Interconnector policy review: Working Paper 2 – Socio-economic modelling

Question 1: Do you agree with the approach we have taken to workstream 2?

Not really. The methodology adopted essentially assumes that interconnectors are the only solution and fails to look at many of the hazards or scenario corner points and their implications. There is a presumption that capacity will be built somewhere in order to feed supply via interconnectors to meet demand, and there is no attempt to look at actual market behaviour and understand how subsidy mechanisms interact with counterparty behaviour. There is no consideration of issues such as security of supply. With the French having openly threatened to cut off power supply to Jersey, and in due course to the UK over fishing rights, and with the UK excluded from EU wide agreements such as full market coupling for interconnector scheduling, it is clear that we can no longer assume that we are in a friendly international environment.

Question 2: What are your views on the scenarios, assumptions and methodology that AFRY has used to model notional future interconnectors and the impact of cross-border interconnector flows?

The use of National Grid scenarios only really has the advantage of consistency with other work. However, they were heavily criticised by people in the industry, as this polite summary demonstrates:

https://www.nationalgrideso.com/document/177781/download

Failure to take account of those and other criticisms somewhat undermines the validity of the choice. Of course, you do have to start somewhere. Scenarios for the Continent need to look at the likelihood that closure programmes for nuclear and coal capacity will run well ahead of building adequate additional dispatchable capacity. Already Denmark is not able to generate sufficient power to meet its own demand on an annual basis, although its peak wind output matches its peak hourly demand (though not at the same time). What happens in situations of shortage during protracted periods of *Dunkelflaute* needs rather more attention than it has received: 2021 weather patterns should be analysed. The possibilities include massive bidding wars, closure of interconnectors or grid ties to preserve local supply, or bidding power away from a domestic market while imposing blackouts on it, enabled by interconnectors. If you open an interconnector, you import the problems of the markets at the other end of the line.

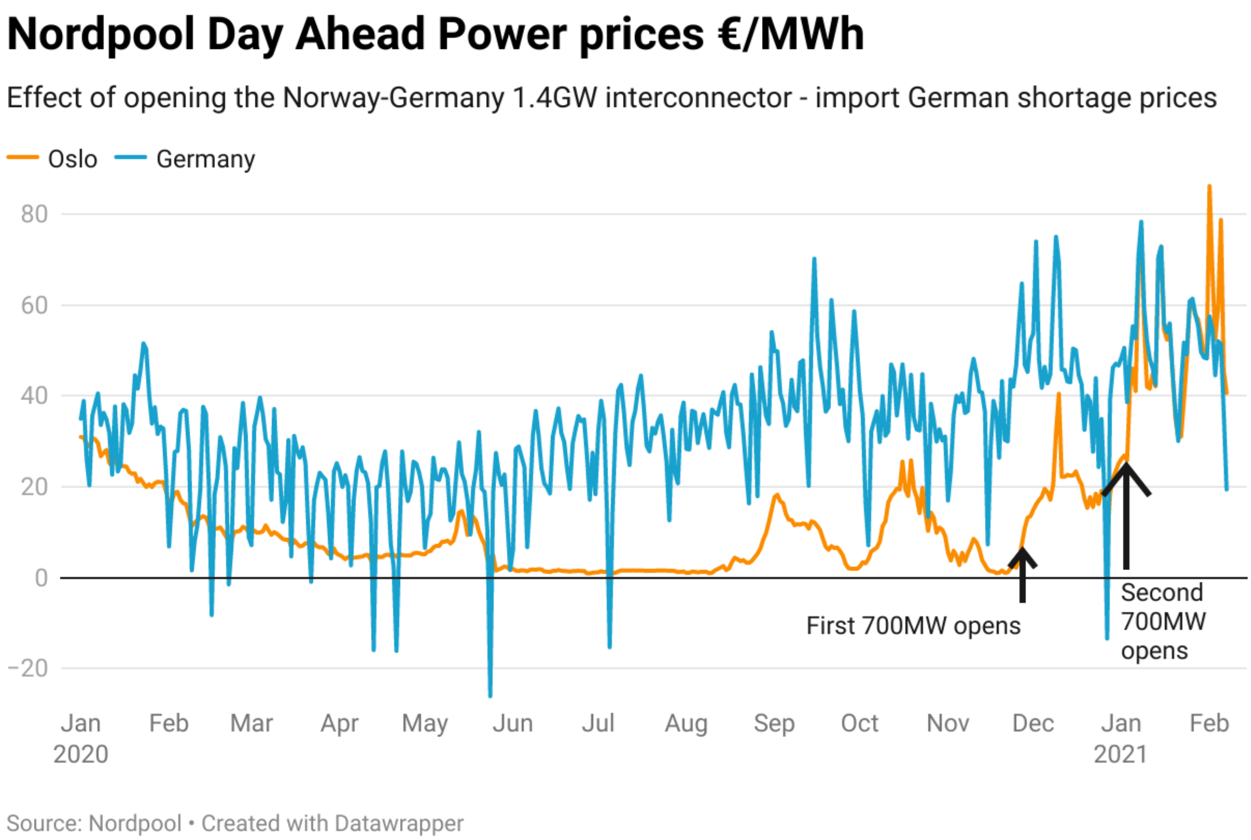
The methodology starts by looking at the benefit of adding interconnectors, rather than comparing this with the benefit of reducing the need for interconnection by investing in local dispatchable capacity. The point is that interconnector imports rely to a large extent on there being a surplus dispatchable capacity elsewhere, which must be paid for, along with the interconnector. We could save the interconnector cost and build the capacity locally, additionally reducing the need for intermittent capacity. Pretending that dispatchable capacity is 100% zero carbon if it is at the other end of an interconnector (like the originally entirely coal fired MPP3 at the Dutch end of the BritNed – it would have been much cheaper to build at Kingsnorth and forget the interconnector) may look like good politics, but it is bad economics. Whilst the methodology looks at interconnectors, it is unclear whether it adequately provides for additional grid capacity to deliver power to and from the interconnectors which is part of the added cost of remote location for dispatchable capacity: simple example – if MPP3 had been built in say Köln rather than Rotterdam there would need to be an additional 1GW of transmission between the two to get to the BritNed in the first place. Equally, supplying France with surplus offshore wind generation would entail substantial added grid capacity to deliver it on top of meeting demand along the South Coast. Not including these grid costs overstates the benefit of an interconnector project.

The methodology quoted for deriving hourly demand forecasts is to use historic profiles as the basis, scaled for overall annual demand. This seems unrealistic when you are looking at a substantial move towards electric heating with its highly seasonal and extremely peaky demand, and significant additional demand from EVs which will clearly not match historical hourly demand profiles. In consequence, peak winter demands are likely to be significantly understated, and low overnight demands are likely understated. The change in diurnal patterns will affect likely interconnector flows significantly.

Experience of trying to use weather data and theoretical performance curves from manufacturers of generating equipment is that it is not always reliable. Perhaps there is a need to look at actual performance and understand the modelling gaps. The work of Staffell & Pfenniger is a starting point.

Looking at actual experience in the UK in 2020, there were periods of low demand and high wind output that led to combinations of curtailment and export, at times even at negative prices as measured by the System Buy/Sell Price and even the Intermittent Market Reference Price (Prices for periods either side of and during negative IMRP pricing in the course of 2020 are included as an appendix). It is clear that generation benefiting from guaranteed ROC (and REGO) income per MWh generated expects compensation at least up to the value of ROCs lost if they curtail, which can set the effective export value alternative as the negative of the curtailment cost. For intermittent CFD generators, negative prices initially simply cap their CFD income to the CFD indexed strike price, and they have no incentive to curtail at all. Only when the duration of negative prices exceeds six contiguous hours or more does their CFD income suddenly fall to zero for the duration, which provides an incentive for curtailment rather than paying to generate. In practice, it seems that the system is gamed somewhat, with pricing bids ensuring a zero or marginal positive price to limit durations of contiguous negative prices, so that the CFDs pay out the full strike price throughout the event and there is no incentive to curtail unless negative price exceeds the CFD value (which is extremely unlikely for any currently operating wind farm). Proposals to amend CFD terms in future rounds to offer no payout whenever prices are negative will mean that these new windfarms will be the first in line to curtail, despite having the lowest CFD strike prices while the most expensive continue producing: it will also mean that bidders will factor in some expectation of the proportion of output that will be curtailed into their strike price bids. This is the reverse of the normal order of merit for dispatch. The result is that consumers are subsidising exports at negative prices and the balance of payments deficit is increased by the negative value exports – in contrast with pumped storage, where the benefit of negative prices is kept within GB when used for pumping. Moreover, there is an incentive for wind farms to over-invest in capacity, because they gain an outlet subsidised by GB consumers even though the economic return is negative. Without the interconnector the investment would probably not be made in marginal wind farms. Without the interconnector the GB consumer would be spared the cost of subsidising the most expensive wind farms more frequently.

Related to this is consideration of MPIs. These can be thought of as providing an option to connected windfarms to deliver to alternative markets on an arbitrage basis within the capacity limits of the connections in each direction, while getting some of the connection capacity subsidised by use as a normal interconnector at times when the wind farms are producing little or nothing. Clearly there are advantages to such schemes, certainly in comparison with landing power ashore and finding grid capacity to deliver it to an export interconnector with spare capacity. But there are clear complications in terms of subsidies (or even premia over CFD strike prices) for the attached wind farms, and who gets to pay them versus who gets to benefit from their output. This is another version of the problem of subsidising exports. We have already seen Kent acting as an MPI in bridging between NEMO and IFA1 – perhaps surprising given direct connections between Northern France and Belgium, and likewise for the Irish interconnectors which usually operate in the opposite direction to the others, with GB acting as a transit station. The Norwegian market will increasingly be dominated by interconnector arbitrage. It is interesting that Norway has signalled some reluctance to expand interconnector capacity to the UK. The fear is that prices will be bid up, suddenly making heating a very expensive proposition during periods of winter *Dunkelflaute* for Norwegians used to very low cost hydro power. There was a dramatic linkage of prices as the new interconnector to Germany opened up over the New Year.



There are also limits to the amount of cheap power that Norway can buffer by importing and not running their hydro plant. 2020 saw water levels stay at uncomfortably high levels because they had insufficient demand and export capacity due to interconnector failures to Denmark and onward to the Netherlands and Germany. Norway may not welcome more surplus power from the Northern North Sea either. Social economics and hard engineering can interfere with economic calculation.

There seems to be an expectation that electricity prices will fall simply because marginal costs of renewables can be low. That is unlikely to be the case in reality, because a renewables dominated system must invest in massive excess nominal capacity, very substantial backup capacity (not far short of peak demand in practice), a huge expansion in grid capacity, extra ancillary capabilities, and potentially extremely expensive methods of storage – and still be faced with rising curtailment. It is hard to imagine such a system being even marginally profitable without prices on average being sufficient to cover all the costs. What we can expect is radical increases in price volatility to the extent that some markets continue to function rather than being replaced with operation by rulebook. The examples of CAISO, which is heavily dependent on interties, yet regularly faces rising blackouts (which will only worsen when the Diablo Canyon nuclear plant shuts down), and Texas (where dispatchable capacity was unable to cope with demand in cold or hot windless weather, and where intertie supply to ERCOT dropped from 1.2 GW at the time of the main capacity trips – 1:52 a.m. on 15th February to as little as 123MW while they still were suffering major generation outages in the subsequent days), provide examples of the limits of interconnection as a solution to extreme demand when your neighbours also have the same problem, and when remuneration has been insufficient to ensure adequate dispatchable capacity. The reality is that getting much beyond a 60% level of annual renewables penetration is going to come at rapidly rising cost.

Question 3: Do you agree with our view on the results of AFRY's modelling? Do you agree that this modelling supports the needs case for further interconnection?

AFRY's modelling show that extra interconnectors are a disbenefit to GB consumers and GB as a whole. By the time you add in the effects of other issues not covered in their analysis, the outcome is likely to be substantially worse. It is even dubious whether the projects have a positive value to the connected countries. So it does not justify further investment at all. It justifies a re-think.

Question 4: Is there any further information or additional studies that you think should be factored into our analysis?

Please include the ideas from this response into your thinking. You may wish to commission more detailed study of some of the issues raised.

Critique of FES 2020

Some highlights:

> A strong area of agreement amongst the respondents was that policy needs to be put in place as soon as possible in order to support the deployment of fuel switching technologies. Due to investment cycles, many stakeholders believe that a policy framework must be put in place during the early 2020s. There is currently little incentive for companies to invest in these expensive technologies. Such policy may include targeted funding for sectors, for example mirroring the Clean Steel Fund, or increasing carbon taxes. Stakeholders also stressed the importance of policy targeted to increase investment in carbon capture and hydrogen technology. While many see the potential for a green recovery, others worry whether the coronavirus pandemic will delay investment in such technology.

More subsidies and regulatory fixes please! Carbon taxes to force up market prices for power!

> Most respondents thought that heat pumps would be unable to meet peak heat demand on their own and that significant insulation (similar to Nordic countries) or some form of backup heating would be needed to meet peak heat. All respondents thought that heat pumps would not be able to meet hot water demand on their own and some form of hot water creation system would be needed. There was a range of views on our insulation assumptions, with some saying that high levels were desirable and others that to get to high efficiency levels would be extremely disruptive. Government policy is seen as key in this area.

Have they read Prof Kelly's assessment that this is perhaps a £2 trillion item? Or real world research that tells us unsurprisingly that manufacturer claims about the effectiveness of heat pumps are rarely met, with a COP between 2 and 3 (rarely at the high end) being a typical average?

> The Energy Saving Trust carried out on site testing of 83 heat pumps, published in the report "Getting warmer: a field trial of heat pumps". This showed for air source heat pumps the 'mid-range' of measured SPFs was near 2.2 and the highest figures in excess of 3.0. The test also included ground source heat pumps, which has slightly higher measured system efficiencies than the air source heat pumps. The 'mid-range' ground source system efficiencies were between 2.3 and 2.5, with the highest figures above 3.0.

Back to FES:

> One respondent noted that the modelling underestimated the energy required for EVs, noting evidence showed EVs currently use more energy than our sources showed. There were two strongly opposing comments on our Vehicle to Grid (V2G) modelling approach. One view being that evidence shows consumers become used to such technology, will adopt to it easily and we should be showing a higher take-up. Another being that consumers would not waste their money on V2G and so our analysis was irrelevant.

Perhaps they should be looking at battery degradation costs?

> Several stakeholders do not expect a hydrogen economy to develop successfully with the production technology and scale of production expected to not develop quickly enough.

> The biggest barrier for hydrogen storage identified by stakeholders is cost. This was closely followed by the safety regulations required for storage and whether the general public will accept it as safe. Stakeholders also identified the need for a solid regulatory framework and clear rules of ownership, access etc. for sites.

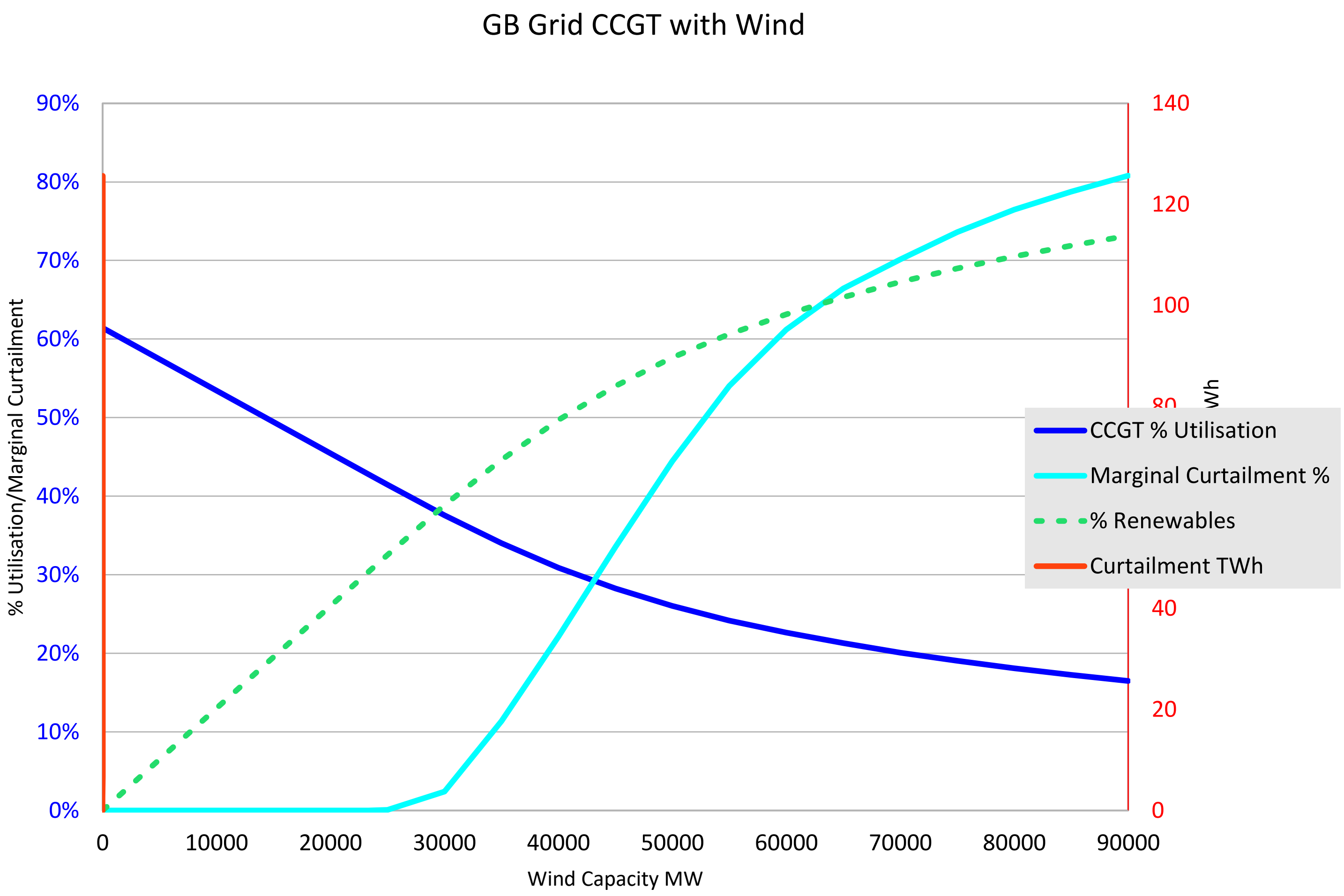
That is perhaps hardly surprising given that green hydrogen made by renewables supplying electrolysis is about ten times the cost of natural gas at Henry Hub, and blue hydrogen, made by steam reforming methane – which produces CO_2 as a by-product – is around 5 times the cost, based on estimates from Timera.

> Many stakeholders expressed concerns over the rising energy prices in the UK. The UK has set more ambitious climate change targets compared to other countries and therefore most stakeholders believed that it is unreasonable to assume that there is no carbon price differential across countries. Some would prefer to see some degree of offshoring in the scenarios to reflect the difficulty of UK industry to remain internationally competitive while supporting decarbonisation. Others would prefer to see policies included in the scenarios which help to ensure industry can remain competitive, such as carbon border adjustments or higher taxes on shipping. Stakeholders also voiced their concerns that the effects of COVID-19 have the potential to accelerate offshoring of industry and some companies may chose not to restart production in the UK.

Yes, it's going to hit industry really hard. More offshoring and loss of jobs. Fewer exports. Worse balance of payments as we import more (at least until we run out of credit).

Wind Surpluses

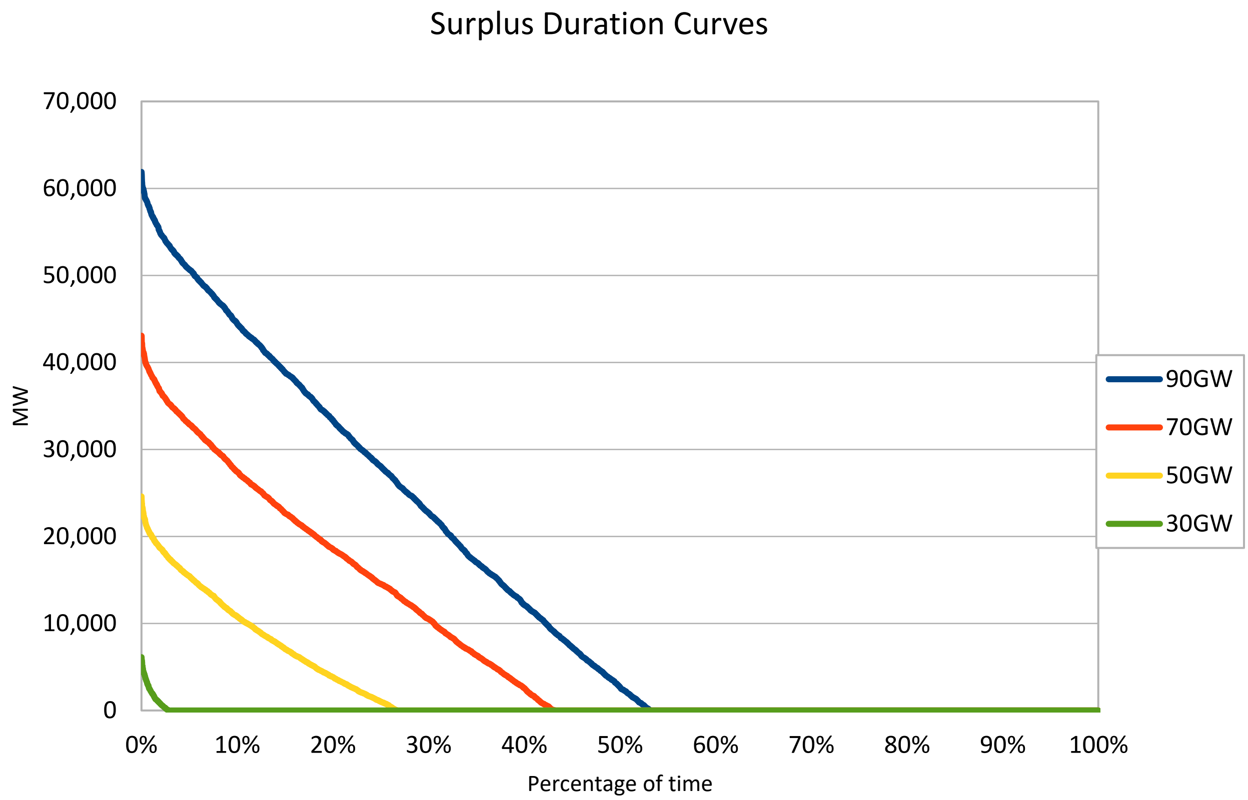
It is useful to have an underlying appreciation of simple ideas to calibrate expectations and help ensure that analysis proceeds on a rigorous basis. The following chart is based on hourly GB demand over the course of a year, and considers a flexible dispatchable "CCGT" source of generation sized to meet peak demand, with generation displaced by rising installed wind capacity, simply scaled up in proportion from actual production data. Until wind generation starts to exceed minimum demand levels it displaces gas MWh for MWh. However, beyond that point it has to be curtailed at the margin when it exceeds demand. As capacity rises, there are more and more hours where curtailment occurs, and the volume of curtailment for windy low demand hours increases. The proportion of useful output from incremental capacity falls, and overall curtailment rises initially quadratically. The effective cost of useful incremental wind output rises as it only earns an income when it is not curtailed. At 90GW of wind capacity, marginal curtailment reaches 80% of potential output, so the effective cost of the useful 20% becomes 5 times as great as the basic LCOE for an unconstrained plant. A wind farm with an unconstrained LCOE of say £40/MWh suddenly has an economic cost of £200/MWh for its useful output. Yet still over 90% of the gas generation is



needed to meet peak demand, and the proportion of demand satisfied by wind has not attained 75%.

Of course, the curtailed power could alternatively be exported if there is a market for it and sufficient capacity to deliver within the grid and interconnectors, or diverted to storage again assuming sufficient capacity to deliver and store. Any income from such disposals can then reduce the income that has to be recovered from supply that meets demand directly. There is no free lunch for surplus power – its cost must recovered.

In assessing alternative uses for surpluses it is useful to consider their duration curves – the proportion of the time that they exceed a given level. Sample curves for different wind capacities from this simple model are shown in the following chart.



Clearly it makes little sense to provide large capacity investments in interconnectors, storage systems and grid capacity for the higher levels of surplus that occur relatively rarely, which means that the economic choice will always entail a degree of curtailment. Moreover, large surpluses would almost certainly entail negative export prices in order to pay for the costs of disruption of neighbouring grids, even if they were not blocked altogether. See some of the difficulties that Germany encounters in trying to use neighbouring grids to transport its local surpluses of wind from North to South, or solar in the reverse direction, where some have even installed blocking phase shift transformers.

Storage economics depend mainly on the cost of the facilities, round trip efficiency, the margin between the cost of fill and the proceeds of discharge, and the frequency with which the capacity is turned over. A grid battery may turn over twice a day or more in terms of the total charge stored, with the range between maximum charge and discharge levels being a reasonable proportion of a short duration capacity relative to maximum input and output. Dinorwig turns over slightly less, but allowing for its black start reserve which is paid for separately, it manages roughly a daily storage turn. Going beyond daily turns to cover much less frequent events – a run of unfavourable weather, or seasonal imbalances and the economics become 1-4 orders of magnitude more difficult. Seasons occur every 365 days. We have to go back a decade for a year as poor for wind as 2021 so far. The quantities required can become overwhelming: wind output fell by over 5TWh in Q1 2021 compared with Q1 2020 – not something that can be made up for with grid batteries, or even 550 Dinorwigs at remotely economic cost. Multiply by 4 for a grid with 100GW of wind.

Storage competes with interconnectors for surplus power – potentially damaging the economics of each other because they have to share the availability. However, it should be clear that economics favours having dispatchable capacity over storage of more than modest duration, and the issue becomes where do you locate it – at home, or abroad with added costs of access and reduced security of supply.

Negative IMRP periods during 2020 from EMR Settlements Ltd.

Settlement Date	Period	Price
16/02/2020	1	8.90
16/02/2020	2	5.64
16/02/2020	3	-0.18
16/02/2020	4	-4.33
16/02/2020	5	-4.21
16/02/2020	6	-1.11
16/02/2020	7	5.00
16/02/2020	8	7.91
16/02/2020	9	18.20
05/04/2020	4	7.38
05/04/2020	5	4.53
05/04/2020	6	4.76
05/04/2020	7	4.74
05/04/2020	8	7.26
05/04/2020	9	5.21
05/04/2020	10	4.12
05/04/2020	11	1.93
05/04/2020	12	0.02
05/04/2020	13	-0.02
05/04/2020	14	-9.28
05/04/2020	15	-19.00
05/04/2020	16	-4.35
05/04/2020	17	4.04
05/04/2020	18	13.97
05/04/2020	19	18.27
05/04/2020	20	27.00
12/04/2020	23	7.02
12/04/2020	24	8.83
13/04/2020	1	0.06
13/04/2020	2	1.46
13/04/2020	3	0.65
13/04/2020	4	0.02
13/04/2020	5	-0.08
13/04/2020	6	-2.00
13/04/2020	7	-4.29
13/04/2020	8	-5.30
13/04/2020	9	-3.29
13/04/2020	10	1.99
13/04/2020	11	14.70
13/04/2020	12	17.57

20/04/2020	10	21.99
20/04/2020	11	6.15
20/04/2020	12	4.05
20/04/2020	13	1.99
20/04/2020	14	-5.04
20/04/2020	15	-10.99
20/04/2020	16	-10.03
20/04/2020	17	3.57
20/04/2020	18	18.34
21/04/2020	10	5.00
21/04/2020	11	0.00
21/04/2020	12	0.01
21/04/2020	13	-0.83
21/04/2020	14	-3.40
21/04/2020	15	-7.20
21/04/2020	16	-0.08
21/04/2020	17	1.99
21/04/2020	18	20.00
10/05/2020	23	9.06
10/05/2020	24	4.94
11/05/2020	1	1.72
11/05/2020	2	0.11
11/05/2020	3	-0.01
11/05/2020	4	-2.00
11/05/2020	5	-0.02
11/05/2020	6	0.04
11/05/2020	7	14.38
22/05/2020	13	12.68
22/05/2020	14	2.00
22/05/2020	15	-0.04
22/05/2020	16	-4.55
22/05/2020	17	5.42
22/05/2020	18	16.45
22/05/2020	19	20.23
22/05/2020	20	19.82
22/05/2020	21	18.88
22/05/2020	22	20.00
22/05/2020	23	17.89
22/05/2020	24	9.90
23/05/2020	1	-0.01
23/05/2020	2	-9.19
23/05/2020	3	-20.00
23/05/2020	4	-26.05
23/05/2020	5	-34.93
23/05/2020	6	-36.60

23/05/2020	7	-28.60
23/05/2020	8	-17.37
23/05/2020	9	-4.37
23/05/2020	10	-0.01
23/05/2020	11	-2.10
23/05/2020	12	-17.15
23/05/2020	13	-10.90
23/05/2020	14	-28.80
23/05/2020	15	-34.00
23/05/2020	16	-38.80
23/05/2020	17	-10.50
23/05/2020	18	6.95
23/05/2020	19	10.67
23/05/2020	20	11.90
23/05/2020	21	12.00
23/05/2020	22	12.73
23/05/2020	23	12.20
23/05/2020	24	0.02
24/05/2020	1	-1.24
24/05/2020	2	-5.87
24/05/2020	3	-14.84
24/05/2020	4	-17.06
24/05/2020	5	-20.00
24/05/2020	6	-24.56
24/05/2020	7	-21.77
24/05/2020	8	-23.92
24/05/2020	9	-25.43
24/05/2020	10	-19.38
24/05/2020	11	-0.01
24/05/2020	12	0.00
24/05/2020	13	0.00
24/05/2020	14	-2.17
24/05/2020	15	-4.00
24/05/2020	16	0.87
24/05/2020	17	21.50
24/05/2020	18	33.60
24/05/2020	19	43.22

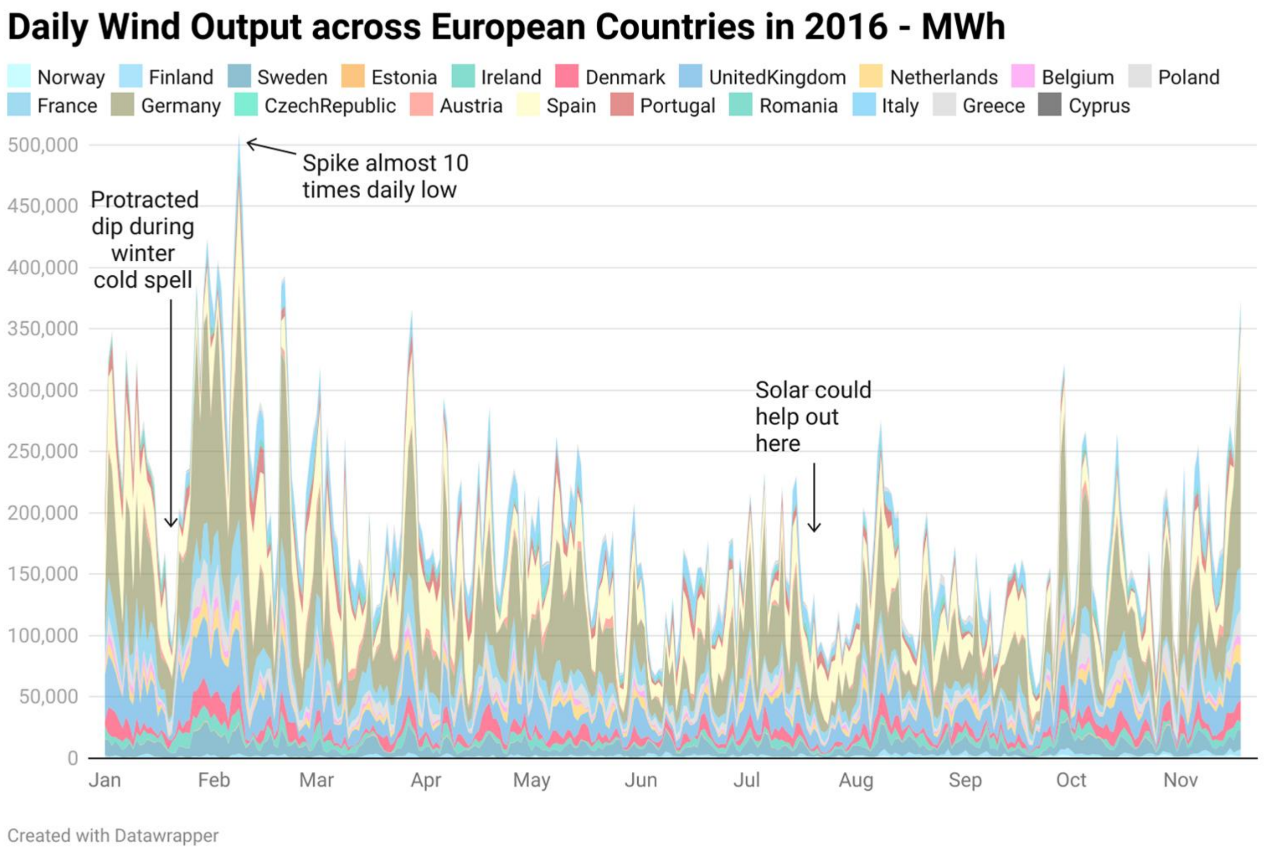
28/06/2020	2	14.88
28/06/2020	3	12.50
28/06/2020	4	0.00
28/06/2020	5	-9.50
28/06/2020	6	-15.06
28/06/2020	7	-10.90
28/06/2020	8	-0.03
28/06/2020	9	10.94
28/06/2020	10	12.40
28/06/2020	11	14.04
28/06/2020	12	9.64
28/06/2020	13	1.32
28/06/2020	14	0.00

28/06/2020	15	-2.67
28/06/2020	16	1.94
28/06/2020	17	14.92
29/06/2020	1	15.32
29/06/2020	2	9.50
29/06/2020	3	-1.70
29/06/2020	4	-14.00
29/06/2020	5	-17.65
29/06/2020	6	-2.00
29/06/2020	7	28.40
05/07/2020	1	13.06
05/07/2020	2	0.07
05/07/2020	3	-0.04
05/07/2020	4	-3.36
05/07/2020	5	-11.90
05/07/2020	6	-13.13
05/07/2020	7	-11.85
05/07/2020	8	-14.49
05/07/2020	9	-13.47
05/07/2020	10	-5.10
05/07/2020	11	-0.01
05/07/2020	12	0.02
05/07/2020	13	0.04
05/07/2020	14	-7.90
05/07/2020	15	-16.89
05/07/2020	16	-11.69
05/07/2020	17	-4.65
05/07/2020	18	18.28
05/07/2020	19	23.28
05/07/2020	24	15.00
06/07/2020	1	0.04
06/07/2020	2	0.00
06/07/2020	3	-0.71
06/07/2020	4	-0.08
06/07/2020	5	-0.90
06/07/2020	6	10.01
06/07/2020	7	24.83
24/10/2020	24	9.29
25/10/2020	1	5.12
25/10/2020	2	0.14
25/10/2020	3	0.08
25/10/2020	4	-0.09
25/10/2020	5	-7.18
25/10/2020	6	-1.02

25/10/2020	7	0.09
25/10/2020	8	4.65
25/10/2020	9	12.11
01/11/2020	24	11.00
02/11/2020	1	6.30
02/11/2020	2	3.72
02/11/2020	3	0.00
02/11/2020	4	-1.22
02/11/2020	5	0.11
02/11/2020	6	22.93
26/12/2020	23	22.60
26/12/2020	24	2.74
27/12/2020	1	4.70
27/12/2020	2	2.13
27/12/2020	3	-1.04
27/12/2020	4	-8.28
27/12/2020	5	-3.08
27/12/2020	6	-0.08
27/12/2020	7	3.95
27/12/2020	8	8.22
27/12/2020	9	22.51

Wind Correlation with Europe

The following gives some insight into the risks of assuming that "the wind is always blowing somewhere".



Far from the most difficult year, there are extended periods of *Dunkelflaute* during cold weather. The extent of problems is partly disguised by looking at daily data, but this does illustrate the limited extent to which diurnal storage or temporary demand side response solutions can help. At the same time, there is potential for considerable curtailment. Indeed, as these are actual data, they mask curtailment that actually occurred. As capacity increases, these problems are only going to get worse.

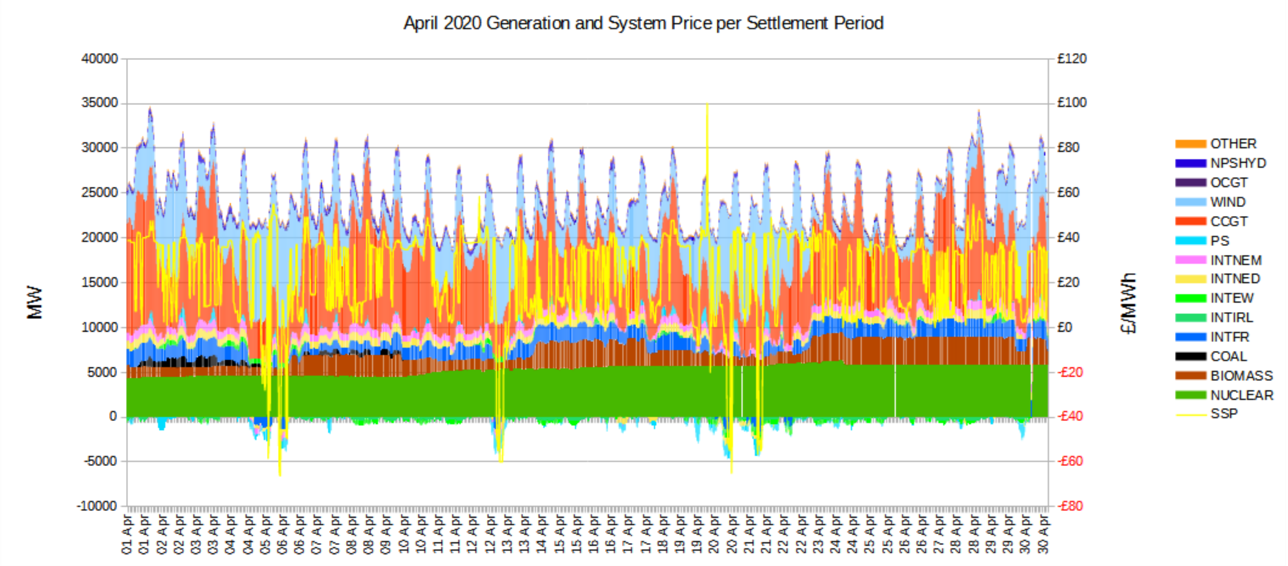
Another look at the same data in the form of a heatmap of the correlations:

	FI	SE	EE	IR	DK	UK	NL	BE	PL	FR	DE	CZ	AT	ES	PO	RO	IT	GR	CY
Finland	1.00	0.58	0.44	0.17	0.20	0.20	0.25	0.23	0.17	0.20	0.26	0.17	-0.02	-0.04	-0.03	0.05	-0.05	-0.01	-0.04
Sweden	0.58	1.00	0.59	0.29	0.67	0.38	0.43	0.37	0.57	0.30	0.55	0.40	0.07	-0.06	-0.01	0.10	-0.04	-0.07	-0.01
Estonia	0.44	0.59	1.00	0.11	0.35	0.15	0.21	0.16	0.39	0.12	0.33	0.30	0.04	-0.04	0.02	0.08	0.00	-0.06	-0.09
Ireland	0.17	0.29	0.11	1.00	0.31	0.77	0.43	0.49	0.25	0.41	0.38	0.26	0.14	0.08	0.10	0.05	0.02	-0.04	0.08
Denmark	0.20	0.67	0.35	0.31	1.00	0.50	0.59	0.45	0.65	0.35	0.73	0.44	0.07	0.07	0.12	0.10	0.00	-0.12	0.00
UK	0.20	0.38	0.15	0.77	0.50	1.00	0.69	0.73	0.31	0.57	0.59	0.35	0.15	0.19	0.18	0.11	0.04	0.00	0.04
Netherlands	0.25	0.43	0.21	0.43	0.59	0.69	1.00	0.86	0.45	0.59	0.82	0.50	0.11	0.07	0.09	0.03	0.07	-0.07	-0.01
Belgium	0.23	0.37	0.16	0.49	0.45	0.73	0.86	1.00	0.33	0.79	0.70	0.41	0.11	0.20	0.19	0.05	0.05	-0.01	0.03
Poland	0.17	0.57	0.39	0.25	0.65	0.31	0.45	0.33	1.00	0.32	0.73	0.72	0.26	-0.04	0.01	0.19	0.09	-0.12	-0.02
France	0.20	0.30	0.12	0.41	0.35	0.57	0.59	0.79	0.32	1.00	0.61	0.43	0.25	0.46	0.35	0.15	0.17	0.04	0.08
Germany	0.26	0.55	0.33	0.38	0.73	0.59	0.82	0.70	0.73	0.61	1.00	0.77	0.20	0.17	0.19	0.11	0.11	-0.10	0.02
Czechia	0.17	0.40	0.30	0.26	0.44	0.35	0.50	0.41	0.72	0.43	0.77	1.00	0.51	0.06	0.07	0.18	0.25	-0.10	0.07
Austria	-0.02	0.07	0.04	0.14	0.07	0.15	0.11	0.11	0.26	0.25	0.20	0.51	1.00	0.23	0.14	0.29	0.45	0.07	0.10
Spain	-0.04	-0.06	-0.04	0.08	0.07	0.19	0.07	0.20	-0.04	0.46	0.17	0.06	0.23	1.00	0.79	0.18	0.23	0.24	0.01
Portugal	-0.03	-0.01	0.02	0.10	0.12	0.18	0.09	0.19	0.01	0.35	0.19	0.07	0.14	0.79	1.00	0.11	0.11	0.13	0.02
Romania	0.05	0.10	0.08	0.05	0.10	0.11	0.03	0.05	0.19	0.15	0.11	0.18	0.29	0.18	0.11	1.00	0.20	0.32	0.02
Italy	-0.05	-0.04	0.00	0.02	0.00	0.04	0.07	0.05	0.09	0.17	0.11	0.25	0.45	0.23	0.11	0.20	1.00	0.19	-0.05
Greece	-0.01	-0.07	-0.06	-0.04	-0.12	0.00	-0.07	-0.01	-0.12	0.04	-0.10	-0.10	0.07	0.24	0.13	0.32	0.19	1.00	-0.09
Cyprus	-0.04	-0.01	-0.09	0.08	0.00	0.04	-0.01	0.03	-0.02	0.08	0.02	0.07	0.10	0.01	0.02	0.02	-0.05	-0.09	1.00

Near neighbour countries have strong correlations because they lie under the same weather system much of the time. There is no significant degree of anti-correlation – necessary for the wind to be blowing somewhere else – even for distant countries.

April 2020: Extreme Price Volatility and Negative Export Prices

The chart uses BMRS data at settlement period resolution to show how prices swung negative when wind generation was high enough to cause export surpluses



The same data, but focussing on just the interconnectors and pumped storage, showing the effects of surplus wind across the British Isles more clearly. Continental markets were not prepared to pay a higher price to absorb a modest level of surplus. This will only get much worse as the size of surpluses increase, and as wind generation capacity is expanded elsewhere as well. It will then become a question of the most economic to curtail, taking account of grid constraints, across the system as a whole. The details of the economic and contractual arrangements for curtailment and of the nature of grid constraints will become crucial determinants of what actually happens across Europe as a whole, just as they affect what is happening in the UK.