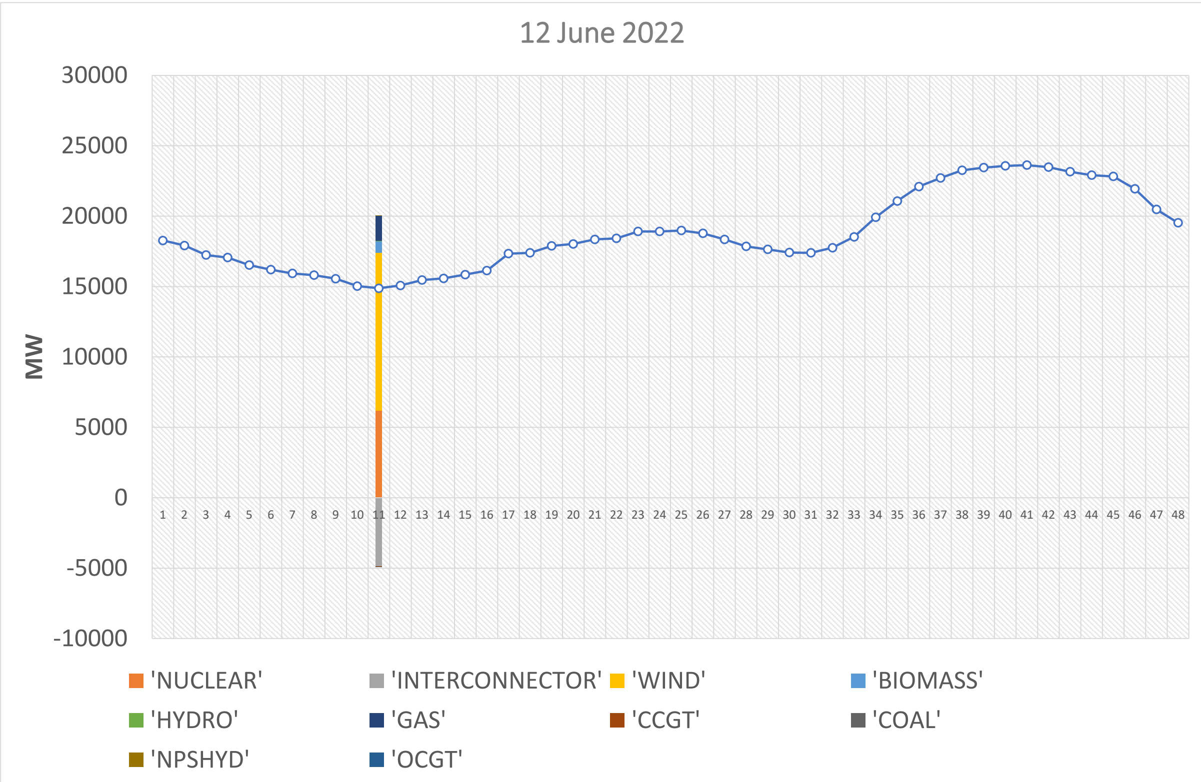
Controllability case for GC 0117

NGESO believe that controllability with visibility is necessary if GC00117 is implemented.
More capacity in the Balancing Mechanism leads to more competition in an efficient market which translates to lower costs for system operation.

The case is more apparent when looking at summer minimum demands where previous analysis focused on peaks.

The 12-June-2022 is our case study to set the scene.

Minimum demand was 15GW, wind was 11GW and continental interconnectors were flowing out of GB. Inflexible generation comprised of nuclear and voltage/inertia plant. Nearly 2.7GW of wind bids were taken at a cost of ~£0.30m for one settlement period. The constraint costs for the day were £15m and the total cost of balancing £20m. The FPNs are taken here with the latest wind forecast prior to real time and the day ahead interconnector position to show a typical control room situation. Overall, an expensive day.



We look at the impact on costs with and without the grid code mod keeping assumptions constant.

Case 1:

A future with 3GW of ‘small’ new wind

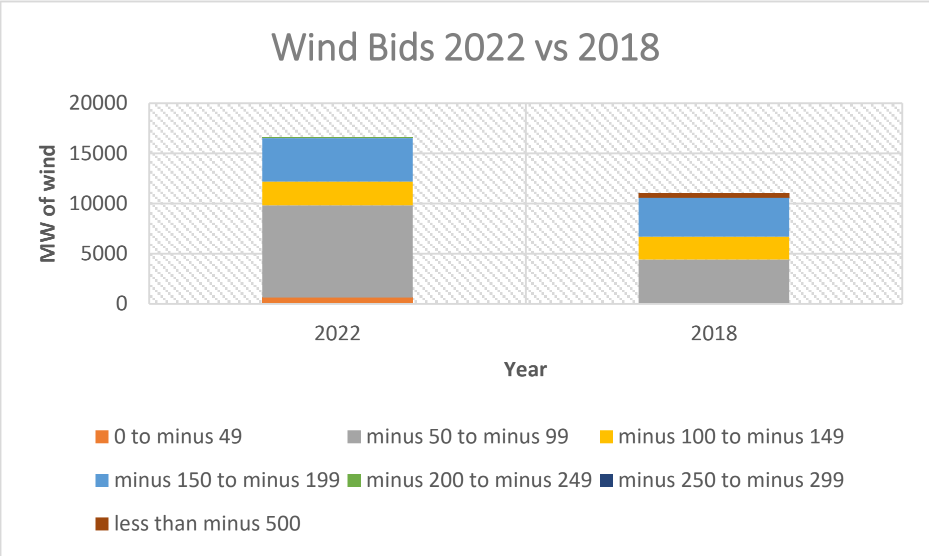
	Future +3GW	
	No GC	With GC
Minimum demand (MW)	13350	15000
Units required (MW)	9000	9000
Emb Wind capacity (MW)	9000	6000
BMU Wind capacity (MW)	20000	23000
Wind load factor	0.55	0.55
BMU Wind generation (MW)	11000	12650
Wind Action required (MW)	**6650**	**6650**
Proportion of wind BOAd	60%	53%
Marginal Wind Price -£/MWh	£ 149	£ 99
Wind Action cost	£ 495,425	£ 329,175
Cost differential		£ 166,250

Firstly, without the mod, this generation volume becomes embedded without control. Our minimum demand falls from where it is today to 13.35GW (netting de-rated generation). Our requirements for voltage (2GW), inertia (2GW) and inflexible nuclear power (5GW) are 9GW. Today we have ~6GW of embedded wind with the additional 3GW we reach 9GW. Metered transmission wind is ~20GW. The difference between the demand and the inflexible generation is what needs to be actioned – we focus here on wind - 6.65GW of wind. The important point here is the proportion of BMU wind being actioned. From the price stack below, we have the distribution of metered wind per price bracket from June last year. The marginal price here is between £-100 to £-149/MWh.

The alternative case, with the mod is that the generation is metered, visible and controllable and a part of national demand. The embedded wind stays at the existing level but the BMU wind capacity grows. The amount of wind to be action is the same (6.65GW) but the key difference here is that the proportion of BMU wind is less. This places us at a lower price bracket and therefore lower total cost. In isolation this is £0.17m less. This is potentially £8m per day.

We have modelled 3 other scenarios, with 6GW, 9GW and 12 GW of new wind. The savings using the same approach are £0.4m, £0.25m and £0.6m. One key point to note is that under a 12GW scenario we need more wind than is available in the BM making this an operability issue in addition to an economic issue. However, the ‘With GC’ mod scenario is operable.

BM wind available by price bracket £/MWh



The case is further strengthened when looking at the afternoon demand trough. This year we have seen a demand at 14.8GW at 14:30 on 27 May. The impact of solar generation also becomes an important factor. Looking at load factors from the summer so far, we have a max of 0.75 for solar and 0.67 for wind. An average of 0.71 is applied. Wind prices from May 2023 are also refreshed here. The summary is presented in Appendix 2.

The savings are £0.07m, £0.5m, £2.7m, £3.2m for our 4 scenarios however 2 of our 4 scenarios are inoperable. Under such circumstances the control room have emergency instructions which can be sent to wind farm operators. Our analysis is looking nationally however you can get localised issues which can be more challenging. A NRAPM (Negative Reserve Active Power Margin) forecast for Daily 2-14 days ahead and Weekly for 2-52 weeks ahead for both National and Scotland is published on the data portal. The purpose of the NRAPM forecast is to indicate to the market a risk of NRAPM situation and therefore risk of Emergency Instructions.

The insufficient NRAPM warning is a request to encourage more flexible parameters from generators and inform participants of a risk of emergency instructions. A system NRAPM may be issued if there is insufficient flexibility available to ensure that generation matches demand during low demand periods. Controllability can help avoid the use of Emergency Instructions.

One of the features of CFD wind is that during negative price periods no payment is made from LCCC to the generator[1]. When these periods occur, it can coincide with a dramatic withdrawal of wind generation from the system with little coordination. This creates a challenging set of circumstances with the control room balancing competing requirements for energy, ramping, constraints, reserve, and response. The ESO needs controllability to instruct offers on these wind farms to maintain system security. In a system where renewables are a growing share of the fuel mix, controllability to manage this phenomenon is essential.

[1] For AR2,3 negative price period is 6 consecutive hours and AR4 any hour

Appendix 1 overnight demand minimum

	Current	Future +3GW		Future +6GW		Future +9GW		Future +12GW	
		No GC	With GC	No GC	With GC	No GC	With GC	No GC	With GC
Minimum demand (MW)	15000	13350	15000	11700	15000	10050	15000	8400	15000
Units required (MW)	9000	9000	9000	9000	9000	9000	9000	9000	9000
Emb Wind capacity (MW)	6000	9000	6000	12000	6000	15000	6000	18000	6000
BMU Wind capacity (MW)	20000	20000	23000	20000	26000	20000	29000	20000	32000
Wind load factor	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
BMU Wind generation (MW)	11000	11000	12650	11000	14300	11000	15950	11000	17600
Wind Action required (MW)		**6650**	**6650**	8300	8300	9950	9950	11600	11600
Proportion of wind BOAd		**60%**	**53%**	**75%**	**58%**	**90%**	**62%**	**105%**	**66%**
Marginal Wind Price -£/MWh		£ 149	£ 99	£ 199	£ 99	£ 199	£ 149	£ 249	£ 149
Wind Action cost		£ 495,425	£ 329,175	£ 825,850	£ 410,850	£ 990,025	£ 741,275	£ 1,444,200	£ 864,200
Cost differential			**£ 166,250**		**£ 415,000**		**£ 248,750**		**£ 580,000**

Appendix 2 afternoon demand minimum

	Current	Future +3GW/+1GW		Future +6GW/+2GW		Future +9GW/+3GW		Future +12GW/+4GW	
		No GC	With GC	No GC	With GC	No GC	With GC	No GC	With GC
Minimum demand (MW)	15000	12160	15000	9320	15000	6480	15000	3640	15000
Units required (MW)	9000	9000	9000	9000	9000	9000	9000	9000	9000
Emb Wind capacity (MW)	6000	9000	6000	12000	6000	15000	6000	18000	6000
Emb Solar capacity (MW)	13000	14000	13000	15000	13000	16000	13000	17000	13000
BMU Wind capacity (MW)	20000	20000	23000	20000	26000	20000	29000	20000	32000
BMU Solar capacity (MW)	0	0	1000	0	2000	0	3000	0	4000
Wind/Solar load factor	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
BMU Wind generation (MW)	14200	14200	16330	14200	18460	14200	20590	14200	22720
BMU Solar generation (MW)	0	0	710	0	1420	0	2130	0	2840
Wind Action required (MW)		**11040**	**10330**	13880	12460	16720	14590	19560	16720
Proportion of wind BOAd		**78%**	**63%**	**98%**	**67%**	**118%**	**71%**	**138%**	**74%**
Marginal Wind Price -£/MWh		£ 199	£ 199	£ 249	£ 199	£ 500	£ 199	£ 500	£ 199
Wind Action cost		£ 1,098,480	£ 1,027,835	£ 1,728,060	£ 1,239,770	£ 4,180,000	£ 1,451,705	£ 4,890,000	£ 1,663,640
Cost differential			**£ 70,645**		**£ 488,290**		**£ 2,728,295**		**£ 3,226,360**