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1 Evolution of primary frequency control requirements in
2 Great Britain with increasing wind generation

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6 **Abstract**

7 With the increase of renewable generating capacity following the ambitious
8 targets set by many governments for the next decades, there will be major
9 changes in power generation and challenges for balancing transmission grids.
10 In particular, primary frequency control requirements will be increased fol-
11 lowing a potential reduction of system inertia.

12 An assessment of the frequency response reserve needed is made through
13 use of a simple model of the Great Britain transmission grid for different loads
14 and wind power penetration. This model analyses the effect of changing the
15 system inertia and the effectiveness of standard frequency response as well
16 as dynamic frequency control support.

It is observed that an increased wind power generation requires substan-
tial additional reserves for primary frequency control if the wind turbines do
not contribute to the overall system inertia. However, it is also shown that
these reserves can be dramatically reduced if the system is provided with fast
acting response by dynamic frequency control support.

17 *Keywords:* Reserves, wind power, frequency control, frequency stability,
18 power system

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19 1. Introduction

20 Traditionally, electricity grids are dominated by synchronous generators
21 linked directly to the grid, and the mechanical inertia in the rotating ma-
22 chinery provides inertia to the grid frequency such that imbalances in supply
23 to demand result only in a relatively slow change of the grid frequency which
24 can easily be corrected. However, with globally increasing contribution of
25 power from wind and PV through inverters, this inertia is effectively reduced
26 as inverters do not provide any intrinsic inertia. Furthermore, most renew-
27 able power can only be controlled through curtailing output, which is useful
28 if supply exceeds demand, but not in the other case where demand exceeds
29 supply. A critical case of the latter situation arises if there is a sudden loss
30 of generation.

31 The British government (DECC) has set a target of delivering 15% of its
32 energy demand from renewable energy sources by 2020 [1, 2]. This is dictated
33 by the Climate Change Act of 2008 setting a target of 80% reduction of CO₂
34 emissions (compared to 1990) by 2050, with at least a 34% reduction by 2020
35 and 60% reduction by 2030. In particular, the UK government is confident to
36 achieve a 30% electricity generation from renewable energy sources [2]. This
37 means that the installed generating capacity is likely to change dramatically
38 over the next years and even further by 2030. Based on different scenarios,
39 it is expected that transmission connected variable renewable generation will
40 exceed the minimum load (and possibly even peak load) by 2030 as shown
41 in figure 1 (further details provided in table 1).

42 In all scenarios, the instant proportion of renewable generation on the
43 grid, in particular wind power in the UK, will increase. Since the character-
44 istics of this generation differs from conventional generation, it is important
45 to study the need for changes in power system operation at times with high
46 instant penetration level of wind power. As a reminder, the instant share of
47 wind generation at time t is defined as the ratio of combined wind power fed
48 into the network to the total output of all grid-connected generators at the
49 particular point in time. This instant penetration level is key when assessing
50 the impact of wind power generation on the grid.

51 One of the key challenges is to maintain the grid frequency within speci-
52 fied limits. In traditional large transmission systems, the combined electro-
53 mechanical inertia of the rotating machinery directly linked to the grid pro-
54 vided frequency inertia which allowed enough time for corrective action [4,
55 5, 6]. The nature of both, the resource and the technology to convert wind

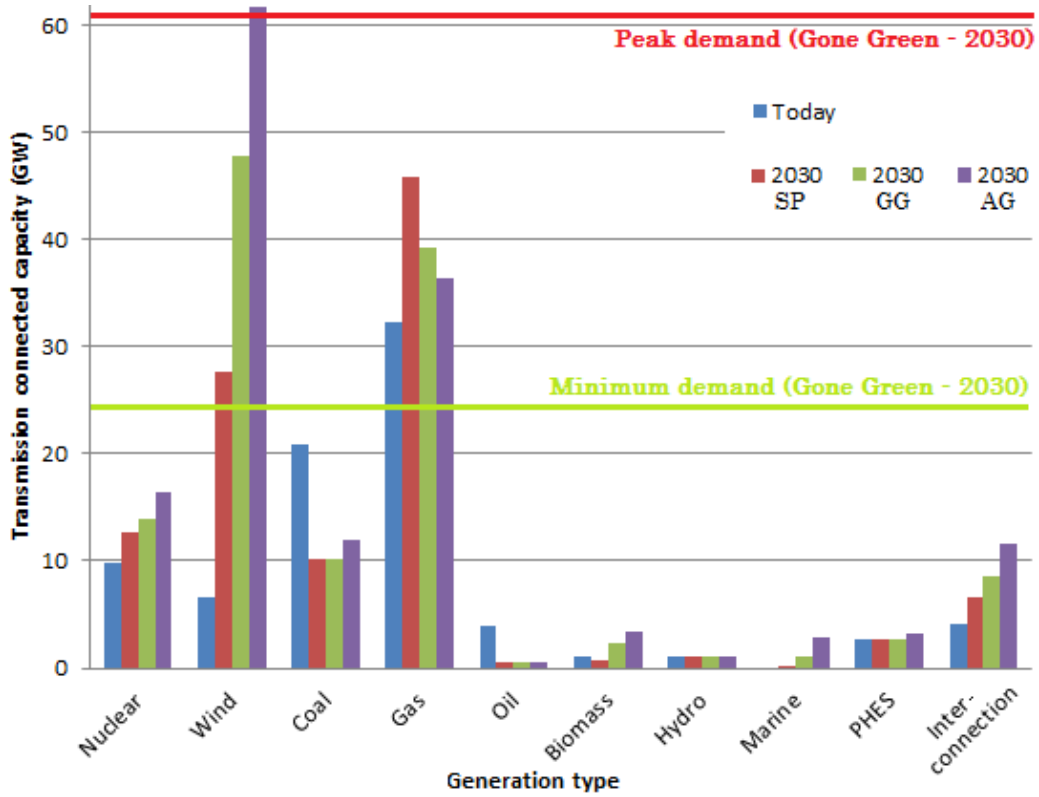


Figure 1: Evolution of transmission connected capacity in Great-Britain by 2030 under various scenarios (data: National Grid [3]).

56 power, do not necessarily contribute to that frequency inertia and additional
57 reserve generation or control strategies have to be used [7, 8, 9, 10, 11]. The
58 same also applies to other variable resources, such as PV [12].

59 When trying to reduce greenhouse gases emissions, not only generation
60 directly feeding into the grid has to be considered, but also generation kept
61 into reserve for system balance mechanism. In particular, part loaded conven-
62 tional plants contributing to primary frequency control run at lower efficien-
63 cies, and the consequence is that the associated greenhouse gases emissions
64 are increased [8]. It is therefore important to understand the effectiveness
65 of frequency control strategies and their demand on the plant providing this
66 to find ways to reduce their environmental impact as much as possible while
67 providing security and quality of supply.

68 *1.1. Aims and objectives*

69 From all these impacts, this article focuses on the particular aspect of
70 response capacity needed to cope with the loss of the largest generating unit
71 on the UK transmission grid. This aspect of security of supply is particularly
72 important for keeping the system operating within safe limits preventing
73 blackouts due to cascading trip of generating units. With this focus in mind,
74 the objectives of this work are to simulate and analyse the response of the
75 grid following loss of generation under a range of demand and wind power
76 conditions for a choice of frequency control strategies for the wind power.
77 From these simulations, the required power level of response action to keep
78 the grid frequency within the legal range is determined as the key measure.

79 The remainder of this section will first state the projected electricity
80 generation targets and power quality constraints for the UK and then provide
81 an overview over Great Britain's current power system and wind turbine
82 generator technologies. Frequency regulation strategies and actions to ensure
83 compliance with power quality constraints are introduced in §2. The model
84 to investigate the response of the grid to primary frequency control actions is
85 developed in §3. The simulation results are presented in §4, and conclusions
86 drawn for the future of frequency regulation in §5.

87 *1.2. Future electricity generation in Great Britain*

88 National Grid has published three reference scenarios [3] for future elec-
89 tricity requirements in Great Britain by 2030:

90 **Slow progression (SP):** the economy is restarting slowly after the crisis,
91 with environmental targets met late.

92 **Gone green (GG):** the economy is restarting slowly with environmental
93 target met according to schedule.

94 **Accelerated growth (AG):** the economy is restarting fast with significant
95 growth and focus on environmental targets being met on schedule.

96 Figure 1 and table 1 show the associated changes in generating capacity
97 to be expected by 2030 according to these scenarios. These three scenarios
98 form the basis of the load and wind power conditions for our model.

99 *1.3. Frequency standards in Great Britain*

100 The nominal value of the grid frequency on European grids including
101 that of the UK is $f_0 = 50$ Hz. Frequency standards are described in National
102 Grid's *Security and Quality of Supply Standard* [13]. In particular, two re-
103 quirements are of particular interest for this study, namely those concerning
104 the power frequency following a *normal* or *infrequent* loss of generation,
105 which are classified according to the magnitude of loss of power [14]:

- 106 • Following a normal loss of generation, specified as 1,320 MW from April
107 2014, the frequency must not fall below 49.5 Hz.
- 108 • Following an infrequent loss of generation with a loss of 1,800 MW, the
109 frequency must return above 49.5 Hz within 60 s.

110 In line with the study's aims, these two threshold values of loss of generation
111 were used in the model to investigate the level of generation response required
112 to comply with these regulations for ranges of load-wind power situations
113 expected within the scenarios outlined in §1.2.

114 *1.4. Great Britain's transmission grid*

115 National Grid is responsible for the system operation in Great Britain,
116 in accordance with the terms of the Transmission Licence granted by the
117 British regulator OFGEM. This transmission system is linked to France, the
118 Netherlands, Northern Ireland and the Republic of Ireland through DC links
119 so that its synchronous zone is limited to the main island of Great Britain
120 itself (and small neighbouring British isles such as the Hebrides and the Isle
121 of Man).

122 Figure 2 shows typical demand profiles on the transmission grid (not
123 including storage action adding to demand) over the course of the day and

Table 1: Predictions of installed transmission-connected capacity evolution (data: National Grid [3]).

Type	Scenario	Installed capacity (GW)		
		2013	2020	2030
Nuclear	SP		9.5	12.6
	GG	9.9	9.5	13.9
	AG		8.7	16.4
Conventional thermal	SP		57	57.2
	GG	57.8	55.6	52.3
	AG		57.4	52.3
Hydro	SP		1.1	1.1
	GG	1.1	1.1	1.1
	AG		1.1	1.1
Wind	SP		13.4	27.6
	GG	6.8	25.6	47.7
	AG		33.0	61.6
Pumped storage	SP		2.7	2.7
	GG	2.7	2.7	2.7
	AG		3.3	3.3
Inter-connection	SP		5.2	6.6
	GG	4.2	6.6	8.6
	AG		6.6	11.6
Total (transmission-connected)	SP		88.9	101.8
	GG	82.7	101.1	127.5
	AG		110.4	149.3

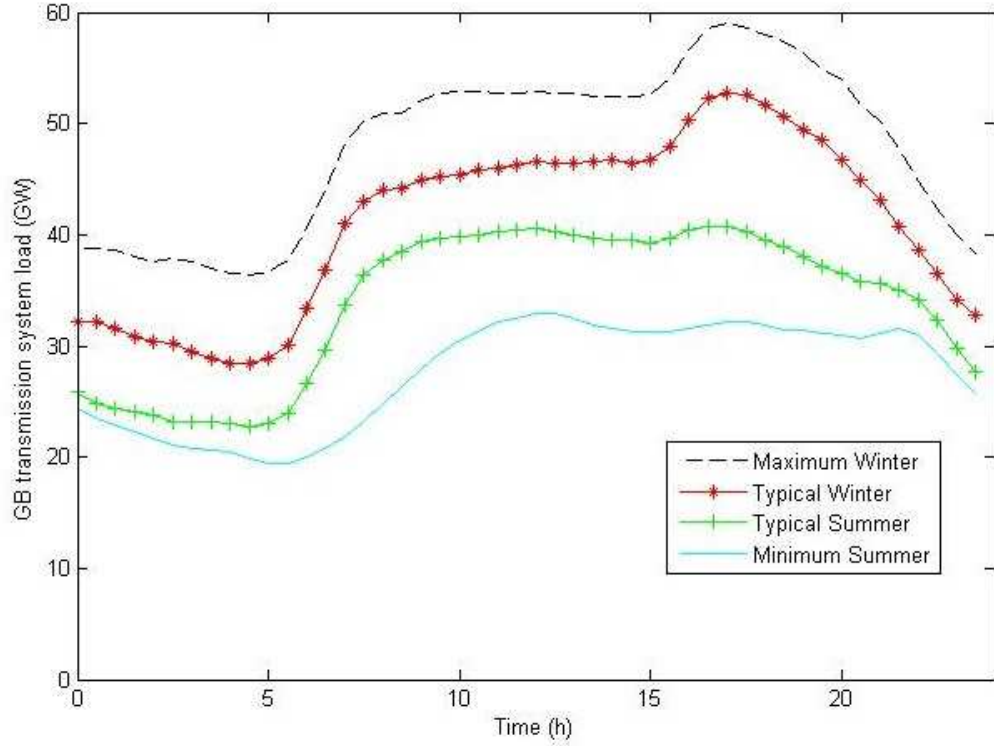


Figure 2: Typical transmission system load profiles on GB transmission grid in 2010-2011 (data: National Grid [15]).

Table 2: Evolution of minimum and peak demand [16].

Year	Scenario	Demand (GW)	
		Minimum	Peak
2013		23	57.7
2020	SP	23.1	57.8
	GG	23.1	57.6
	AG	23.4	58.5
2030	SP	22.7	56.6
	GG	24.3	60.7
	AG	26.3	65.7

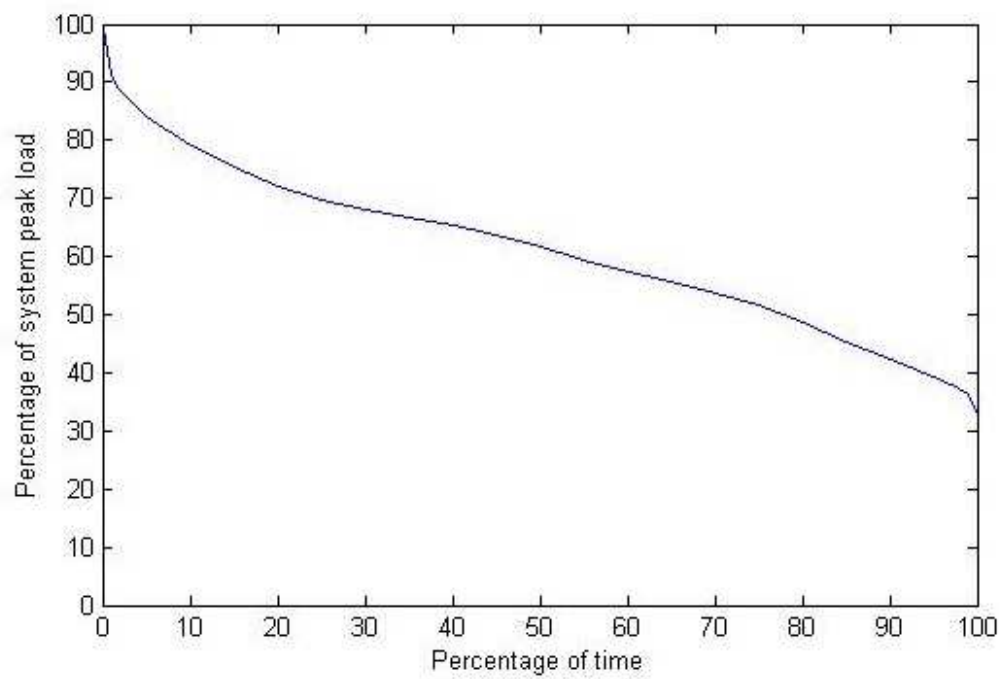


Figure 3: Load-duration curve for the GB transmission system in 2010-2011 (data: National Grid [15]).

124 the year. The peak load of a day is usually around 1.5 times the minimum
125 load taking place at the early hours of a day.

126 Figure 3 shows the distribution of load throughout the year, so that for
127 each load level the number of hours per year at which the system is operating
128 at this load may be worked out. In particular, it shows that for around 50%
129 of time, the load lies below 60% of peak load. It is therefore important to
130 consider what happens at lower loads on the system. Minimum and peak
131 system demand are expected to evolve according to the different scenarios.
132 This evolution is detailed in table 2, where all values treat small embedded
133 generation as negative load (so that it is subtracted from real load) in order to
134 consider only transmission system load. Nevertheless, with the development
135 of PHES and interconnector shown in table 1, there will be more room for
136 differences between load and generation.

137 1.5. Wind turbine generator technologies

138 Currently, four main types of generators are common for wind energy
139 converters, synchronous or asynchronous induction generators, doubly fed
140 induction generators (DFIG), and fully rated converters (FRC) [5]. While
141 the wind turbine market was in the past dominated by fixed-speed wind tur-
142 bines with induction generators, almost all modern wind turbines have vari-
143 able speed rotors and require DFIGs or FRCs. While the fixed-speed turbines
144 can be directly linked to the grid and thereby contribute to frequency sta-
145 bility through their electro-mechanical inertia, variable-speed machines have
146 many advantages. One of these is that they can optimise the aerodynamic
147 conditions and thereby optimise the power output. There is also less stress
148 on the mechanical components if the turbine can adjust its rotation rate to
149 the wind conditions independently of the grid frequency, e.g. [17]. DFIG and
150 FRC generators are decoupled from the grid through the use of back-to-back
151 rectifier and inverter between the stator and the grid, which not only allows
152 to optimise the aerodynamics but also control of the power factor. As the
153 physical motion of the rotor is now decoupled from the grid, the rotor's in-
154 ertia can no longer be used directly to provide inertia to the grid. However,
155 it is possible to provide what is called *synthetic inertia*.

156 With the development of power electronics and increase in Transmission
157 System Operators' (TSO) requirements for grid connection, there has been
158 a dramatic shift in the turbine market towards variable speed wind turbines
159 [18]. Even though the power electronics may represent around 7% of the cost
160 of a turbine, they may capture as much as 5% more energy per year [19].

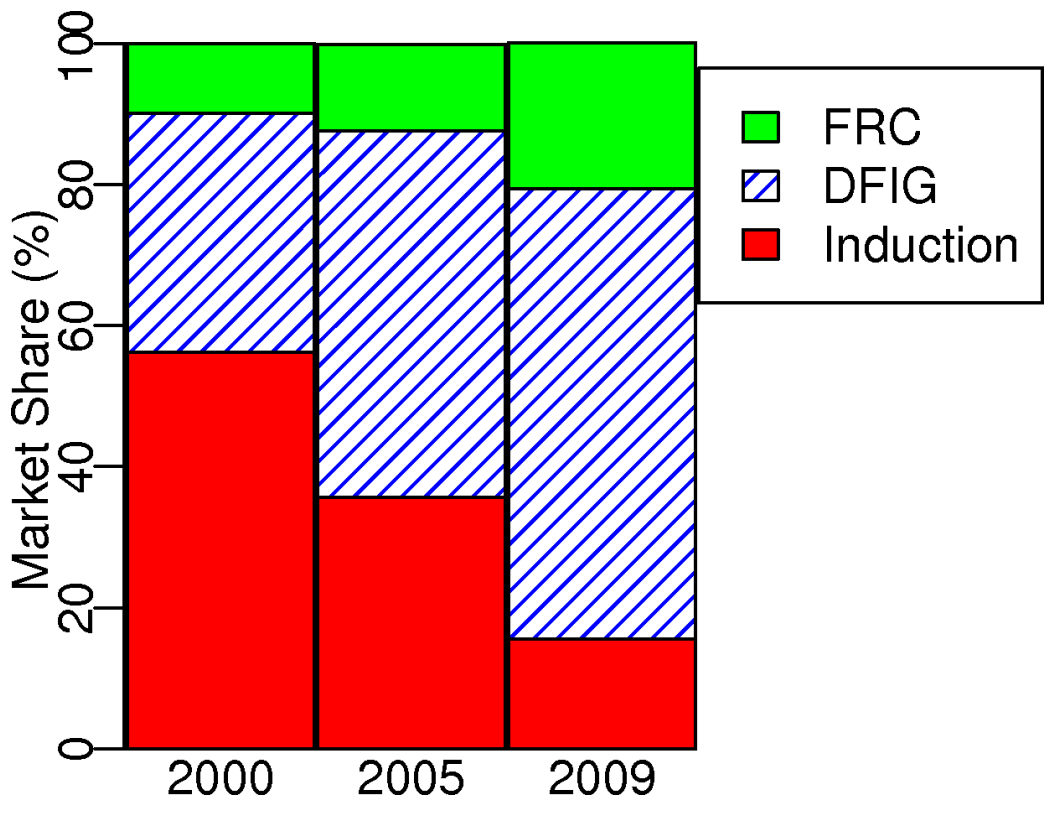


Figure 4: Evolution of WT generator types (data: [18]).

161 The evolution of the shares of different wind turbines technologies between
 162 2000 and 2009 is given in figure 4. It shows a dramatic shift towards use of
 163 power electronics based turbines generators where DFIG and, more recently
 164 FRC, dominate the market.

165 2. Frequency control stages

166 The majority of generators used in conventional power plants are syn-
 167 chronous generators. For such generators, the frequency output delivered by
 168 the generator is proportional to the rotating speed of the rotor [5]:

$$f = \frac{p \omega_m}{4\pi} \quad (1)$$

169 Where ω_m is the rotating speed of the rotor (in rad s⁻¹) and p the number
 170 of poles of the generator (i.e. twice the number of pole pairs).

171 Whenever load exceeds generation, supplementary energy will be ex-
 172 tracted from the kinetic energy of rotating parts in generators and these ro-
 173 tating parts slow down in response. Conversely, whenever generation exceeds
 174 load, kinetic energy will be added to the system and the rotors accelerate.
 175 For this reason, frequency is a key indicator of the real-time balance between
 176 supply and demand of active power on the grid. Its control is necessary at
 177 all times to ensure operation within reasonable and specified limits.

178 2.1. System inertia

179 The response of the grid frequency to the supply-demand balance is ex-
 180 pressed as (adapted from [20]):

$$\frac{df}{dt} = \frac{\Delta P f_0}{2 S_n H}, \quad (2)$$

181 where ΔP is the power imbalance (expressed in W) and defined as $\Delta P =$
 182 $P_{gen} - L_{sys}$, with P_{gen} the aggregated active power input of all generators
 183 and L_{sys} the demand, and $S_n H$ is the total system inertia. The system
 184 inertia determines the power system dynamics in response to a disturbance.
 185 While various formal descriptions are available for the inertia of individual
 186 generators or the whole system, the H factor (expressed in s or MW s/MVA)
 187 representation is used here, following e.g. [5, 21]:

$$H_i = \frac{E_{k,i}}{S_{n,i}}, \quad (3)$$

Table 3: Typical inertia constants for generators [8, 22].

Generator type	H constant (s)
Thermal 2 / 4 poles	2.5 – 6 / 4 – 10
Hydro	2 – 4
Wind (appropriate control [23])	2 – 6

188 where $E_{k,i}$ is the kinetic energy of rotors in the generator (in MJ) and $S_{n,i}$
 189 is the apparent power output of the generator (in MVA). The system inertia
 190 is composed of the apparent power output of all generators $S_{n,i}$, each with
 191 their own inertial time scale H_i as

$$H = \frac{\sum_i S_{n,i} H_i}{\sum_i S_{n,i}}. \quad (4)$$

192 The inertia of a generator depends on the generator mass, shape and ro-
 193 tational speed (function of the frequency and number of poles) for directly
 194 coupled synchronous generators used in conventional power plants [5, 21, 22].

195 For power generator connected to the grid through DC converter, it is
 196 possible to mimic the behaviour of synchronous generation through appro-
 197 priate controller action. This is known as *synthetic inertia* [20, 23] and can
 198 be used in wind turbines for example.

199 Examples of typical ranges for the inertial time constant H are given
 200 in table 3 and the influence of inertia on power system dynamics is shown
 201 in figure 5. There one can see that a lower inertia results in a faster and
 202 more pronounced drop of the grid frequency when the when a sudden loss of
 203 generation leads to a large negative power imbalance.

204 2.2. Load frequency sensitivity

205 Not only directly connected generators but also some loads, such as syn-
 206 chronous engines, vary their speed (and consequently load) in response to
 207 frequency changes. This behaviour is called *self-regulation of load* or *load fre-*
 208 *quency sensitivity* since this load change is opposed to the frequency change,
 209 and defined as [24, 8]:

$$K_L = \frac{\Delta L_{sys}/L_{sys}}{\Delta f/f_0} \quad (5)$$

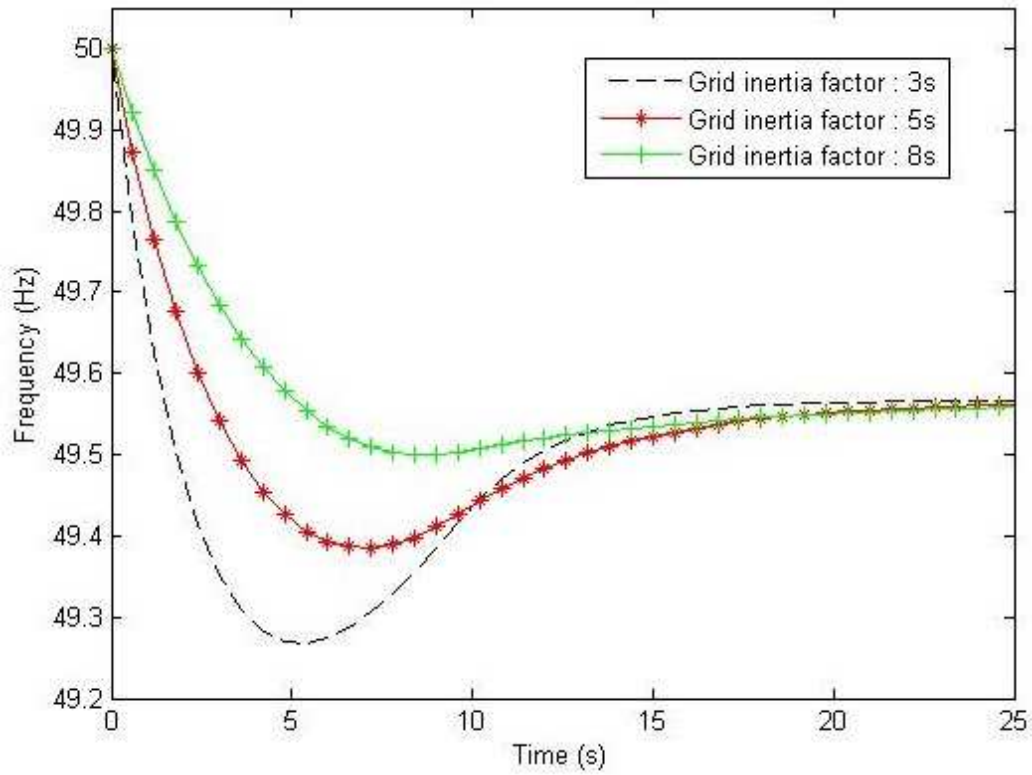


Figure 5: Influence of inertia on frequency response *ceteris paribus* (system with load of 30 GW, available PFR of 800 MW, K_L of 2 and for a loss of 1,320 MW at $t=0$).

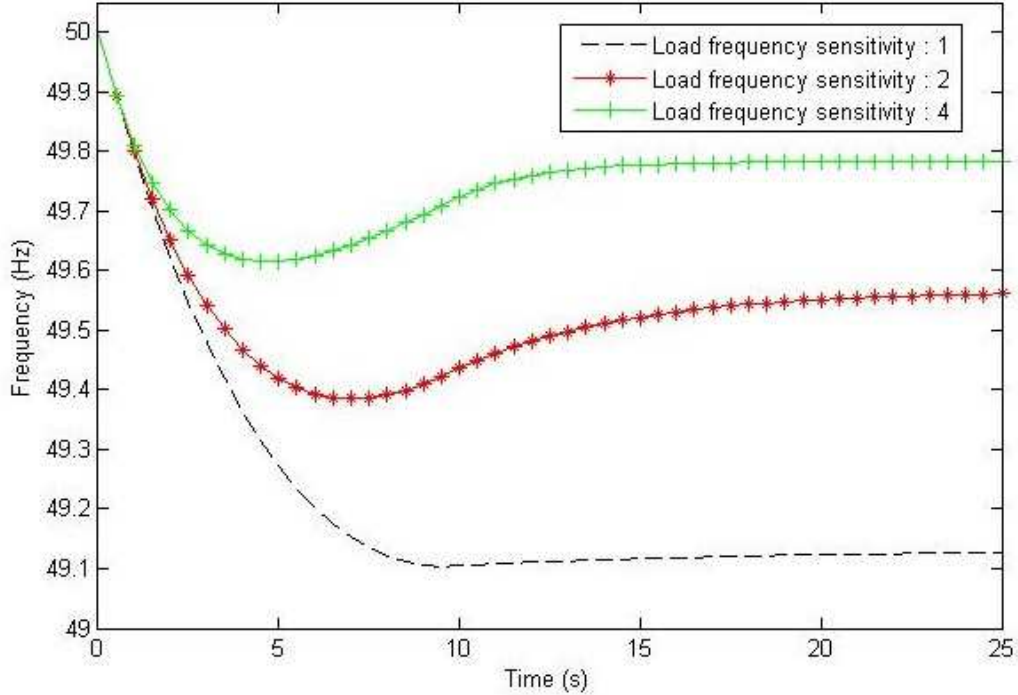


Figure 6: Influence of load frequency sensitivity on frequency response (Influence of inertia on frequency response *ceteris paribus* (system with load of 30 GW, available PFR of 800 MW, system inertia constant of 5s and for a loss of 1,320 MW at t=0).

210 Where $\Delta f = f_{qss} - f_0$ is the frequency deviation for the quasi-steady state
 211 frequency f_{qss} from the target frequency (50 Hz). While this self-regulation
 212 of load, K_L , is a dimensionless number, some authors use the pseudo-unit
 213 %MW/Hz (where 2%MW/Hz means that a drop of 1% in frequency causes
 214 a drop of 2% in the load).

215 The influence of K_L on the grid frequency is shown in figure 6. While
 216 this factor is highly dependent on the type of system and on the nature of
 217 loads connected, it is usually too small to provide full frequency regulation
 218 alone. For example, it is considered by TSOs in continental Europe to be in
 219 the range of 0.5 to 1 [25] and in the range of 1.1 to 6 in the UK [8]).

220 2.3. Types of frequency control

221 Frequency control is commonly separated into three different types of
 222 control: primary, secondary, tertiary and time frequency control.

223 The only type of frequency control investigated in this study is primary
 224 frequency control. For completeness, the other types will be presented briefly
 225 to help understanding the basics of frequency regulation on a power system.

226 2.3.1. Primary frequency control

227 Primary frequency control is the fastest deployed type of frequency con-
 228 trol. It is generally deployed within a few seconds for a duration of up to
 229 several minutes. This type of response is achieved through different mecha-
 230 nisms such as load control and turbine governor action.

231 Load control is a demand-side possibility, often based on centralised re-
 232 mote control, to regulate frequency. Some loads (such as refrigerators) may
 233 not need to be run constantly so that they may be shut down for a given pe-
 234 riod in order to contribute to frequency regulation without affecting the end
 235 user. Further studies of advanced complex dynamic control of large numbers
 236 of loads have proven the potential to add significant frequency stability to
 237 power networks [26, 27].

238 Turbine governor action happens in conventional thermal or hydro power
 239 generation. The frequency is automatically regulated using a device called
 240 governor which regulates the power input of the turbine (e.g. steam flow)
 241 according to the rotational speed in order to ensure stable operation of the
 242 generator [5, 28]. The governor action depends mainly on two parameters,
 243 the *dead band* and the *speed droop*.

244 The *dead band* of the governor determines the minimum amount of change
 245 in frequency needed before the governor action is activated. Some generating
 246 units may not participate to primary frequency control and their dead band
 247 would be set to a larger value to activate frequency control only for large
 248 disturbances [5]. As an example, the dead band of the governors installed in
 249 plants participating to primary frequency control on Great Britain’s grid is
 250 ± 15 mHz[14].

251 The *speed droop* which is the ratio of the relative change in frequency to
 252 the relative change in power output [29] (expressed in %):

$$s_G = -\frac{\Delta f / f_0}{\Delta P_G / P_{G_n}}, \quad (6)$$

253 where f_0 is the target frequency, $\Delta f = f - f_0$ is the difference between system
 254 frequency and the target frequency, P_{G_n} is the rated active power output and
 255 $\Delta P_G = P_G - P_{G_n}$ is the difference between actual power output and rated
 256 power output. This droop is always positive to ensure stable operation and

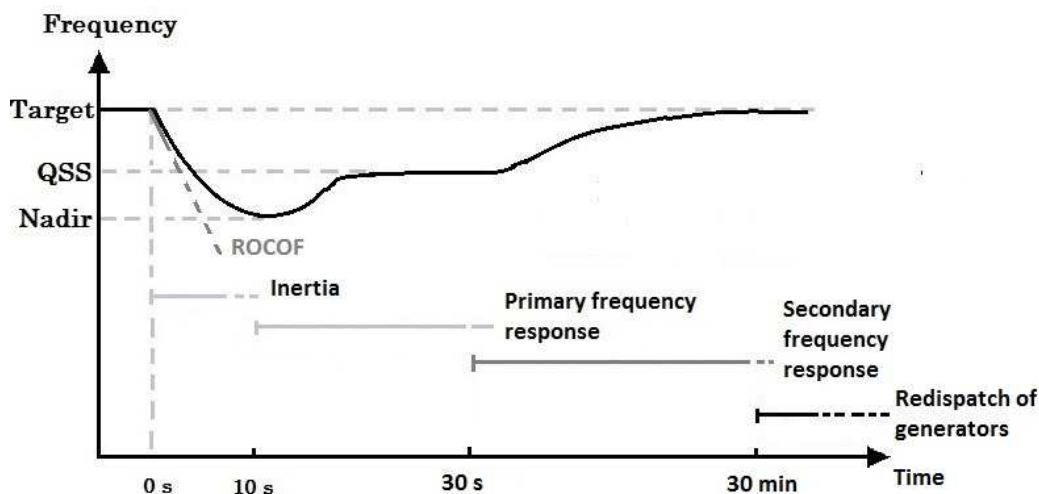


Figure 7: Summary of frequency control in Great-Britain.

257 is set to 4% in Great Britain for frequency responsive plants, although some
 258 hydropower plants may use a 1% droop [8].

259 2.3.2. Organisation of primary frequency control in Great Britain

260 Primary frequency control is organised in three different types of control
 261 on Great Britain's transmission grid: primary and secondary frequency re-
 262 sponse following loss of generation, and high frequency response following
 263 loss of load [14]. High frequency response is deployed within a 10 s window
 264 following a loss of load through progressively reducing plant output.

265 Primary frequency response is the fastest type of frequency response pro-
 266 vided after a loss of generation. It must be released and ramped up to the
 267 required level within 10 s and then sustained for at least an additional 20 s.
 268 Secondary frequency response is released within 30 s and may be sustained
 269 for a further 30 minutes. Currently, both responses ancillary service are
 270 provided by coal, CCGT and hydropower plants [8].

271 2.3.3. Secondary, tertiary and time frequency control

272 Primary control actions are not designed to restore frequency to its target
 273 value without further action. Then, once primary frequency control has
 274 stabilised the frequency, secondary frequency is implemented to start bringing

275 the frequency back to its target value. Each plant participating will operate
276 within a certain range of power regulation that depends on its type.

277 In an interconnected system, the control of this response should be made
278 in a centralised way to avoid undesirable power flows on tie-lines which could
279 arise from compensation of changes in load or production in a different control
280 area. However, several hierarchical levels of centralised control may be used in
281 some systems, with a central coordinator dispatching control to the different
282 subsystems where secondary control is operated in a decentralised way [29].

283 Tertiary frequency control follows the same aims and principles as sec-
284 ondary frequency control but operates on a longer time scale. It is achieved
285 through different methods in the time frame of scheduling, such as (examples
286 from [5]):

- 287 • connection or tripping of power stations or loads on the reserve of the
288 tertiary control
- 289 • re-dispatch of generating units
- 290 • redistribution of secondary control generator output by adjustment of
291 the reference value of generated power
- 292 • changes in the power interchange program

293 These types of frequency control will not be considered in this study
294 which focuses on primary frequency control. Moreover, secondary frequency
295 control is not implemented on Great Britain's grid [24], so that only tertiary
296 frequency control is used to restore the frequency back to its target value.

297 For completeness, a different form of frequency control should be men-
298 tioned. Time frequency control, also known as *time error correction* or *elec-*
299 *tric clock time control*), is not used to ensure power quality but to ensure that
300 timing devices based on grid voltage cycles remain 'on time'. This is made
301 through adjustments of the system target frequency for long periods of time
302 (in the range of several hours) in order to keep the mean value of frequency
303 at 50 Hz [30]. Its necessity, however, is debated and it may disappear over
304 the next years [31].

305 2.3.4. *Dynamic Frequency Control Support*

306 Dynamic Frequency Control Support (DFCS) is a system implemented
307 on rather small island grid, such as some of the French islands, with low
308 inertia [32, 33]. It has very short deployment times (around 1 s) since it is

309 based on fast action from distributed energy storage systems. While tradi-
310 tional technologies were based on lead-acid or nickel cadmium batteries, the
311 development of advanced flywheels, faster lithium ion batteries, and ultra-
312 capacitors now provides faster response to match the short time scales [32].
313 This approach has already reached the megawatt scale in Hawaii with a test
314 system based on ultracapacitors [33, 34].

315 While some types of control are based on the same principle as the pri-
316 mary frequency control described in §2.3.1, they are only effective for small
317 speed droops of up to 1 or 2%. Another option is based on the frequency
318 time derivative, where power is released proportionally to the rate of change
319 of frequency, df/dt . This has been suggested to be more able to cope with
320 large disturbances, and has therefore been adopted in this study.

321 2.4. Contribution to frequency control from wind turbines

322 Wind turbines have demonstrated their potential to assist in frequency
323 control through adjustment of active power output and has become a re-
324 quirement in certain grid codes [35]. For example, Hydro-Québec (the TSO
325 of Quebec) has set stringent requirements for wind farms which should pro-
326 vide ‘at least the same inertial response as a power plant whose inertia (H)
327 equals 3.5s’ [36].

328 Power electronics based wind turbines can provide synthetic inertia to a
329 power system [20, 23, 37, 38, 39, 40, 41]. Contrary to synchronous or asyn-
330 chronous induction generators, a drop in frequency does not automatically
331 lead to kinetic energy being extracted from the rotor of wind turbines with
332 DFIG or FRC generators, and some control has to be implemented to mimic
333 the inertial behaviour by providing synthetic inertia. The typical inertia H
334 constant of a wind turbine lies in the range 2 – 6 s [38, 39], compared to 2 –
335 10 s for conventional generation as shown in table 3.

336 The most straightforward turbine action in frequency control is only avail-
337 able if there is a loss of load, or excess generation. In that case, the tur-
338 bine power output can be reduced through torque control by pitch adjust-
339 ment [41, 42, 43]. Even so, the provision of such frequency response depends
340 on the wind speed [43] and may therefore be complex to operate accurately.
341 Unless wind turbines are routinely operating at sub-optimal conditions, this
342 action is not a possibility in the converse case of loss of generation.

343 In the case of loss of generation, synthetic inertia can be released by
344 extracting kinetic energy from the rotor by controlling the output of the
345 inverter above the wind power input to the rotor, so that it would slow down

346 until the power output of inverter is lowered to a level equalling the rotor
347 wind power input). However, for wind speeds below the rated wind speed
348 of the turbine, the rotation rate of the rotor optimises the power output for
349 that wind speed. A reduction in rotor speed therefore leads to a reduction
350 in the efficiency and potentially substantial loss in power generation. This
351 loss may be as high as 40% of the power output when operating close to the
352 rated wind speed [44]. For that reason, this action may worsen the imbalance
353 more than it would actually help in restoring balance, and some TSOs are
354 reluctant to make use of this synthetic inertia. At wind speeds above the
355 rated wind speed, when turbines operate in limited torque mode to limit the
356 output from the generator, it is possible to override the torque limitation for
357 a brief period of time, so that the wind turbine generator provides power
358 above the rated power output [43].

359 One option for utilising the inertia of the rotor without necessarily going
360 too far below the optimum tip speed ratio is to operate the rotor at a rotation
361 rate above the optimal tip speed ratio. In that case, the kinetic energy of the
362 rotor could be used to provide temporary additional power and, at the same
363 time, increase the power conversion of the wind energy as the efficiency of
364 the rotor increases as the rotational speed gets closer to the optimal speed
365 [9, 41]. In this case, the wind turbine contributes both to the total system
366 inertia and to the primary frequency control.

367 3. Simulation model

368 To investigate the primary frequency response required to maintain the
369 grid frequency following normal loss of generation within the limits stipu-
370 lated by the UK grid code, a MATLAB/Simulink[©] was developed to solve
371 equations (2) modified by the self-regulation of load, eq. (5), and assuming
372 a power factor of around 1, $S_n = L_{sys}$, as

$$\frac{2H L_{sys}}{f_0^2} f \frac{df}{dt} = \Delta P \quad (7)$$

where ΔP is the difference between the generation and the system load. The
initial condition is $f(t = 0) = f_0$ and the generation is initially the balance
of base load generation, wind power output and the remaining frequency-
responsive generation less the normal loss of power (ΔP_n),

$$\Delta P(t = 0) = P_{base} + P_{fr} + P_{Wind} - \Delta P_n - L_{sys} = -\Delta P_n$$

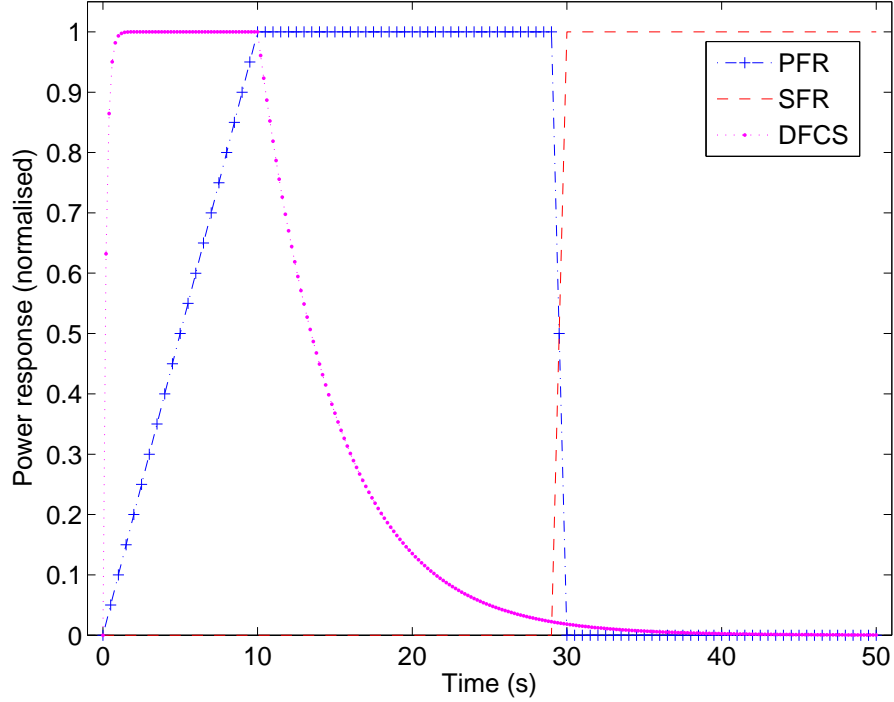


Figure 8: DFCS, PFR and SFR response models to a step change in frequency (Frequency change from 50 to 49.5 Hz at $t=0$, with full deployment of 1GW of DFCS, PFR and SFR).

As the simulation proceeds in time, this initial deficit in power is compensated by primary frequency response, \mathcal{P} , secondary frequency response, \mathcal{S} , and where included, dynamic frequency control support, \mathcal{D} , so that

$$\Delta P(t, f) = \Delta P(t = 0) + \mathcal{P}(t, f) + \mathcal{S}(t, f) + \mathcal{D}(t, f) - K_L \frac{f - f_0}{f_0} L_{sys}.$$

373 The forms of these three responsive actions are given in detail in the following
 374 section.

375 3.1. Model of frequency responses

376 The grid frequency model was initiated in a balanced state of a specified
 377 instantaneous load and wind penetration. At the time origin, $t = 0$, this
 378 state was perturbed by a sudden loss of generation of 1320 MW (normal

379 loss), followed by deployment of frequency response using PFR, SFR and, in
 380 some model settings, DFCS frequency response. The deployment strategy
 381 for these three responses are illustrated in figure 8 and described in detail in
 382 the following sections

383 3.1.1. Primary frequency response (PFR) model

384 Since the primary frequency reserve must be provided within $T_p = 10$ s of
 385 frequency drop and sustained for a further 20 s, it has been approximated by
 386 a linear increase from the time of loss of generation up to a target response
 387 within the first 10 s, followed by a constant response output until $T_f = 30$ s
 388 after the incident:

$$\mathcal{P}(f, t) = \begin{cases} \mathcal{P}_d(f) \times \frac{t}{T_p} & \text{if } t < T_p \\ \mathcal{P}_d(f) & \text{if } T_p \leq t < T_f \\ 0 & \text{if } t \geq T_f \end{cases} \quad (8)$$

389 with a target response action which is proportional to the frequency devia-
 390 tion, $f_0 - f$, up to all available power, P_{av} , utilised at the specified limit of
 391 $f_p = 49.5\text{Hz}$,

$$\mathcal{P}_d(f) = \begin{cases} 0 & \text{if } f \geq f_0 \\ \mathcal{P}_{av} \times \frac{f_0 - f}{f_0 - f_p} & \text{if } f_p < f < f_0 \\ \mathcal{P}_{av} & \text{if } f \leq f_p \end{cases} \quad (9)$$

392 3.1.2. Secondary frequency response (SFR) model

393 Since the secondary frequency reserve must be provided within 30 s of
 394 frequency fall and sustained for a further half an hour (which exceeds the time
 395 simulated by the model), it has also been approximated by a linear ramp-up
 396 which is activated during the primary frequency control period after a time,
 397 $T_s = 29$ s, and reaches full deployment, \mathcal{S}_d , at time $T_f = 30$ s, when all
 398 primary frequency control action is completed. Since our model does not go
 399 beyond the SFR time frame, we do not need to specify a maximum time for
 400 SFR deployment.

$$\mathcal{S}(Loss, t) = \begin{cases} 0 & \text{if } t < T_s \\ \mathcal{S}_d(Loss) \times \frac{t - T_s}{T_f - T_s} & \text{if } T_s \leq t \leq T_f \\ \mathcal{S}_d(Loss) & \text{if } t \geq T_f \end{cases} \quad (10)$$

401 The deployment strategy used in the model consists in releasing just enough
 402 SFR to ensure a quasi-steady state frequency of 49.5 Hz, so that :

$$\mathcal{S}_d(Loss) = \begin{cases} 0 & \text{if } Loss \leq 0 \\ Loss - K_L L_{sys} \frac{\Delta f_{max}}{f_0} & \text{if } 0 < Loss \leq 1,800 MW \\ \mathcal{S}_{req} & \text{if } Loss \geq 1,800 MW \end{cases} \quad (11)$$

403 This SFR released where \mathcal{S}_{req} is the maximum available SFR require-
 404 ment, dimensioned for compensation of an infrequent loss (1.8 GW) can be
 405 determined as [8]:

$$\mathcal{S}_{req} = \Delta P_i - K_L L_{sys} \cdot \frac{\Delta f_{max}}{f_0} \quad (12)$$

406 where $\Delta P_i = 1,800$ MW is the power imbalance after infrequent (as the worst
 407 case must be chosen here) loss of generation, L_{sys} the load on the system,
 408 and $\Delta f_{max} = f_0 - f_{min}$ is the maximum quasi-steady-state (QSS) frequency
 409 deviation allowed in response to the loss considered. This is shown in figure 9
 410 for the system characteristics investigated here.

411 3.1.3. Dynamic Frequency Control Support (DFCS) model

412 A DFCS system similar to that used for island grids with low inertia
 413 was also tested in this study to evaluate the potential reduction in primary
 414 frequency requirements. The power output through DFCS is modelled by:

$$\mathcal{D}(f, t) = \begin{cases} (1 - e^{-\frac{t}{\tau_u}}) \mathcal{D}_d(f) & \text{if } t < T_0 \\ e^{-\frac{t-T_0}{\tau_d}} \mathcal{D}_d(f) & \text{if } t \geq T_0 \end{cases} \quad (13)$$

415 where $T_0 = 10s$, $\tau_u = 0.2s$, $\tau_d = 5s$ and

$$\mathcal{D}_d(f) = \begin{cases} 0 & \text{if } R < R_{min} \\ \mathcal{D}_{av} \frac{R}{R_{max}} & \text{if } R_{min} \leq R \leq R_{max} \\ \mathcal{D}_{av} & \text{if } R > R_{max} \end{cases} \quad (14)$$

416 where the deployment of the DFCS reserve ($\mathcal{D}_{av} = 500MW$ is considered
 417 here) is controlled by the highest magnitude of the (negative) rate of change

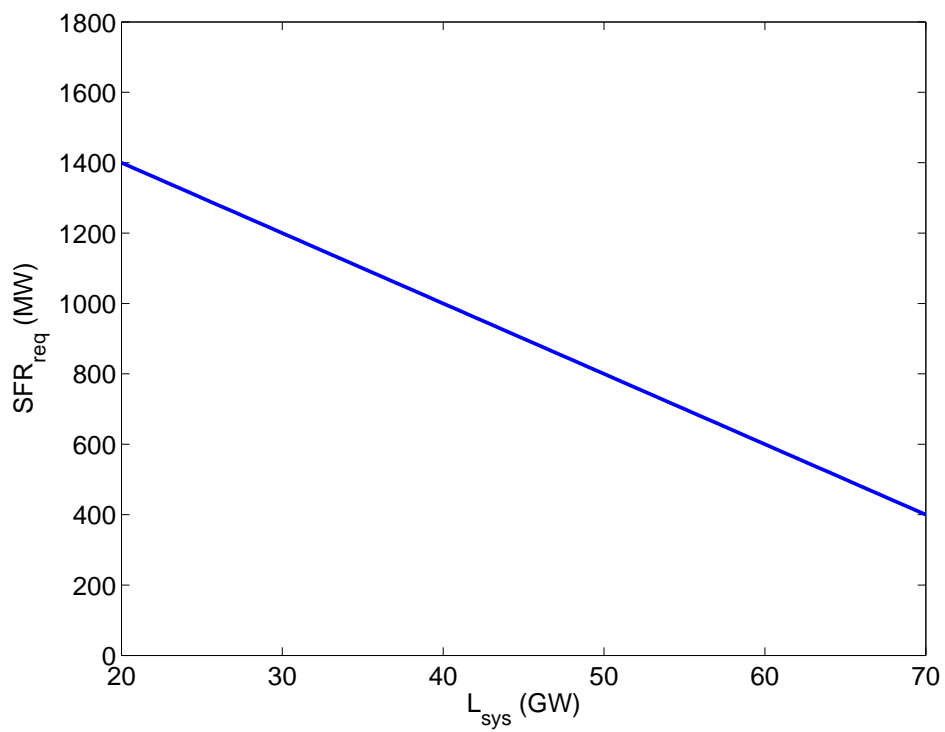


Figure 9: Variation of secondary frequency response requirements with load.

Table 4: Model parameters.

Parameter		Value	
System load	L_{sys}	20 to 70	GW
Wind power output	P_{wind}	0 to 50	GW
Base load generation	P_{base}	10	GW
Magnitude of normal loss	[14] ΔP_n	1,320	MW
Magnitude of infrequent loss	[14] ΔP_i	1,800	MW
Inertia	H		
- Non frequency responsive (base load)	[45] H_n	4	s
- Frequency responsive generation	[45] H_r	6	s
- Wind power inertia	H_w	none or 4	s
Load frequency sensitivity	[8] K_L	2	

418 of frequency during the frequency fall (within a band specified by R_{max} and
 419 R_{min}) :

$$R = \max(-df/dt) \quad (15)$$

420 The values used for the parameters were determined based on typical re-
 421 sponse times presented in the literature [32, 33] and empirical adjustments
 422 after some experience with the model and are listed in §3.2 for two DFCS
 423 scenarios presented here.

424 3.2. Model parameters and scenarios

425 The parameters used in the model are summarised in table 4. Only trans-
 426 mission connected capacity and transmission system load were considered in
 427 the current set up. While this is a limitation of the model for future sce-
 428 narios where substantial frequency response could be provided by embedded
 429 generation and micro-generation at the distribution level over the next years,
 430 this can be incorporated in a refinement of this model.

431 The model was used for a parametric analysis exploring the expected
 432 range of system load and installed wind capacity as listed in Table 4. A
 433 suitable balance of non-frequency responsive base generation, frequency re-
 434 sponsive conventional generation and wind power was analysed in terms of
 435 required frequency response generation to provide frequency control within

436 the stipulated constraints. With a base load of 10 GW, a physically meaning-
437 ful wind power output is the remainder up to the current load, with a limit set
438 at 50 GW. The corresponding frequency responsive conventional generation
439 at the beginning of the simulation is then $P_{fr} = L_{sys} - P_{base} - P_{wind} - \Delta P$.

440 To estimate the effect of wind power on the system frequency, three op-
441 tions of frequency control from wind power were explored in four scenarios:

442 **Scenario 1, standard frequency control:** Inertial control is implemented
443 in wind farms using $H = 4s$, which is a reasonable estimate for power
444 inertial capability which is stated to be in the range from 2 s to 6 s
445 [23, 38]. As this inertia time constant is the same as for the conven-
446 tional non-frequency responsive generation, this scenario can be seen
447 as the baseline. In this case, no DFCS is considered.

448 **Scenario 2, No frequency control from wind:** No inertial control is pro-
449 vided by wind turbines. No DFCS contribution is made.

450 **Scenario 3, Dynamic Frequency Control Support:** No inertial control
451 is provided by wind turbines but 500 MW of DFCS is installed to pro-
452 vide fast short-term response if the rate of change of the frequency at
453 the point of loss of generation exceeds $R_{min} = 0.0875\text{Hz/s}$ with a full
454 deployment of $\mathcal{D}_{av} = 500 \text{ MW}$ at $R_{max} = 0.35\text{Hz/s}$.

455 4. Results

456 This section presents the results of the simulation using the model devel-
457 oped above, the response requirements (PFR, SFR) under our scenarios are
458 developed together with an evaluation of the impact of implementing DFCS
459 on the amount of PFR needed. The model described in §3 was applied
460 with incrementally increasing available primary and secondary frequency re-
461 sponse, \mathcal{P}_{av} and \mathcal{S}_{av} respectively, until the frequency recovered sufficiently
462 to comply with the imposed limits (cf. 1.3). Figures 10 to 15 present the
463 results in the form of contour plots for pairs of Load and Wind power out-
464 put. Since there is always a base provision of $P_{base} = 10 \text{ GW}$, only pairs
465 with $L_{sys} \geq P_{base} - P_{wind}$ are physically valid situations, resulting in the
466 triangular shape seen in these figures. The missing contour lines near that
467 edge are a result of exploring the available space in steps of wind power and
468 system loads determined by the available computing resources.

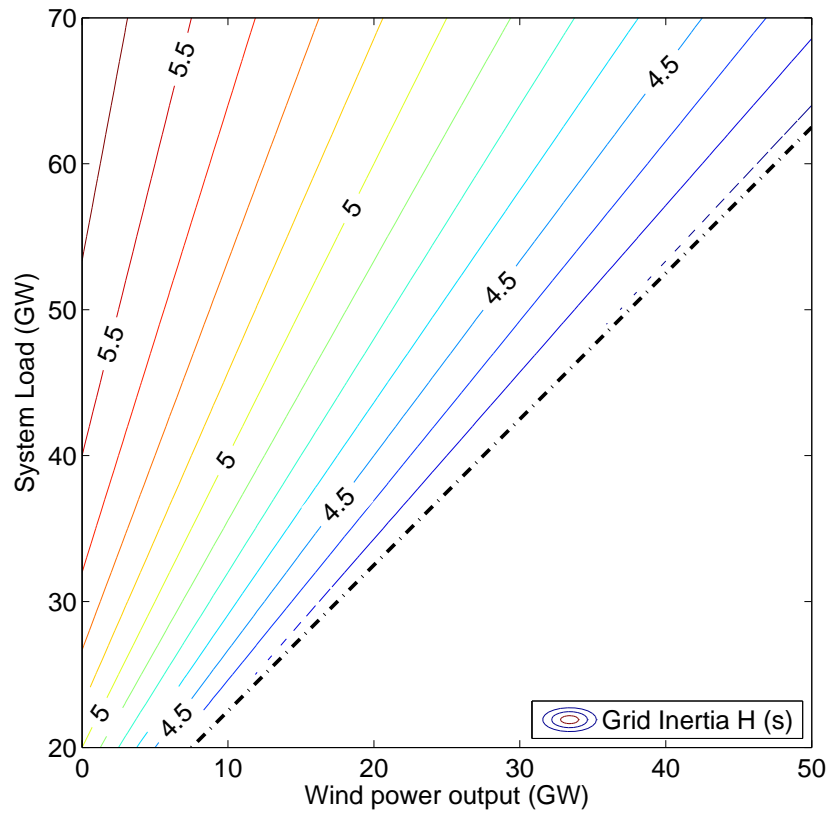


Figure 10: Scenario 1 - Grid inertia (H factor) variations with load and wind production.

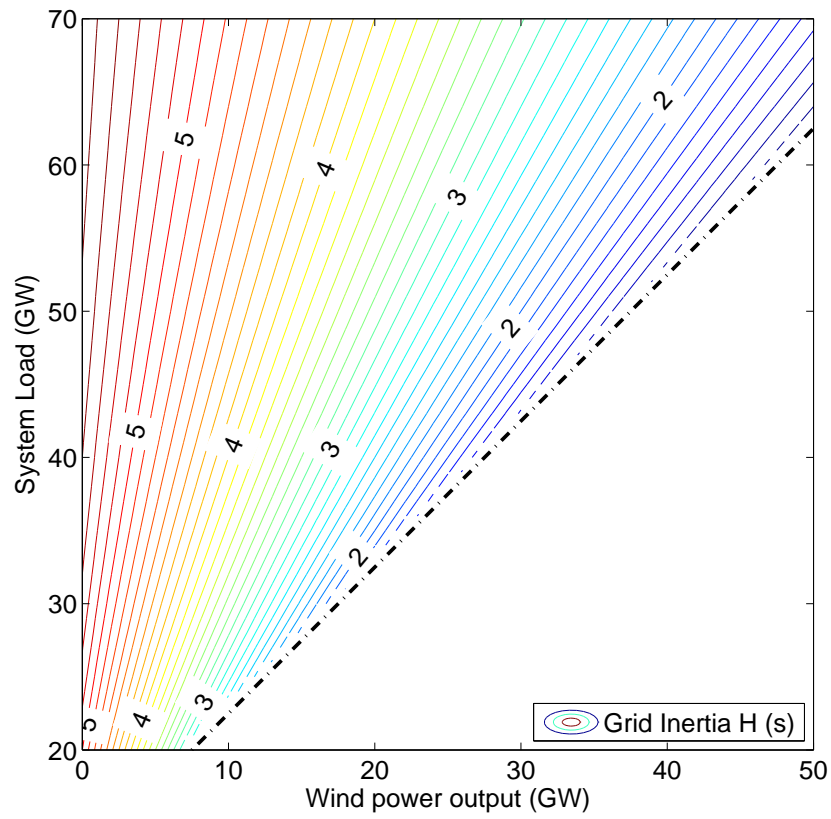


Figure 11: Scenario 2 and 3 - Grid inertia (H factor) variations with load and wind production.

469 *4.1. Evolution of inertia*

470 The values for H_{grid} , the grid inertia, were calculated using eq.(4) for each
471 of the scenarios, assuming that the apparent power can be approximated by
472 the load (i.e., power factor ≈ 1). The inertias for scenario 3 are identical
473 to those of scenario 2 at the same load and supply conditions since wind
474 turbines are not contributing to the inertia in either case. In scenario 1,
475 as shown on figure 10, the grid inertia (H_{grid}) varies in the range from 4
476 to 5.7 s decreasing as load decreases and/or wind increases, where at high
477 contribution from frequency responsive traditional generation (high L_{sys} and
478 low P_{wind}) approaches 6 s corresponding to H_r , the inertia from that type
479 of generation, while at high contribution from base generation and wind,
480 the inertia tends to 4 s, corresponding to their respective individual inertia
481 constants, H_n and H_w .

482 In scenarios 2 and 3, H_{grid} remains in the range between 4 and 6 s only
483 if the wind power contribution is less than around 25% of the system load.
484 For higher instant wind penetration, the grid inertia decreases progressively
485 to around 1 s when wind power has replaced most frequency responsive gen-
486 eration. This dramatic drop in inertia with increased instant penetration of
487 wind generation, will lead to a very high rate of change of frequency (RO-
488 COF) in the event of loss of generation, which justifies the study of DFCS
489 contribution.

490 *4.2. Primary frequency response requirements without DFCS*

491 The PFR requirement for the three scenarios is shown in figures 12 to
492 15, respectively. In the baseline scenario in figure 12, the need for PFR is
493 primarily determined by the system load, especially when the load is high.
494 This is seen by the almost horizontal contour lines. As the system load
495 reduces, the PFR requirement increases progressively from around 11 MW
496 at $L_{sys} = 70$ GW to over 3,000 MW when the system load is around 20 GW.
497 Once the wind power contribution is no longer a small contribution to the
498 supply, the PFR requirement also increases in line with the Wind power
499 contribution.

500 In scenario 2 in figure 13, when the wind turbines do not contribute to the
501 system inertia and the inertia therefore drops at high wind penetration, the
502 PFR requirement is affected much more strongly by the instant wind power
503 penetration. It not only rises to much higher levels, approaching 5 GW at low
504 system load, but the instant wind power penetration pushes the requirement
505 up much stronger.

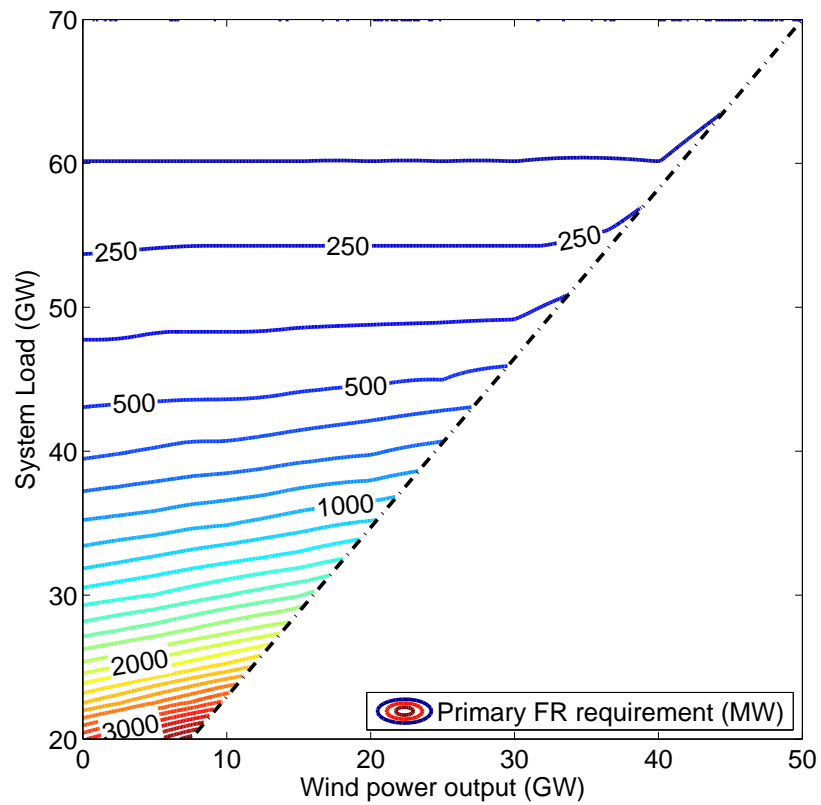


Figure 12: Scenario 1 - Variations of primary frequency response requirements with load and wind production (contour plot).

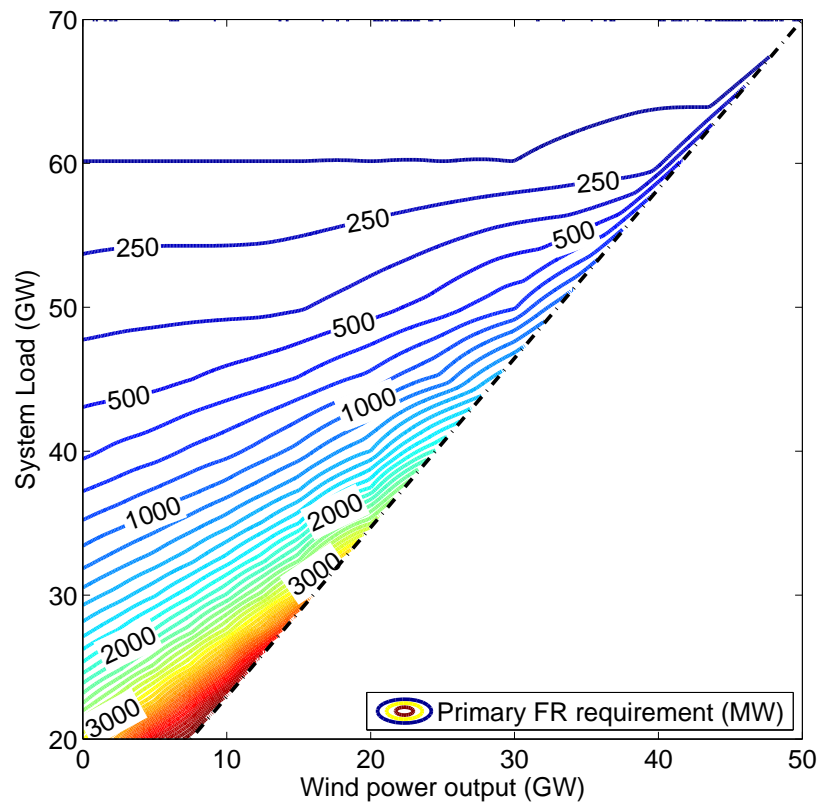


Figure 13: Scenario 2 - Variations of primary frequency response requirements with load and wind production (contour plot).

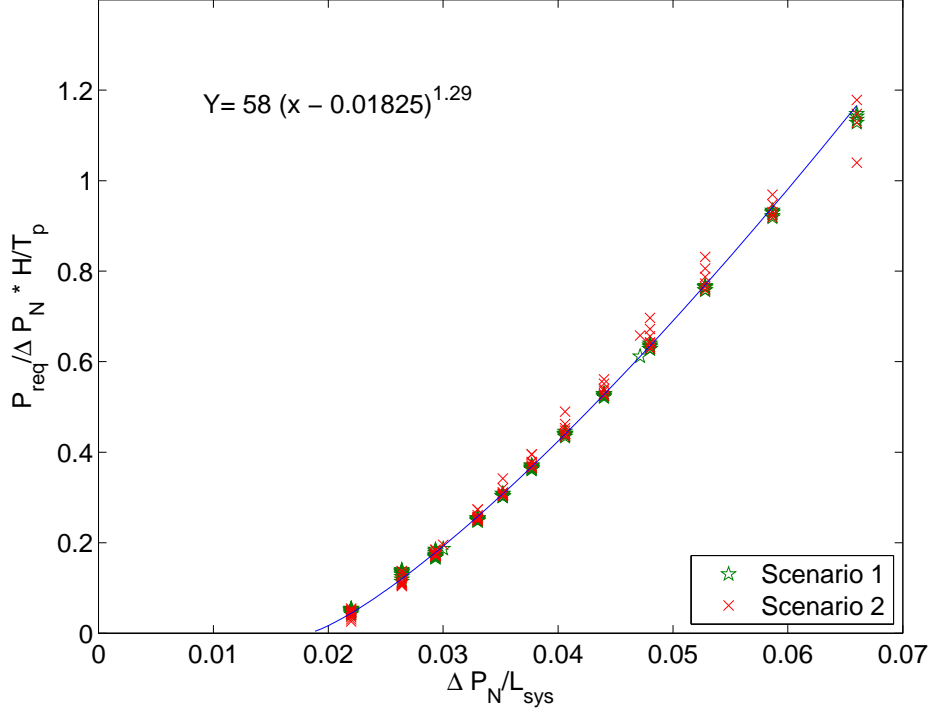


Figure 14: Primary frequency requirement for scenarios 1 and 2 in re-scaled variables of the product of PFR requirement with system inertia versus relative magnitude of loss of generation.

506 For example, while in scenario 1 a level of 1 GW PFR was required for
 507 a system load of 34 GW at no wind contribution, the level only rises to
 508 only 1.25 GW at 50% wind contribution to the same load. Conversely, a
 509 1 GW PFR reserve is sufficient for 50% wind penetration at a system load
 510 of 35 GW. That same PFR reserve of 1 GW operating in scenario 2 is only
 511 sufficient for 50% wind penetration when the system load exceeds 40 GW,
 512 while a 50% wind contribution at a system load of 34 GW requires a PFR
 513 reserve of 2 GW.

514 As the response strategy for scenarios 1 and 2 are identical but respond
 515 to systems with a different system inertia, there should be a single descrip-
 516 tion of the PFR requirement using suitably scaled variables. Guided by
 517 equations (4), (6), and the response strategy outlined in eq.(8), the PFR

518 requirement and the system load (as a representative of S_n) were both scaled
519 by the normal loss of generation (i.e. 1,300 MW) and the system inertia
520 was scaled by the response for reaching full deployment of the reserve, T_p in
521 eq.(8). Using these variables, it was found that both scenarios collapse onto
522 a common curve when the independent variable is the relative magnitude of
523 the loss of generation to the system load, $\Delta P_n/L_{sys}$, and the dependent vari-
524 able the product of the relative required reserve, $\mathcal{P}_{req}/\Delta P_n$, with the rescaled
525 system inertia, H/T_p , as shown in figure 14, where the green stars are for
526 scenario 1 and the red crosses for scenario 2.

527 Above a threshold value of the magnitude of loss of generation, the PFR
528 requirement increases with the proportion of the loss of generation to the
529 system load. This threshold value was determined from the data to be
530 0.0185 ± 0.0005 , meaning that the PFR reserve is only required when the
531 loss of generation exceeds approximately 1.85% of the system load. Above
532 that threshold, the requirement was found to increase slightly faster than
533 linear, where a linear regression of the form $\ln y = b + m(x - x_0)$ found the
534 best-fit curve as

$$\frac{\mathcal{P}_{req}}{\Delta P_n} = A \frac{T_p}{H} \left(\frac{\Delta P_n}{L_{sys}} - \Pi_0 \right)^q \quad (16)$$

535 with $A = 58 \pm 2$, $\Pi_0 = 0.01825 \pm 0.0005$, $q = 1.29 \pm 0.02$, and a correla-
536 tion coefficient of $r^2 = 0.991$. This line is shown as the solid blue line in
537 figure 14. As eq.(6) is inversely proportional to the system inertia, it is not
538 surprising that eq.(16) is inversely proportional to the system inertia. The
539 result that the PFR requirement rises faster than linear can be explained
540 by the fact that progressively more power is needed to not only make up
541 for the loss of generation but also to recover the frequency from the level
542 to which it had dropped before the PFR was fully deployed to a level from
543 where the secondary frequency control can return the system to its target
544 state. One would therefore expect that the exponent in eq.(16) will depend
545 on the response time of the frequency control actions and that a much earlier
546 or faster deployment of frequency control support could reduce the PFR re-
547 quirements especially when the loss of generation is a relatively large fraction
548 of the total generation. Equation (16) curve can now be used to benchmark
549 alternative frequency control strategies such as DFCS which is designed to
550 act very quickly.

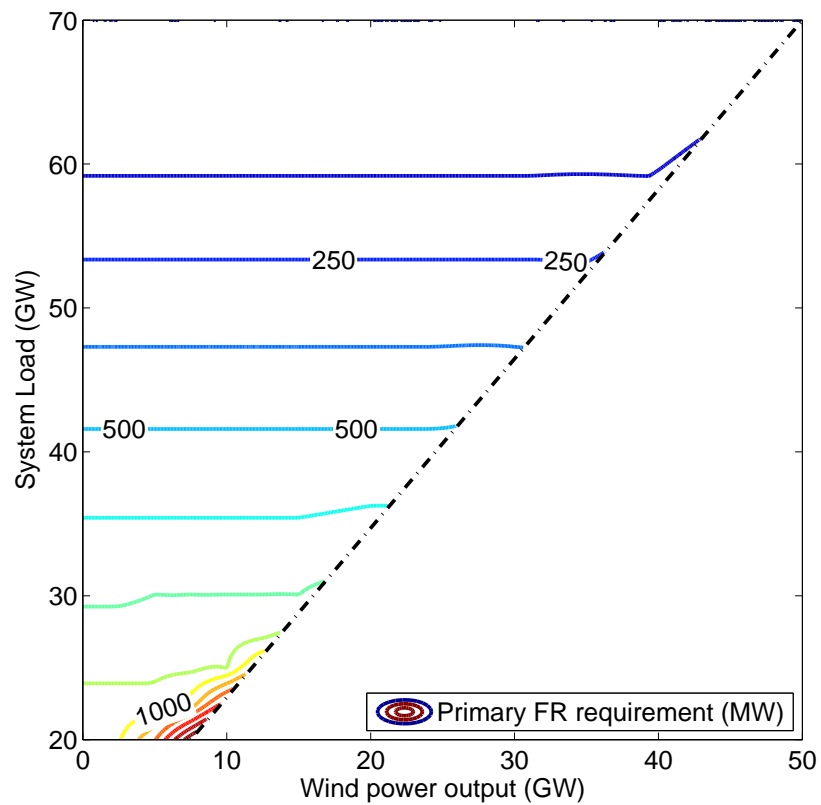


Figure 15: Scenario 3 - Variation of additional primary frequency response requirements in the presence of 500 MW DFCS against system load and wind production.

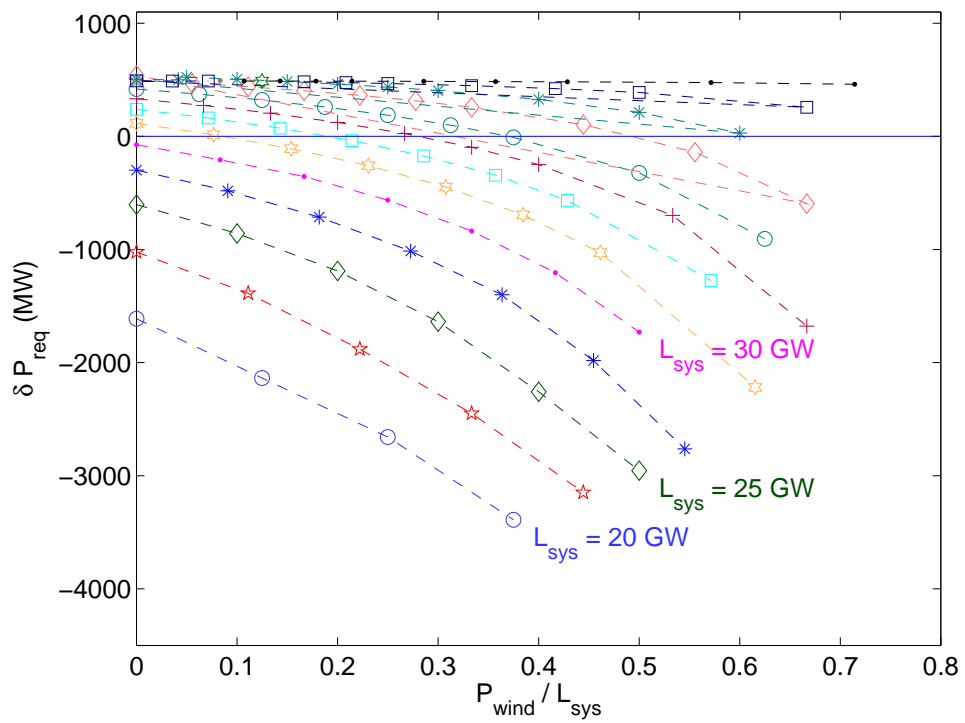


Figure 16: Scenario 3 - Change in total PFR requirement compared to benchmark against wind penetration.

551 *4.3. Dynamic Frequency Control Support*

552 To quantify if there is an actual reduction in overall PFR reserve require-
 553 ment compared to standard primary frequency control, the change in total
 554 PFR requirement against the benchmark from eq.(16) is shown in figure 16.
 555 Note that the total requirement for scenario 3 consists of the 500 MW DFCS
 556 and the additional PFR requirement from figure 15. At low system load, the
 557 activation of DFCS not only equals the standard PFR requirement – where
 558 the improvement jumps to the zero line at the first activation – but rapidly
 559 reduces the PFR requirements substantially.

560 These results demonstrate that DFCS has the potential to reduce the
 561 PFR requirement especially in cases where generation with no or little inertia
 562 contribute substantially to the total generation in situations when the loss
 563 of generation is a small percentage of generation ($\lesssim 4\%$).

564 The results for Scenario 3 are shown in figure 15, where two key features
 565 are clearly shown. Firstly, the deployment of the DFCS reserve at much
 566 smaller rate of change of frequency has removed the split between DFCS
 567 involvement and no benefit which was observed in scenario 3 and restricted
 568 the DFCS benefit to a small band. Secondly, the maximum additional PFR
 569 requirement is now substantially reduced not only compared to scenario 2
 570 (fig. 13) but even to scenario 1 (fig. 12) where the wind turbines fully con-
 571 tribute to the system inertia at the levels of conventional generators. Here,
 572 the maximum additional PFR is 1,240 MW at minimum load and maximum
 573 wind analysed compared to a PFR of 3,157 MW required under the same
 574 conditions in scenario 2 (and 3,567 MW in scenario 2). In these extreme
 575 conditions, the investment of 500 MW DFCS reserve is expected to be small
 576 compared to the savings in traditional PFR reserve requirements.

The overall benefit of DFCS in scenario 3 is shown in figure 17, where
 the change in total requirement (DFCS plus additional PFR) compared to
 the benchmark from eq.16) against that benchmark. Except for a small
 dead band where the benchmark requirement is near zero and the installed
 500 MW DFCS results in a constant offset, the results are fully consistent
 with a linear change with the benchmark requirement as

$$PFR_{req,DFCS} - \mathcal{P}_{req,0} = \mathcal{D}_0 + \mathcal{P}_0 - \tilde{m}\mathcal{P}_{req,0}$$

577 where the total PFR requirement consists of the sum of DFCS, \mathcal{D}_0 , and
 578 conventional PFR, \mathcal{P}_{req} , with $\mathcal{D}_0 = 500\text{MW}$, $\mathcal{P}_0 = 321 \pm 25\text{MW}$, $\tilde{m} = 0.810 \pm$
 579 0.011 , and a correlation coefficient of $r^2 = 0.986$ for the DFCS parameters

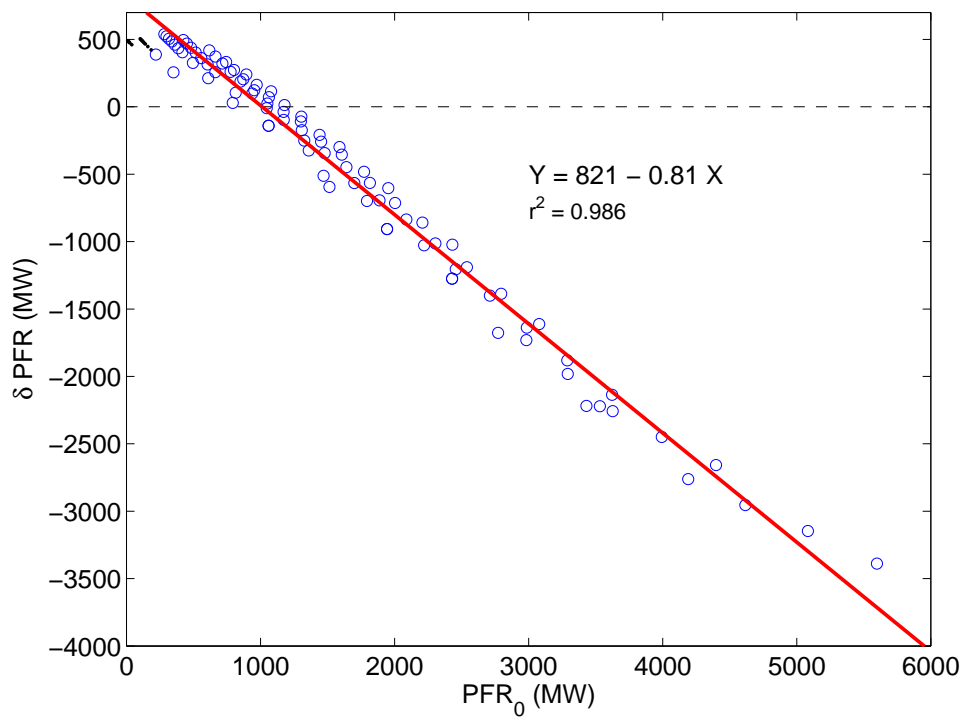


Figure 17: Scenario 3 - Change in total PFR requirement compared to benchmark against the benchmark.

580 used in Scenario 3. This can be rephrased in the additional traditional PFR
581 requirement as

$$\mathcal{P}_{req} = \mathcal{P}_0 + m\mathcal{P}_{req,0} \quad (17)$$

582 with $m = 0.190 \pm 0.011$. In that case, the use of 500 MW DCFS leads to
583 a net reduction in total primary frequency requirements from DCFS and
584 conventional resource combined when the conventional PFR requirement is
585 1,013 MW.

586 5. Discussions and conclusion

587 This study has shown that a dramatic increase in primary frequency
588 response requirements will be needed at low load levels with high wind pro-
589 duction unless inertial control of wind turbines or large scale DFCS system
590 is implemented in transmission networks of the size and nature as that of
591 Great Britain. As the response of the system frequency depends directly
592 on the system inertia and the speed with which it responds to changes in
593 frequency, the PFR requirements are equally determined by both the grid
594 inertia and the speed of response by the reserve.

595 The current model developed has a number of constraints ranging from
596 general explicit and implicit assumptions to the range of parameter values
597 investigated. It is important to keep these in mind when considering the
598 results of the study.

599 One of the fixed parameters was the presence of minimum base-load gen-
600 eration of 10 GW with an inertia of 4 s. This choice has excluded possible
601 future '100% Renewables' scenarios. While such scenarios are currently re-
602 mote, it would be useful to extend the parameter range to include them in
603 future work. In general, the model has simplified the actual generation mix
604 by only two types with representative values of their inertia as plant inertia
605 is confidential data for most of them in the UK. While this is a gross simpli-
606 fication, the result that the frequency behaviour following loss of generation
607 can be expressed as a function of the magnitude of the relative loss and total
608 system inertia alone, justifies this choice and is not expected to pose a serious
609 limitation to this model.

610 Similarly, a single response behaviour for all combined PFR had to be
611 assumed, and likewise for SFR and DFCS. The linear increase models for
612 PFR and SFR may oversimplify the problem. However, in a simple model
613 of generation with little data publicly available, they were considered as the

614 most appropriate for a first simple assessment. For a more precise assess-
615 ment, a model taking into account plant response through speed droop (by
616 plant type) and based upon potential instant mixes for power generation and
617 backup would be needed. This would actually increase the complexity of the
618 model and the data required much further (involving some commercially
619 sensitive data). A first step to investigate the actual need for such a model
620 refinement would be to assess the sensitivity of the results to the deployment
621 strategy in three particular steps; first by testing a slightly faster PFR de-
622 ployment (for example within $T_p = 8$ and 9 s rather than 10 s), secondly
623 by deploying faster than linear (e.g., proportional to $\sqrt{t/T_p}$) or slower than
624 linear (e.g., $\propto (t/T_p)^2$), and thirdly by splitting the currently single PFR
625 reserve into two kinds of plant with different inertia and response speed.

626 *5.1. Suggested evolution of the infrastructure*

627 Given the results of the study, there is an interest from both, an econom-
628 ical and environmental point of view, in studying the benefits from imple-
629 menting DFCS on a large scale in transmission systems with a more precise
630 model.

631 Given that the highest PFR requirement occur at low load, when the elec-
632 tricity spot price is low, the use of increasing the load by operating PHES
633 in pumping mode and by exporting through interconnectors is economically
634 attractive. If there is spare capacity in the reservoirs and demand from the
635 other networks on the interconnector, this would artificially increase the sys-
636 tem load and thereby reduce the PFR requirement. This poses the question
637 to be investigated separately, namely to assess whether current or potential
638 PHES energy capacities or interconnector demand are sufficient to provide
639 this service under current or expected low-load conditions.

640 Last but not least, as the wind capacity increases and the system develops
641 towards more sustainability, there will be a need for contribution from wind
642 turbines to frequency control (unless large scale DFCS is implemented). For
643 the UK grid, this is not ensured by the time of writing for two reasons; from
644 a UK market point of view, Renewable Obligations push wind generators to
645 produce as much as possible irrespective of the consequences; from a tech-
646 nological point of view or grid operation point of view, the current UK grid
647 code does not provide advanced specific requirements for wind farms and
648 relies on market structure for balancing services.

649 *5.2. Further considerations*

650 This study raised many questions for the future of frequency regulation
651 in power systems developing towards more sustainability and has identified
652 a number of investigations as immediate steps. In addition, the costs of dif-
653 ferent options should be investigated choose between large scale deployment
654 of DFCS, inertial contribution from wind turbines, or higher conventional
655 PFR requirements. For these options, environmental impacts, in particu-
656 larly greenhouse gas emissions, should also be assessed.

657 Another aspect that may require more research is the improvement in
658 load frequency response assessment and estimation, which as shown in [8]
659 would help to reduce both PFR and SFR requirements resulting in reduced
660 environmental impacts and expenses.

661 **Acknowledgements**

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