Grid-scale electricity storage
enabling renewables to power grids
affordably, reliably and resiliently

Storelectric

National Grid Winter Outlook Report 2020-21 – Analysis

Introduction

National Grid published its [2021-22 Winter Outlook Report]() in October, which analyses forecast supply and demand, to establish the extent of comfort (or otherwise) during that period. It follows some press releases about [narrow forward supply margins](). These press releases assure the public that the supply margins will be adequate, at 5.3-9%; this analysis looks into that assurance.

Conclusion

Stripping out generation which will all be zero during times of system stress, and interconnectors which may well be so, the claimed comfortable supply margin drops to a **deficit of 19.1 GW, or 30%** of {peak demand plus supply margin}. Excluding the supply margin, the deficit is 12.3GW or 21% of the lower {peak demand only} figure.

Demand

ACS (Average Cold Spell) peak demand, "including 1.5GW reserve requirement" (p4), is 59.5GW (p4). This reserve is the "operating reserve". Therefore the actual ACS demand is 58GW.

Other European countries work on a supply margin (in case of any faults in either the supply or the grid) of 10-15% of peak demand. Based on 58GW peak demand, this is 5.8-8.3GW reserve – and National Grid is only planning on 1.5GW, much too low.

The p12 analysis focuses on "normalised peak transmission system demand", 46.9GW, which in turn depends on substantial attenuation of demand due to local generation and storage; this is further reduced by the "maximum triad avoidance", 1.2GW, yielding a net peak demand of 45.7GW. The local ("embedded" generation included is 6.5GW wind (2.8GW after applying its load factor of 43.4%) and 13.1GW solar (1.4GW at 10.5% load factor). This is complacent: during times of system stress, all distributed renewable generation will be negligible and local storage will be exhausted. Therefore this 2.8GW wind and 1.4GW solar need to be added to the 46.9GW, to yield 51.1GW peak transmission system demand. This is confusing: how can it be reconciled with the 58GW peak demand two paragraphs above? And using "transmission system demand" in the calculation of margins, not total demand, is not credible – as also for Storage, below: it deducts de-rated renewable generation and storage from total demand, yet a windless winter evening will have no renewable generation and exhaust most storage.

De-Rated Generation

Supply is calculated using de-rated margins (see p4 para.3), which is correct for analysis of statistical averages but useless for keeping the lights on.

The Future Energy Scenarios Workbook sheet SV.26 gives the load factors, which are another way of saying de-rated output, for various technologies in the table on the right. Using offshore wind as an example, this means that at all times the Winter Outlook report expects to have 49.9% of offshore wind nameplate capacity (i.e. 5.21GW) entering the grid from offshore wind. This may be the average that the grid gets, but during windless days it gets none. Likewise, solar will not provide 10.5% of 13.05GW = 1.37GW during a winter evening peak, because that peak occurs after sunset.

2020			
Selected technologies			
Generation type	Capacity (GW)	Load factor	Generation (TWh)
Biomass	4.43	20.2%	7.84
Gas	35.62	29.4%	91.70
Nuclear	7.07	76.2%	47.20
Offshore Wind	10.45	49.9%	45.66
Onshore Wind	12.68	39.1%	43.42
Solar	13.05	10.5%	12.02

This error is demonstrated by the fact that they focus on the day-to-day view (p5), not the hour-to-hour view which would show the lack of solar after sunset, and not the weather-variable view in which certain weather patterns produce a lot of wind while others produce little or none – and similarly, some days are sunny and others overcast or misty.

Confusingly, these load factors differ from the load factors used for calculating TNUoS, see p10; the differences are not explained. And worse than that, this Winter Outlook Report appears to use the much more optimistic factor of 100% minus assumed breakdown rate (see table, right, from p16).

Power Station Fuel Type	Assumed Breakdown Rate 20/21	21/22
Coal	9%	11%
CCGT	5%	6%
Nuclear	9%	9%
OCGT	5%	5%
Biomass	3%	5%
Hydro	8%	9%
Wind EFC	16%	17%
Pumped storage	2%	3%

Table 3. Breakdown rates by fuel type (based on a 3-year rolling average)

Loss of Load Expectation (LOLE) is similarly a statistical analysis and will suffer similar statistical problems.

The calculated de-rated margin is ~6.5%. However the stated 1.5GW on 58GW demand is only 2.6%, which does not reconcile. And even so, it is still between one-half and one-third of the margin considered necessary by most other European utilities.

They do state p8 that they performed weather-related sensitivity analyses, and p11 hat they "use a low wind scenario", but don't divulge what they are – and "low wind" does not mean zero wind. This means that we have to do our own.

Storage

This forecast includes an un-stated amount from batteries. These do not figure openly in the calculations in this report because batteries are all distribution connected or behind the meter. However they do figure in the calculation (not shown in the workbook) of "transmission system demand" as they are used as part of the reduction from total demand to transmission demand. Other parts of this reduction are the de-rated distributed solar and wind generation, both of which will also be zero during a windless winter evening.

All distribution connected and most distributed batteries have durations under 2 hours at peak load, most under 1 hour. These will be exhausted part-way through a windless winter evening, so cannot be relied upon for capacity margin.

Interconnectors

Interconnector load factors can be found in the Capacity Market Auction Parameters, and differ greatly between interconnectors:

Table 2: Interconnector de-rating factors

Interconnector	Capacity (GW)	T-1 auction 2022/23 Delivery Year		T-4 auction 2025/26 Delivery Year	
		NG:ESO range (%)	Recommended DRF (%)	NG:ESO range (%)	Recommended DRF (%)
IFA (France)	2	-	-	59-97	69
IFA2 (France)	1	-	-	59-97	71
ElecLink (France)	1	-	-	59-97	75
BritNed (Netherlands)	1.2	-	-	49-88	66
Moyle (Northern Ireland)	0.5	-	-	10-97	49
EWIC (Republic of Ireland)	0.5	-	-	10-97	49
NemoLink (Belgium)	1	-	-	22-82	65
NSL (Norway)	1.4	-	-	78-96	83
VikingLink (Denmark)	1.4	-	-	47-87	63

Total interconnector capacity is (ignoring the Irish ones) 9GW; sensibly, National Grid assumes 0.75GW exports to Ireland during peak (p15), yielding a net 8.25GW. This Winter Outlook Report assumes a 51% load factor, reducing it to 4.2GW.

However, Belgium, Denmark, Ireland and the Netherlands all already depend on imports during times of system stress, and Germany's supply margin is dropping precipitously. This means that there may not be sufficient energy available in any of the interconnectors except Norway's during times of system stress, especially in the event of a *kalte Dunkelflaute* ("cold dark doldrums", a weather pattern that reduces renewable generation to <10% for up to a fortnight across most of Western Europe during winter peak demand). Therefore the de-rated capacity of all interconnectors during time of need in the UK should be just 83% of Norway's 1.4GW = 1.16GW. Although there is a statement that one of the scenarios includes "no import from Europe" (p12), there is no indication that this scenario coincides (as it will) with peak demand, negligible renewable generation and exhaustion of all storage up to 4 hours' capacity.

National Grid likes to imagine that during such times, our neighbours will honour their contracts with the UK. But Brexit means that we are treated as an export destination, not as a domestic customer, giving neighbouring grids a political imperative to cut us off during times of need: who can imagine any grid telling their national government that black-outs in a major city were because they were earning a few million Euros exporting the energy that the city needed to the UK?

The report assesses this scenario as "not credible" because it calculates the "availability" of interconnectors. This is a false indicator: the true indicator is the availability of energy through the interconnectors, which will drop to zero under such circumstances.

This inability of interconnectors to supply the UK during these largely concurrent times of system stress will only get worse as Germany, France and Italy all turn negative before 2040, and Spain's drops to zero.

Calculating Margins Backwards

Mostly, there is no breakdown of supply by technology, so we will have to assume that supply will be as stated and adjust for the various corrections identified in this document such as de-rated margin and loss of interconnector flows. This can be seen below.

SUPPLY	GW
Start with the stated supply	59.5
Subtract de-rated embedded wind (2.8GW) and solar (1.4GW)	- 4.2
Subtract de-rated grid-connected wind (5.2GW) and solar (1.4GW)	- 6.6
Subtract 4.2GW imports, adding back de-rated Norway 1.2GW	- 3.0
Subtract battery storage (1GW)	- 1.0
Net Supply	**44.7**

DEMAND	GW
ACS Peak Demand	58.0
Add 10% supply margin	+ 5.8
Total demand	**63.8**

Shortfall: 19.1 GW
30% of peak demand plus supply margin

An alternative calculation, and further comments, follow.

Calculating Margins Bottom-Up

Calculated from Figure 10 in the workbook, for the minimum-generation date of Mon 10th January 2022:

Shortfall: 3.9 GW
8% of peak demand plus supply margin

Energy (MW)	Winter Outlook	Storelectric	
Nuclear	5,295	5,295	
Biomass	3,428	3,428	
CCGT	27,169	27,169	
Coal	3,860	3,860	Should be 0
Hydro	1,031	1,031	
OCGT	1,054	1,054	
Other	160	160	
Pumped storage	2,600	2,600	
Wind (EFC)	3,079	0	No wind
Total generation	47,674	44,595	
Interconnectors	4,853	1,160	Norway only
Total available	52,528	45,755	
Transmission demand	45,170	45,170	
+10% margin	49,687	49,687	
Surplus / Deficit	2,841	- 3,932	

However it is not credible: transmission demand is calculated by deducting distributed generation and storage from all demand. As, during a windless winter evening, distributed generation is zero and storage (mostly below 2 hours duration) is exhausted, the forecast transmission demand is artificially suppressed to that extent. There are no figures in the Workbook to enable us to reverse out these bad assumptions, so we must rely on the backwards calculation.

"Told You So"

Although out of scope of this analysis, it is interesting to note that electricity prices rose exponentially from twice the price of last year in July, rising towards five times by the end of September. Such increased costs of electricity have long been forecast by Storelectric as an outcome of the lack of sufficient large-scale long-duration electricity storage, which would have greatly suppressed demand for gas for balancing and stability services. The "told-you-so" feeling is not compensation for the sadness that the first-of-a-kind of such storage has not been funded, and the regulatory and contracting system have not been adapted to ensure that sufficient such storage can be financed without subsidy and without increasing the total system costs. We have frequently advocated such changes to achieve such a result, so far fruitlessly.

Similar "told you so" out-turns have included the 2019 black-outs and many near misses since, the ever-increasing non-energy costs of electricity, the sky-rocketing balancing and ancillary services costs demonstrated during the first lockdown, the inability of current markets and regulations to ensure that large-scale long-duration storage projects are built. A fuller assessment of the current state of regulations and the market is here. One wonders when they will listen properly.

Worse, BEIS recently put out consultations in which they say that they are considering "long term" planning of 10 years. This is not long term: it's short to medium term. Long term is 30-50 years. Unless planning, strategies and regulations are long term, the energy transition will never be affordable, reliable or resilient, and will be too disruptive.

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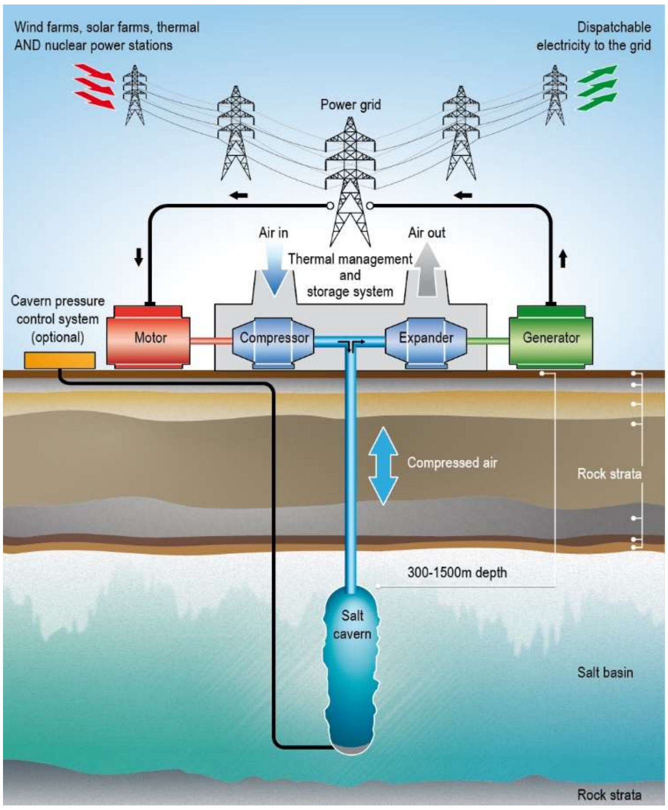
About Storelectric

Storelectric (www.storelectric.com) is developing transmission and distribution grid-scale energy storage to enable renewables to power grids reliably and cost-effectively: the world's most cost-effective and widely implementable large-scale energy storage technology, turning locally generated renewable energy into dispatchable electricity, so… ***enabling renewables to power grids cheaply, efficiently, reliably and resiliently***.

- Innovative adiabatic Compressed Air Energy Storage (Green CAES) will have zero / low emissions, operate at 68-70% round trip efficiency, levelised cost significantly below that of gas-fired peaking plants, and use existing, off-the-shelf equipment.
- Hydrogen CAES technology converts & gives new economic life to gas-fired power stations, reducing emissions and adding storage revenues; hydrogen compatible.



Both technologies will operate at scales of 20MW to multi-GW and durations from 4 hours to multi-day. With the potential to store the entire continent's energy requirements for over a week, global potential is greater still. In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES, all of which will greatly improve storage cost, duration, efficiency and global potential.

About the Author

Mark Howitt is Chief Technical Officer, a founding director of Storelectric. He is also a United Nations expert advisor in energy transition technologies, economics, regulation and politics – invitation here.

A graduate in Physics with Electronics, he has 12 years' management and innovation consultancy experience world-wide. In a rail multinational, Mark transformed processes and developed 3 profitable and successful businesses: in commercialising a non-destructive technology he had innovated, in logistics (innovating services) and in equipment overhaul. In electronics manufacturing, he developed and introduced to the markets 5 product ranges and helped 2 businesses expand into new markets.

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