages objective and cost-efficient choices between investment and smart grid solutions.