

1     **Utilisation of alkaline electrolysers in existing distribution**  
2             **networks to increase the amount of integrated wind**  
3                     **capacity**

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10

11     **Abstract**

12     Hydrogen could become a significant fuel in the future especially within the  
13     transportation sector. Alkaline electrolysers supplied with power from renewable  
14     energy sources could be utilised to provide carbon free hydrogen for future hydrogen  
15     filling stations supplying Hydrogen Fuel Cell Vehicles (HFCV), or Internal  
16     Combustion Engines (ICEs) modified to burn hydrogen. However, there is a need to  
17     develop and use appropriate strategies such that the technology delivers greater  
18     economic and environmental benefits.

19 In this work, the use of alkaline electrolyzers to increase the capacity of integrated  
20 wind power in existing radial distribution networks is explored. A novel optimisation  
21 approach for sizing, placement and controlling electrolyzers has been introduced,  
22 and its performance is assessed through modelling using a United Kingdom Generic  
23 Distribution System (*UKGDS*) case study. The controller objective is to dispatch  
24 alkaline electrolyzers appropriately to maximise the total amount of profit from selling  
25 hydrogen and reduce the losses within the network while considering the realistic  
26 characteristics of pressurised alkaline electrolysis plants and satisfying the power  
27 system constraints. The impacts of increasing wind power capacity or the initial size  
28 of hydrogen filling stations on the results have been investigated and discussed.

29

30 **Keywords:** Alkaline electrolyser; Renewable power; Active network management;  
31 Distribution network; Hydrogen station; Extended optimal power flow

32

33 **Nomenclature:**

34  $\theta^k$  is the  $n_b \times 1$  vector of voltage angles at the time interval of 'k'

35 *ANM* Active Network Management

36 *ASDL* Aggregate Station Demand Limit (MW)

37 *B* The set of bus numbers within the network

- 38  $C_i$  Cost function coefficients
- 39 *Capital* The capital cost of an electrolyser in £/MW
- 40  $D_i^k$  The amount of demand (excluding the demand of electrolysers) in MW on bus  
41 'i' of the last feeder (from bus 53 to bus 77) at the current time step 'k'
- 42  $\Delta E_{Loss}\%$  The percentage reduction in the total energy loss on the distribution  
43 network during the simulation
- 44 DER Distributed Energy Resources
- 45 DG Distributed Generator
- 46 DNO Distribution Network Operator
- 47 DSM Demand Side Management
- 48  $E_{HHV}$  is the Higher Heating Value (HHV) of hydrogen (39 kWh/kg, [1]).
- 49  $E_{Loss}$  Total energy loss during the simulation (MWh)
- 50  $E_{Loss}^{With}$  The total energy loss on the distribution network in the system with  
51 electrolysers (MWh)
- 52  $E_{Loss}^{Without}$  The total energy loss on the distribution network in the system without  
53 electrolysers (MWh)
- 54  $E_{St}$  The total energy delivered to all of the stations during the simulation (MWh)

55  $ELD_{ij}^k$  The demand (MW) of 'i'th active electrolyser located at 'j'th active filling station  
56 at the current time step ' $k$ '

57  $GA$  Genetic Algorithm

58  $H2P_{ij}^k$  Hydrogen produced by 'i'th active electrolyser located at 'j'th active hydrogen  
59 filling station (kg)

60  $HFCV$  Hydrogen Fuel Cell Vehicle

61  $|I_{ij}^k|$  The magnitude of current (A) flowing between bus 'i' and 'j' of the power  
62 system in the time interval of ' $k$ '

63  $|I_{ij}^{Lim}|$  The limit for the current magnitude (A) flowing between bus 'i' and 'j' of the  
64 power system

65  $ICE$  Internal Combustion Engine

66  $k$  The current time interval number in the simulations

67  $Life$  The lifetime of an electrolyser in years

68  $n_b$  is the number of busses within the network

69  $N_{El}^{EST}$  The number of electrolysers at each station

70  $NAEL_j^k$  The number of active electrolysers at active filling station 'j' at each time  
71 interval ' $k$ '

72  $NAS^k$  The number of active stations at the current time interval of ' $k$ '

- 73  $NB$  The number of branches on the power system
- 74  $NDP$  The number of data points during the simulation (e.g. if the simulation is  
75 carried out for a duration of 24 hours with time interval of 1 hour, then  $NDP=24$ )
- 76  $NS$  The total number of filling stations
- 77  $\eta_{ij}^k\%$  The efficiency of the 'i'th active electrolyser in the 'j'th active station in  
78 percentage
- 79  $NW$  The total number of wind farms placed within the network
- 80  $OM$  The annual operational and maintenance cost of an electrolyser in £/MW/year
- 81  $OPF$  Optimal Power Flow
- 82  $OSZ_i$  The optimal size of station 'i' in MW
- 83  $P_g^k$  is the active power (MW) from slack bus at the time interval of 'k'
- 84  $P_{Loss_i}^k$  The amount of power loss (MW) on branch 'i' of the power system at the time  
85 interval 'k'
- 86  $P_{Min.El}$  The minimum demand from an electrolyser to stay in active hydrogen  
87 production mode, and it is equal to the minimum demand of a station (MW)
- 88  $P_{N.El}$  The size (nominal demand) of each electrolysis unit located at each filling  
89 station (assumed to be 2 MW here).
- 90  $Q_g^k$  is the reactive power (Mvar) from slack bus at the time interval of 'k'

- 91  $S_{ij}^k$  The complex power flow (MVA) between bus 'i' and 'j' of the network in the  
92 current time interval of 'k'
- 93  $|S_{ij}^k|$  The apparent power (MVA) between bus 'i' and 'j' of the power system in the  
94 current time interval of 'k'
- 95  $|S_{ij}^{Lim}|$  The apparent power limit (MVA) between bus 'i' and 'j' of the power system
- 96  $SD_i^k$  The demand (MW) from station 'i' during the current time interval of 'k'
- 97  $SD^k$  is the  $NS \times 1$  vector of the demand (MW) from stations during the time interval of  
98 'k'
- 99  $S_{St}$  The initial size of each station (MW)
- 100  $Surplus(k)$  The surplus wind generation (MW)
- 101  $S_W^i$  Size of i<sup>th</sup> wind farm (MW)
- 102 **t** Metric tonne
- 103  $T$  The simulation time interval in hours (In this work  $T=1$  hour)
- 104  $TH2P$  The total hydrogen produced in metric tonne (**t**)
- 105  $TLB_{Prob}\%$  The probability of thermal limit violations (%)
- 106  $TLB_k$  The function indicating whether there has been any thermal limit violation  
107 within the grid at time interval 'k'

- 108  $\mathbf{V}_m^k$  is the  $n_b \times 1$  vector of voltage magnitudes at the time interval of 'k'
- 109  $|V_i^k|$  The magnitude of voltage on bus 'i' of the power system in pu in the current  
 110 time interval of 'k'
- 111  $|V_i^{Min}|$  The minimum limit for the voltage magnitude on bus 'i' of the power system  
 112 (pu)
- 113  $|V_i^{Max}|$  The maximum limit for the voltage magnitude on bus 'i' of the power system  
 114 (pu)
- 115  $VB_{Prob}\%$  The probability of voltage constraint violation (%)
- 116  $VB_k$  The function that indicates whether there has been any voltage violation  
 117 within the grid at time interval 'k'
- 118  $W_i^k$  The output of wind farm 'i' in MW at the current time step 'k'
- 119  $x^k$  is the optimisation vector at the time step 'k'

120

## 121 **1 Introduction**

122 There is a need to decarbonise the road transportation sector, and there are a  
 123 number of primary alternatives, such as battery electric vehicles or hydrogen fuel cell  
 124 vehicles (HFCVs), available for our clean future transport, which can replace the  
 125 conventional petrol or diesel Internal Combustion Engine (ICE) vehicles. Alkaline

126 electrolyzers can be used to produce 'green' hydrogen for HFCVs from electricity  
127 generated by renewable power resources [2].

128 On the other hand, the global capacity to generate wind power is continuously  
129 increasing [3], and the main issue arising from this increase is that the power  
130 systems might not be able to absorb the renewable power generated at all times due  
131 to lack of demand or breach of power network constraints. Transmission networks  
132 are already operating close to their capacity constraints, and adding renewable  
133 power generators at transmission level would require upgrading these networks with  
134 significant investment, so connecting generation to distribution networks has become  
135 more popular. As a result, there is a need to rethink about how to optimally arrange  
136 and operate the assets and devices on the distribution networks [4-6].

137 Distributed Energy Resources (DER) are generation technologies (typically  
138 renewable generation), energy storage technologies and flexible demand located at  
139 distribution level [4]. Current distribution networks have been designed on a 'fit and  
140 forget' basis, so some technical issues could arise due to adding more distributed  
141 renewable generation within the network. Such issues include voltage rises due to  
142 the connection of generators or reverse power flows, which could result in the  
143 violation of network constraints [7]. Therefore, there is a need to make distribution  
144 networks active by inclusion of responsive DER [8].

145 Active Network Management (ANM) techniques operate the network closer to its  
146 constraints by real time monitoring and controlling of the network parameters, such



147 as currents, voltages, Distributed Generator (DG) outputs and responsive or non-  
148 responsive load demands, and therefore their utilisation will allow more renewable  
149 power resources to be connected to the existing distribution networks while  
150 maximising the utilisation of network assets [9]. The current ANM techniques are  
151 listed in [9], which also includes load control and energy storage techniques to  
152 support increasing renewable power generation.

153 Different storage devices have been explained and compared in details in [10], [11]  
154 and [12], and their applications, advantages and drawbacks are explained in details.  
155 The benefits of energy storage devices from the Distribution Network Operator  
156 (DNO) point of view are listed below [13].

- 157 • Voltage support
- 158 • Distribution losses reduction
- 159 • Capacity support and deferral of distribution investment

160 Obviously, in addition to electrolysers, there are other options in the power system,  
161 such as batteries, fridges or pumped storage devices, which could be used for  
162 Demand Side Management (DSM) purposes, but they are limited, and they are not  
163 always available for participating in DSM. The other issue is that they might not be  
164 suitable for seasonal storage of electricity. However, hydrogen could be stored for a  
165 long period and used as clean fuel in the transportation sector. Therefore,  
166 electrolysers should be considered as one of the options to improve the operational  
167 performance of the electrical grid, especially, in the case that the grid has a high  
168 penetration of variable intermittent renewable power [14].

169 Most of the published papers in the area of hydrogen production with renewable  
170 power [15-19] make the assumption that the wind turbines or photovoltaic cells are  
171 physically close to the electrolysers, behind the meter, and they only export electric  
172 power to the grid when there is more power available from the renewable sources  
173 than can be absorbed by the electrolyser because it exceeds the electrolyser  
174 maximum power demand. The point is that in real practical applications the  
175 electrolysers, as used in fuel stations for example, are unlikely to be located adjacent  
176 to wind farms or photovoltaic generation plants. The situation is very different if they  
177 are not on the same bus behind the same meter, as the network operator has to deal  
178 with them separately, so there is a need to investigate other scenarios as well.  
179 Moreover, the published papers in this area do not address the problem of sizing or  
180 placement of electrolysers within power systems. This is an important problem as the  
181 benefits of energy storage devices are strictly dependent on their location, sizing and  
182 the control strategy to operate them. Importantly, no one has considered the actual  
183 measured characteristics of alkaline electrolysers so as to realistically model them in  
184 the context of power system operation.

185 Non-optimal connection of DER could potentially affect the quality of energy supply  
186 and damage power system equipment. It can also result in violation of the power  
187 system constraints [5]. Therefore, the optimal integration of DER is essential to make  
188 sure they would have a positive impact on the network operation. Some optimisation  
189 targets, from the DNO perspective, to integrate storage devices within the power  
190 system, are listed below.

- 191 • Finding the location and number of storage devices.
- 192 • Finding the size of storage to minimise capital costs [20].
- 193 • Finding the best load of storage during its operation to minimise the losses on
- 194 the power system while respecting the power system constraints (thermal and
- 195 voltage limits).
- 196 • Maximising renewable power integration.
- 197 • Minimising the costs of grid upgrade.

198 Solving such problem is usually addressed by using multi-objective optimisation  
199 methods [21].

200 Atwa and El-Saadany [22] have proposed a method to allocate energy storage in a  
201 distribution system with a significant penetration of wind power to maximise the  
202 benefits for the owner of DG and the utility operator. Their strategy tries to size the  
203 energy storage devices appropriately to avoid wind power curtailment and minimise  
204 the electricity bill. Their analysis compared the annual cost of different energy  
205 storage devices considering the total profit for both the utility and the DG owner.

206 Carpinelli et al. [13] have proposed a new cost-based optimisation strategy for the  
207 optimal placement, sizing and control of battery energy storage systems on the  
208 power system to provide different services such as loss reduction or reactive power  
209 provision. Their strategy minimises the whole system costs while considering the  
210 energy storage device profit from price arbitrage.

211 Celli et al. [21] and Carpinelli et al. [23] have proposed methods to optimally allocate  
212 energy storage on the distribution network to reduce losses and defer network  
213 upgrades using Genetic Algorithms (GAs). Their method finds the optimal charge  
214 and discharge pattern of energy storage devices using inner algorithms based on  
215 Dynamic Programming (DP) [21] and Sequential Quadratic Programming (SQP) [23],  
216 respectively.

217 Babacan et al. [24] have also used a Genetic Algorithm (GA) optimization method to  
218 reduce the voltage fluctuations caused by PV penetration through deploying battery  
219 energy storage systems, then they have conducted sensitivity studies to examine the  
220 behaviour of the method under varying sizing costs, siting costs and PV  
221 penetrations.

222 Mehmood et al. [25] have used a genetic algorithm multi-objective optimisation  
223 method to find the optimal location and size of battery energy storage systems with a  
224 view of increasing the lifespan of the batteries and regulating voltage in a distribution  
225 system with wind and solar generators.

226 Nick et al. [26] have worked on the problem of optimal siting and sizing storage  
227 systems within distribution networks to provide voltage support and reduce network  
228 losses using GA. Although their technique provides promising results, it is  
229 computationally expensive, and due to the non-convex and non-linear nature of the  
230 problem, finding the global optimal solution is not guaranteed.

231 An alternative approach to GA is Optimal Power Flow (OPF), which is a technique  
232 for optimal operation and planning of power systems [27]. Its aim is to optimise  
233 objective functions such as the amount of losses on the power system by setting  
234 some control variables in an optimal way while satisfying the demand and grid  
235 operating constraints [27]. The extended OPF formulation is a modified version of  
236 the standard OPF formulation, which includes additional variables, costs and/or  
237 equality and inequality constraints [28]. In this work, the utilisation of extended OPF  
238 will be investigated to size, place and control electrolyzers in power systems using a  
239 heuristic approach to avoid the complications of control strategies that use GAs.

240 The novelty of this work is in the strategy and algorithm used to size, place and  
241 control electrolysis hydrogen production stations within a distribution network so as  
242 to increase wind power capacity and network asset utilisation. The actual  
243 characteristics of pressurised alkaline electrolyzers, detailed in [29], are used for the  
244 first time to design a realistic control strategy to run them in the power system and  
245 find their impact on the electric network. The effectiveness of the proposed strategy  
246 is investigated through modelling using *MATLAB* software.

247

## 248 **2 Methodology**

249 In this section, a number of hydrogen filling stations with electrolyzers and wind  
250 farms will be added to a feeder of a radial distribution network. It is assumed the  
251 electrolyzers at the hydrogen filling stations will use some of the surplus wind power

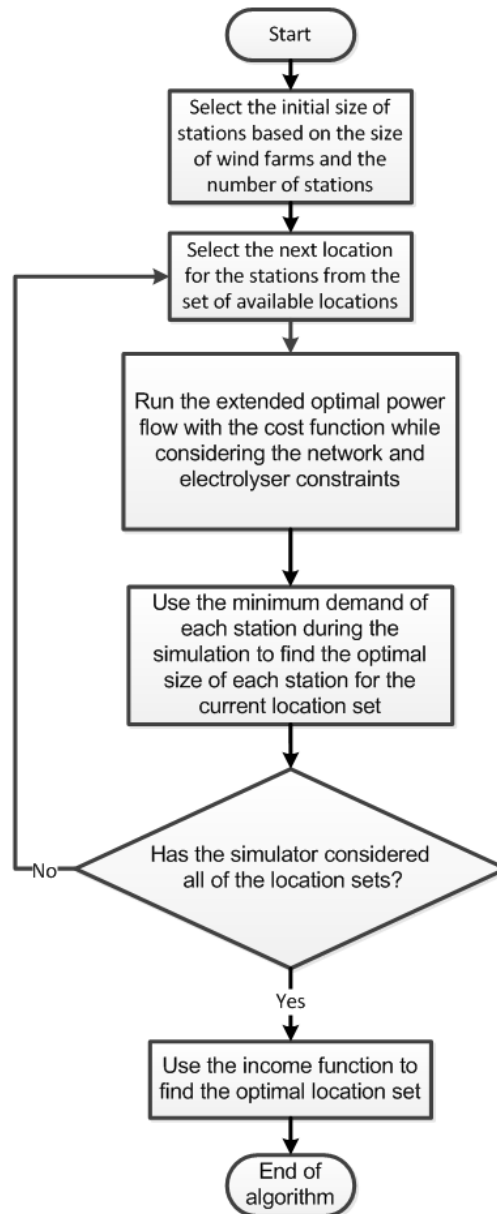
252 from wind farms to produce clean hydrogen for fuel cell vehicles in a future scenario ,  
253 e.g. next 20-30 years, where there is a significant penetration of HFCVs with a much  
254 more mature and developed hydrogen production and delivery infrastructure.

255 The electrolyzers in this system are assumed to be able to change their demands  
256 dynamically within their maximum and minimum demand limits. It is assumed that  
257 the Distribution Network Operator (DNO) owns and operates the electrolyzers, and  
258 there is a communication system between the (DNO) and each hydrogen filling  
259 station that allows adjustment of their electricity demand. The following optimisation  
260 steps are proposed to size, place and control these hydrogen filling stations within a  
261 feeder of a radial distribution network so as to maximise the utilisation of grid assets  
262 while respecting the power system constraints. The aim is to increase the local wind  
263 penetration whilst producing 'green' hydrogen for transport using alkaline  
264 electrolyzers.

- 265 1. A number of wind farms will be added to a feeder of a radial distribution  
266 network without any storage until they breach the power system constraints  
267 during the simulation period or require curtailment to meet the constraints.
- 268 2. A number of filling stations with electrolyzers will be added to the same feeder  
269 of the network. The stations will have a reasonable distance from each other  
270 and they will not be placed on the same buses as wind farms in order to  
271 reflect locational constraints. Each filling station will comprise a number of  
272 equally sized electrolyser units. The initial aggregate rating of filling stations  
273 will be chosen to be close to the aggregate rating of the wind farms. However,

- 274 after the simulation the minimum size of stations needed to satisfy the  
275 algorithm objectives and constraints will be identified.
- 276 3. An extended Optimal Power Flow (OPF) controller with a primary cost  
277 function will be used to minimise the electricity demand of the filling stations  
278 and distribution losses at each time step while satisfying the power system  
279 constraints. The reason to minimise the demand of each station is to minimise  
280 the final size (hence the capital costs) of each station. The electrolyser  
281 characteristics identified in [29] will be used in the optimisation process. The  
282 electricity demand of each station will be determined by the optimisation  
283 algorithm, and then the demand of each individual electrolyser making up a  
284 station will be determined by a local controller at each filling station.
- 285 4. After running the simulation for a duration of a year, the maximum electricity  
286 demand of each station during the simulation will be used to determine its  
287 optimal rating.
- 288 5. The location of the hydrogen stations on the feeder will be varied and then the  
289 above steps (3 and 4) will be repeated to find the best solution to minimise the  
290 size of stations and network losses while maximising the profit from selling  
291 hydrogen according to an 'income' function.

292 Fig. 1 summarises the heuristic optimisation algorithm proposed in this work to size,  
293 place and control electrolysis hydrogen filling stations within a radial distribution  
294 network.



295

296 *Fig. 1 The algorithm used to size, place and control the hydrogen stations*

297 The proposed strategy can also be utilised while placing solar farms in the power  
 298 system. However, in this work only wind farms are added to the system.



299 It should be noted that the main goal of this work is not to just talk about the benefits  
300 of energy storage in the distribution network. The owners of HFCVs have already  
301 paid the price of their cars, and that cost is not being paid by the owner of the  
302 distribution network or the investors in the filling stations. Therefore, the proposed  
303 scenario is very different from the case of just adding storage devices in the power  
304 system to improve its performance from both investment and energy efficiency point  
305 of views.

306 After the simulation, the results of currents and voltages and distribution losses  
307 before and after adding hydrogen filling stations will be compared to assess the role  
308 of electrolysers in improving power system operation. In the cases that the voltage of  
309 busses or flow of the branches are out of limits, the probability of voltage violations  
310 or overload in different scenarios will be compared.

311

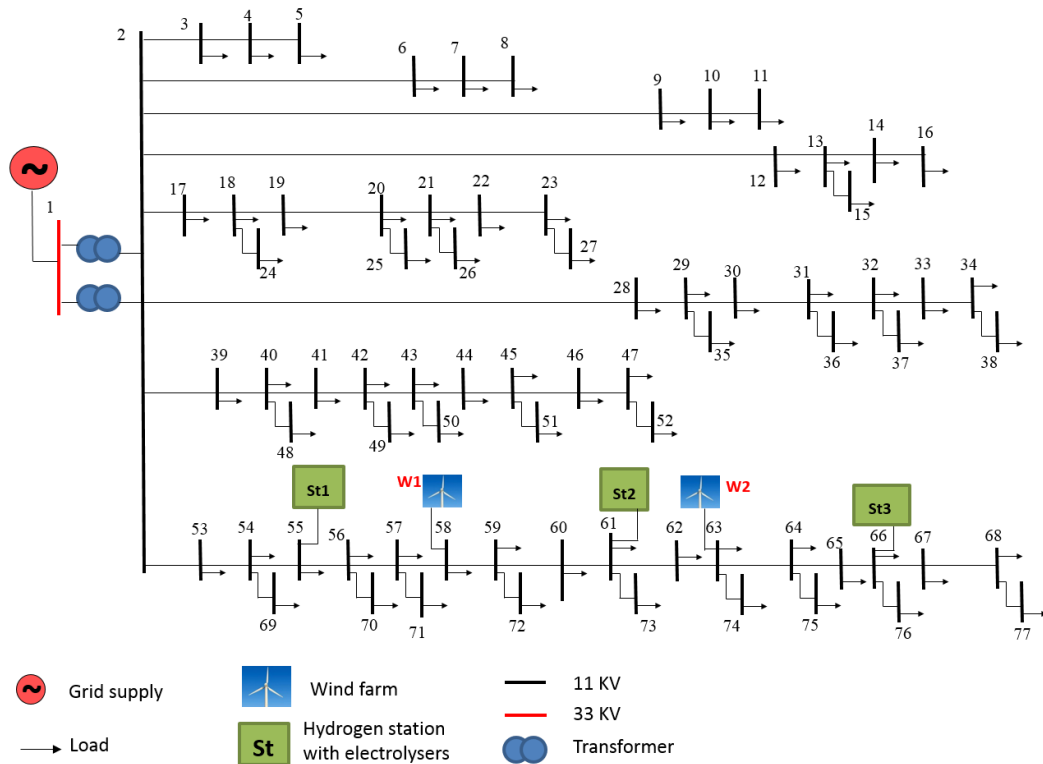
### 312 **3 Modelling details**

313 The United Kingdom Generic Distribution System (*UKGDS*) is a resource for  
314 simulation and analysis of the impact of distributed generation on the UK power  
315 network. The models represent the most common architectures used by the UK  
316 Distribution Network Operators (*DNOs*), but they are slightly altered to facilitate  
317 testing and evaluation of new concepts [30].

318 A radial distribution network is used as a case study in this work to evaluate the  
319 effectiveness of the proposed strategy. This type of network is used, as it is much

320 easier to consider the distance of stations from each other while placing them on the  
321 network. In real life, it is not very useful to put the filling stations on every node of the  
322 power system and then run the optimisation process, which might lead to cases of  
323 having some filling stations very close to each other, and on the other hand, having  
324 some areas not covered by any nearby hydrogen filling station. Therefore, a radial  
325 distribution network will best suit the aim of the work in this work to show the  
326 effectiveness of the control strategy. A *UKGDS* phase one High Voltage (*HV*)  
327 Underground (*UG*) network [30] is used in this study.

328 Software was developed by the author using *MATLAB* and *MATPOWER* [28] to  
329 simulate the proposed scenarios applied to the *UKGDS* model. Fig. 2 shows the  
330 network used in this study, with added hydrogen filling stations and wind farms.



331  
332

Fig. 2 UKGDS HV UG network with wind farms and hydrogen filling stations

333 The aggregate total demand on the UKGDS HV UG network is 24.2 MW [30], so the  
 334 electricity demand profile for the United Kingdom [31] is scaled down to match to the  
 335 load profile of this UKGDS system, and then it is used in the simulation process. It is  
 336 assumed that the loads on each node of the power system are constant during each  
 337 simulation time interval. The amount of demand at different system nodes is equal to  
 338 the proportion of loads defined in the UKGDS load profile.

339 In this work, the hydrogen stations and wind farms are modelled on only one feeder  
 340 of the system (feeder number 8, which is the last one) to assess the performance of  
 341 the proposed control strategy. The filling stations are added on three buses, and the  
 342 wind farms are added at bus 58 and 63 of the UKGDS model. Table 1 contains the

343 location of each hydrogen filling station proposed for each simulation scenario. The  
344 location of each station in each of the five sets is selected in a way that the stations  
345 have a reasonable distance from each other, and they are not placed on the same  
346 bus as the wind farms.

347

348 *Table 1 The location of hydrogen filling stations in each set*

Set number/station location	Station bus number		
	Station 1	Station 2	Station 3
Set 1	53	59	64
Set 2	54	60	65
Set 3	55	61	66
Set 4	56	62	67
Set 5	57	64	68

349

350 To scale the wind farms to the *UKGDS* model and cause a violation of power system  
351 constraints without utilisation of electrolysers, their nominal generation capacity was  
352 selected to be 10 MW. Table 2 also shows the location and size of wind farms used  
353 in this work.

354

*Table 2 Wind farm location and size*

	Location (bus number)	Capacity (MW)
Wind farm 1	58	10
Wind farm 2	63	10

355

356 Wind speed data with resolution of one hour from two UK regions (Tain Range and  
357 Peterhead [32]), which was obtained from the UK meteorological office for the  
358 duration of one year, was used in the analysis. For simplicity, it is assumed that the  
359 wind turbines used in the wind farms are of the same type and with the same rating,  
360 and they have a power curve of a 2 MW wind turbine made by Repower, [33]. Using  
361 the wind speed data, the turbine power curve and the rated size of wind farms in  
362 Table 2, the output of each wind farm during a year was calculated with a time  
363 resolution of one hour.

364 To select the initial size of stations, the following assumptions were made.

- 365 • The initial size of each station is an integer multiple of 2 MW which is the  
366 assumed size of each electrolyser.
- 367 • The initial size of all the stations are equal (i.e. they have the same number of  
368 electrolyser units).

369 • The aggregate nominal demand of stations is chosen to be as close as  
370 possible to the aggregate capacity of wind farms.

371 Based on these assumptions, the following equation is used to find the initial size of  
372 each station ( $S_{St}$ ) in MW. The 'Round' operator is used to make sure the initial  
373 proposed size of each station is an integer multiple of the size of each electrolyser.

$$374 \quad S_{St} = Round \left( \frac{1}{NS * P_{N.El}} * \sum_{i=1}^{NW} S_W^i \right) * P_{N.El} \quad (1)$$

375 By inserting the corresponding values in Eq. (1) the initial size of each station was  
376 found to be 6 MW.

377 The number of electrolysers at each station ( $N_{El}^{EST}$ ) can be calculated from the  
378 following equation.

$$379 \quad N_{El}^{EST} = \frac{S_{St}}{P_{N.El}} \quad (2)$$

380 This means that 3 electrolysers with a rating of 2 MW are located at each station at  
381 the start of the simulation in this first case study.

382 Two scenarios are considered in the simulations. In the first scenario, the system  
383 only has two wind farms without any electrolysers, and the fluctuation in the  
384 difference between the local generation and demand must as far as possible be  
385 compensated by import/export of power from the distribution substation. In the  
386 second scenario, electrolysers are also operating in the system to capture some of  
387 the surplus wind power generated within the feeder to alleviate the problems caused

388 by the distributed wind generation within the network. The assumptions and strategy  
 389 used in the second scenario to operate the electrolyzers is explained below.

390 It is assumed that the demand of each station is controllable from the distribution  
 391 network control centre. It is also assumed that each electrolyser behaves like a linear  
 392 load consuming only active power within its acceptable operational range. The  
 393 minimum demand of each electrolyser is assumed to be equal to 20% of its nominal  
 394 demand.

395 A cost function ( $Cost(k)$ ) is defined to minimise the electricity demand from stations  
 396 and also the losses within the distribution system.

$$397 \quad Cost(k) = C_1 * T * \sum_{i=1}^{NS} SD_i^k + C_2 * T * \sum_{i=1}^{NB} P_{Loss_i}^k \quad (3)$$

398 The objective of the optimisation is to find the optimisation vector  $x^k$ , which includes  
 399 the optimisation variables, to minimise 'Cost' (£) at each simulation time step.

$$400 \quad x^k = \begin{bmatrix} \theta^k \\ \mathbf{V}_m^k \\ P_g^k \\ \mathbf{SD}^k \\ Q_g^k \end{bmatrix} \quad (4)$$

401 The capital, operational and maintenance (OM) costs, in addition to, lifetime of  
 402 alkaline electrolyser taken from [34] are used to find  $C_1$  in £/MW/h. It is assumed that  
 403 annual OM costs of an electrolyser is equal to 2% of its capital costs.

$$404 \quad C_1 = \frac{Capital}{Life * 365 * 24} + \frac{OM}{365 * 24} = \frac{1480,000}{20 * 365 * 24} + \frac{1480,000 * 0.02}{365 * 24} = 11.82 \text{ (£/MW/h)} \quad (5)$$

405  $C_2$  is the cost of electricity loss and selected to be £35/MWh [35].

406 There are some limits on the demand of stations and power system constraints that  
407 should be respected during the optimisation process. Before detailing those limits,  
408 some additional variables are defined here.

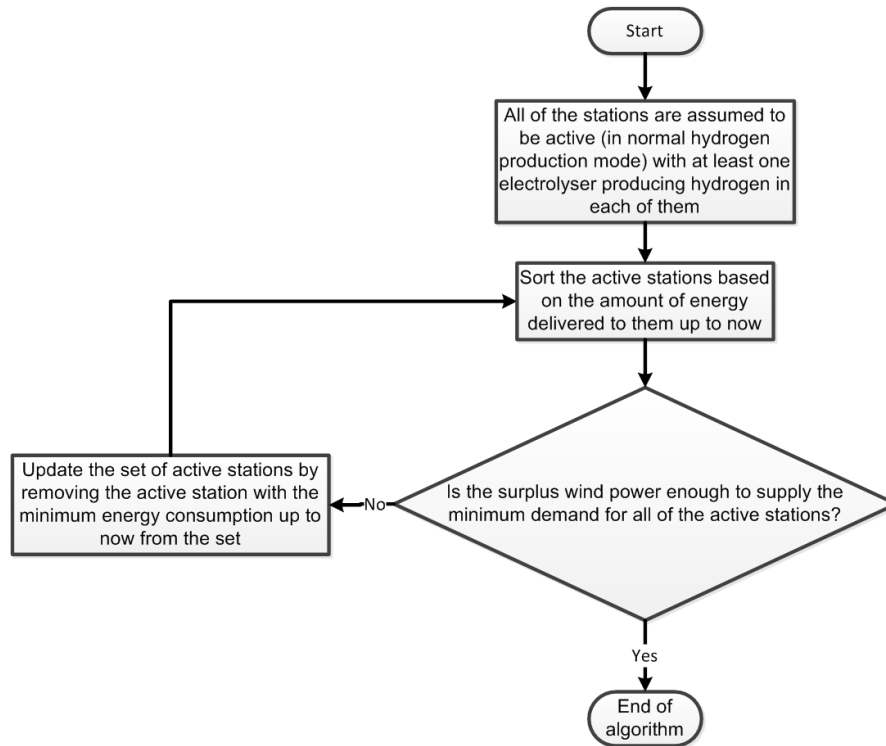
409 The surplus wind power on the last feeder of the network can be calculated from the  
410 following equation. The controller needs to know the amount of wind generation and  
411 non-electrolysis demand on each bus of the feeder at each time step in order to  
412 calculate the surplus wind generation.

$$413 \textit{Surplus}(k) = \sum_{i=1}^{NW} W_i^k - \sum_{i=53}^{77} D_i^k \quad (6)$$

414 If, at a given time step, the surplus power is not sufficient to supply the minimum  
415 demand for all of the stations (i.e. to keep at least one of their electrolyzers in  
416 hydrogen production mode), then the stations with least energy delivered to them up  
417 to the current time step will be selected to be removed from list of active stations and  
418 their demand will be assumed to be zero. This decision is taken to make sure that  
419 the stations which have received more energy during the simulation will be more  
420 likely to stay active (produce hydrogen) and continue providing service to improve  
421 the performance of the power system, and the stations which have had lower  
422 demand in the previous time steps and are more likely to have less impact on the  
423 improvement of the results become deactivated when there is not enough surplus  
424 power within the system. Fig. 3 shows the algorithm used at each time interval to  
425 choose which station is active and which stations do not have any active



426 electrolyzers if the surplus wind power is not sufficient to provide the minimum  
427 demand for all of the stations.



428

429 *Fig. 3 The algorithm used at each time interval to update the supplied stations*  
430 *(active stations) when there is lack of surplus power for all of the stations*

431

432 The 'Surplus' value could become negative at some points when the aggregate wind  
433 power generation is below the aggregate local non-electrolysis demand. Therefore  
434 another variable called 'Aggregate Station Demand Limit' (*ASDL*) is defined to be  
435 used as the limit in the simulations to make sure the aggregate demand from the

436 local hydrogen stations does not exceed the surplus wind (in the case that the  
 437 surplus wind is positive), and therefore avoid conditions that hydrogen is produced  
 438 using power from conventional plants, which would introduce unwanted carbon  
 439 dioxide emissions into the energy supply chain of the hydrogen. In addition, when  
 440 the '*Surplus*' value is negative, the hydrogen stations should not consume any  
 441 power.

$$442 \quad ASDL(k) = \max(Surplus(k), 0) \quad (7)$$

443 *ASDL* will always have a non-negative value. This means that if '*Surplus(k)*' is  
 444 positive then *ASDL(k)* will be equal to *Surplus(k)*, but if *Surplus(k)* is negative, then  
 445 *ASDL(k)* will be equal to zero.

446 The limits for the aggregate demand of the active stations are defined by the  
 447 following equation.

$$448 \quad NAS^k * P_{Min.El} \leq \sum_{i=1}^{NS} SD_i^k \leq ASDL(k) \quad (8)$$

449 The following limit will also be applied to the electricity demand of each active  
 450 station, as the minimum demand of one station will be equal to the minimum demand  
 451 of one electrolyser.

$$452 \quad P_{Min.El} \leq SD_i^k \leq S_{St} \quad (9)$$

453 The constraints of the power system should be respected during the optimisation  
 454 process.

455 Apparent power constraints:

$$456 \quad |S_{ij}^k| \leq |S_{ij}^{Lim}| \quad \forall i, j \in B \quad (10)$$

457 Voltage constraints:

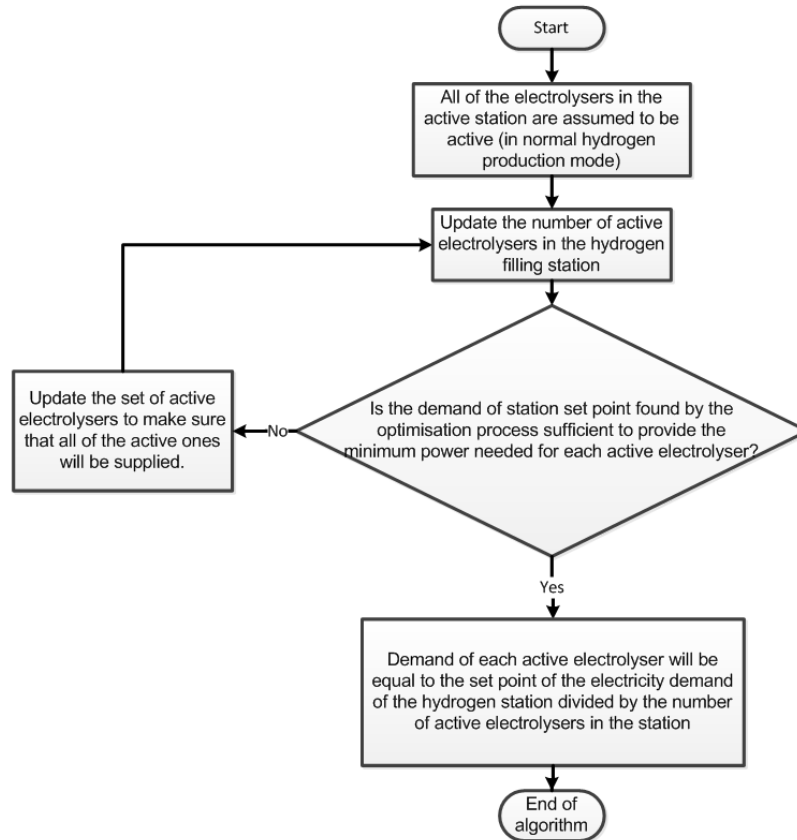
$$458 \quad |V_i^{Min}| \leq |V_i^k| \leq |V_i^{Max}| \quad \forall i \in B \quad (11)$$

459 The voltage variation limits in the *UKGDS* network are  $\pm 3\%$  of the nominal nodal  
460 voltage, [30]. In this study, the power system limits, taken from [30], are assumed to  
461 be constant during the whole year.

462 After running the simulation and finding the optimal demand of each station at each  
463 time step, the distribution network control centre can send the demand set-point of  
464 each station to the local station controllers, which are responsible to operate  
465 individual electrolyzers according to their operational status and constraints. Fig. 4  
466 shows the algorithm used at each time interval to select the number of active  
467 electrolyzers (electrolyzers in hydrogen production mode) and their demand at each  
468 active station.

469 The objective of this algorithm is to keep as many electrolyzers as possible in  
470 hydrogen production mode to maximise the efficiency of hydrogen production in  
471 each filling station. The controller selects the number of active electrolyzers ( $NAEL_j^k$ )  
472 at active filling station 'j' at each time interval 'k' using the following equation.

$$473 \quad NAEL_j^k = \min \left( \left\lfloor \frac{SD_j^k}{P_{Min.El}} \right\rfloor, N_{El}^{EST} \right) \quad \forall (1 \leq j \leq NS, j \in \mathbb{N}) \quad (12)$$



474

475 *Fig. 4 The algorithm used to select the number of active electrolyzers and their*  
 476 *demand at each active station*

477

478 The ‘min’ operator is used to make sure that the number of active electrolyzers in  
 479 each active station at each time interval is not bigger than the total number of  
 480 electrolyzers at each station ( $N_{EL}^{EST}$ ). The ‘floor’ operator ( $\lfloor \ \rfloor$ ) is used to make sure  
 481 that demand set-point of each active station is sufficient to provide the minimum

482 demand of each active electrolyser located in the station all the time ( $NAEL_j^k$  \*

483  $P_{Min.El} \leq SD_j^k$ ).

484 To calculate the amount of hydrogen production in each station, an efficiency curve  
485 must be used for the electrolysers operating at each station. The efficiency curve of  
486 electrolysers depend on their design, but to calculate the amount of hydrogen  
487 production in this work, it is assumed that all of the electrolysers operating in the  
488 filling stations have a linear efficiency curve. These electrolysers have their  
489 maximum energy efficiency of 80% when they operate at their minimum demand  
490 (20% of nominal demand), and a minimum efficiency of 65% when they are  
491 operating at their maximum demand. It is assumed that the efficiency of the rectifier,  
492 Faraday efficiency and Balance of the Plant (BOP) of the electrolyser were  
493 considered in the electrolyser efficiency curve. In addition, it is assumed that the  
494 operating temperature and pressure of the electrolyser will remain constant during  
495 the simulation.

496 The controller gives the same amount of power to each active electrolyser in each  
497 station. This means that the hydrogen production system will operate with the  
498 maximum efficiency because the electrolysers will consume the minimum possible  
499 power at all times. Therefore, the demand of 'i'th active electrolyser ( $ELD_{ij}^k$  in MW)  
500 located at 'j'th active filling station can be calculated using the following equation.

501 
$$ELD_{ij}^k = \frac{SD_j^k}{NAEL_j^k} \quad \forall (1 \leq i \leq NAEL_j^k, 1 \leq j \leq NS, i, j \in \mathbb{N}) \quad (13)$$

502 Using the electrolyser efficiency curve and the above equation, the amount of  
 503 hydrogen produced ( $H2P_{ij}^k$  in kg) by 'i'th active electrolyser at 'j'th active hydrogen  
 504 filling station can be found using the following equation.

$$505 \quad H2P_{ij}^k = \eta_{ij}^k * \frac{ELD_{ij}^k * T * 1000}{E_{HHV}} \quad \forall (1 \leq i \leq NAEL_j^k, 1 \leq j \leq NS, i, j \in \mathbb{N}) \quad (14)$$

506

#### 507 **4 Simulation results and discussions**

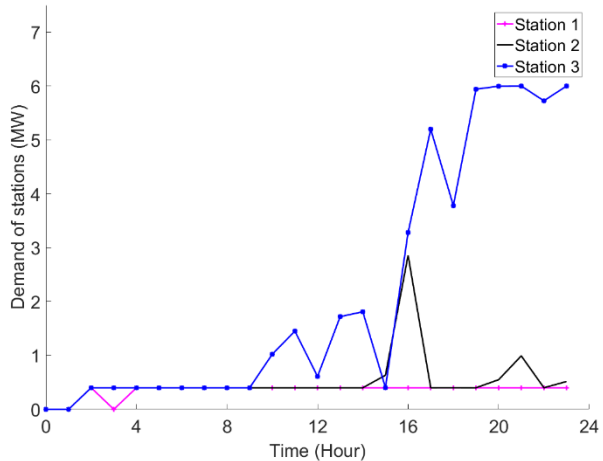
508 This section contains the results of running the simulation for a duration of 24 hours  
 509 and a year using an extended OPF feature in *MATPOWER* implemented in  
 510 *MATLAB*. For the 24-hour period simulation, the location set 1 is used to show the  
 511 effectiveness of the control strategy. However, at the end of this section, the results  
 512 from all location sets, while running the simulation for a year, are presented to  
 513 identify the best location for the stations.

514 To achieve the optimisation goal, the algorithm illustrated in Fig. 1 is applied to the  
 515 system for a 24-hour period with a time resolution of one hour to match the available  
 516 wind speed data. The other loads in the systems were assumed to be constant  
 517 during each simulation time interval. The UK electricity demand profile on the 6<sup>th</sup> of  
 518 January 2014 is scaled down to *UKGDS* demand scale and used for this simulation.

519 Fig. 5 shows the demand from the three filling stations within the network during the  
 520 simulation. The result show that the demand of station 1, which is located at bus 53  
 521 (in location set 1), is much lower than the demand of other stations. This means that

522 just two filling stations were able to deal with most of the problems created as the  
523 result of adding intermittent renewable power from wind farms, and there was no  
524 need to increase the demand of the first station to any significant level to improve the  
525 performance of the grid. Therefore, station 1 will have the lowest hydrogen  
526 production, and according to the algorithm in Fig. 3 it is more likely to go into standby  
527 condition during the simulation if there is lack of wind power generation.

528 Fig. 6 shows the aggregate surplus wind power on feeder 8 and the aggregate  
529 demand from all stations. As specified in the control strategy, the aggregate demand  
530 of electrolyzers is always below or equal to the surplus wind power within the system  
531 if this surplus power is a positive value. The difference of power between two curves  
532 in Fig. 6 is the power that is exported to other feeders of the power system. In cases  
533 where the aggregate surplus power becomes negative or zero, the demand of the  
534 filling stations will be zero to avoid the electrolyzers working with non-renewable  
535 power. In such cases, some limited power will also be imported from the substation  
536 to supply some of the local non-electrolysis demands, which were not fully supplied  
537 due to lack of local wind power generation.

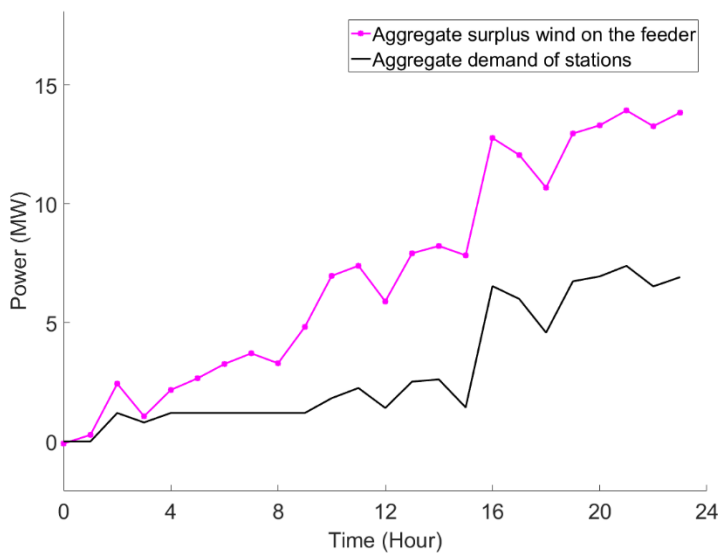


538

539

*Fig. 5 Demand of stations within the network during a 24-hour simulation*

540



541

542

*Fig. 6 Aggregate surplus wind power and aggregate demand of hydrogen stations*

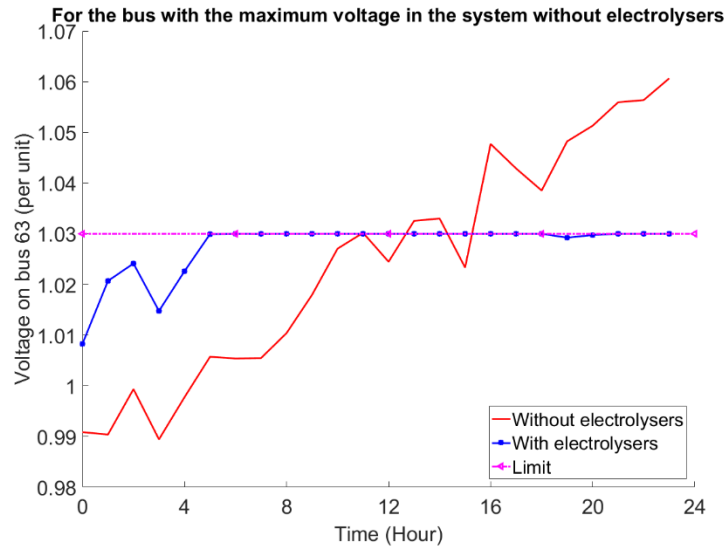
543



544 The total amount of wind energy absorbed by the network during the one day was  
545 equal to 300.6 MWh, and about 69.4 MWh of energy was used by electrolyzers in  
546 the filling stations. The rest of the wind energy was consumed by the local demand  
547 on the same feeder or the demand on other feeders.

548 With the introduction of the electrolyzers to the system, the voltages on different  
549 system nodes change. For example, the voltage on bus 63, which has a nominal  
550 voltage of 11KV, is shown in Fig. 7. This bus was selected because it had the  
551 maximum voltage rise due to of adding wind farms without the utilisation of  
552 electrolyzers. As was expected, the maximum voltage rise occurred on one of the  
553 buses where wind farms were added to the system. After utilisation of electrolyzers,  
554 the voltage of the bus remained within the acceptable limits. In addition, the  
555 electrolyzers smooth the voltage fluctuation on this bus in comparison to the first  
556 scenario. The standard deviation of the voltage on this bus without utilisation of  
557 electrolyzers was 0.0229 pu, which reduced to 0.0056 pu after utilisation of  
558 electrolyzers during a 24 hour simulation.

559 The simulation results show that the voltage limit on many buses were breached at  
560 least once during the simulation in the system without electrolyzers, and that all of  
561 them are driven back within the limits as the result of utilisation of the control strategy  
562 with electrolyzers.

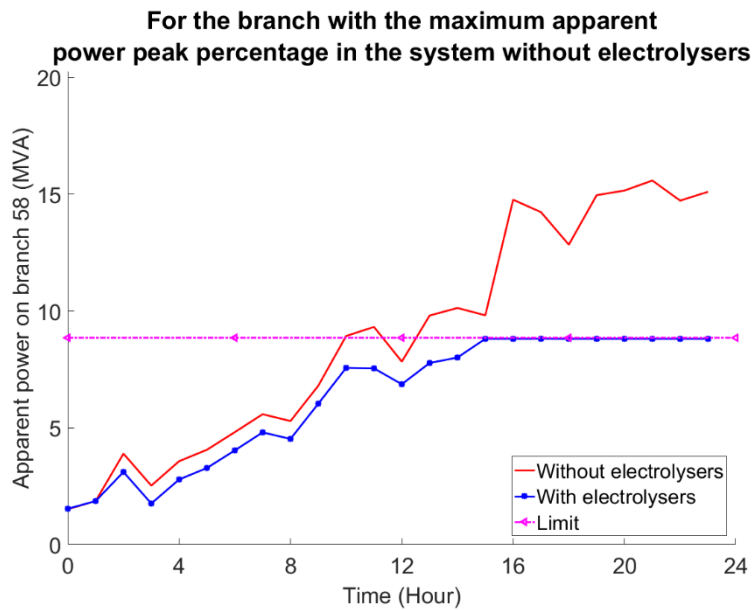


563

564 *Fig. 7 The voltage on bus 63 before and after adding electrolyzers to the system*

565

566 Fig. 8 shows the amount of apparent power on the branch of power system, which  
 567 has the maximum peak value, in percentage terms, without using electrolyzers  
 568 during the simulation. It is obvious that the after using the electrolyzers within the  
 569 system the apparent power of this branch was controlled to remain within the  
 570 acceptable limits. The simulation results show that the apparent power limit on  
 571 branches 53, 54, 55, 56, 57 and 58 were breached at least once during the 24-hour  
 572 simulation in the system without electrolyzers, and all of them were driven back  
 573 within the limits as the result of utilisation of the control strategy with electrolyzers.



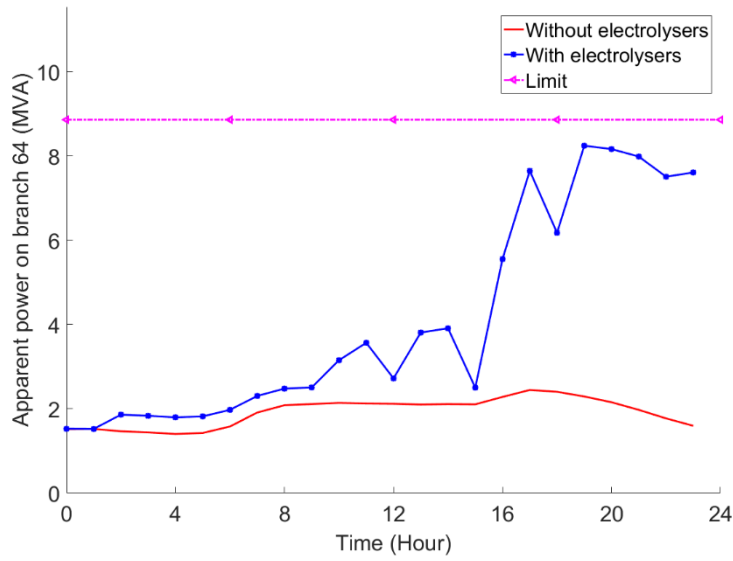
574

575 *Fig. 8 Apparent power on a branch of power system with the biggest peak*  
 576 *percentage during the simulation*

577

578 On the other hand, there were some branches of the power system, which were  
 579 underutilised in the system without electrolyzers, and their apparent power peak was  
 580 only a fraction of the nominal capacity limit of the branch. Fig. 9 shows the apparent  
 581 power of branch 64 of the power system with and without utilisation of electrolyzers.  
 582 It has reached a much higher average apparent power while operating with  
 583 electrolyzers. This shows the effectiveness of the control strategy to increase the  
 584 utilisation of network assets and to remove the need for grid upgrades and  
 585 associated costs while respecting the power system constraints and producing  
 586 'green' hydrogen for the transport sector.

587



588

589 *Fig. 9 The apparent power of branch 64 of the power system with and without*  
 590 *utilisation of electrolyzers*

591

592 To quantify the probability of constraint violations the following attributes, which were  
 593 proposed in [36], are used in this work.

594 The probability of voltage constraint violation ( $VB_{Prob}\%$ ) is calculated as the ratio of  
 595 the total number of time steps that at least one node within the network had a  
 596 voltage constraint violation divided by the total number of simulation time steps.

597 
$$VB_{Prob}\% = \frac{\sum_{k=1}^{NDP} VB_k}{NDP} * 100 \quad (15)$$

598 where

599  $VB_k$  is the function that indicates whether there has been any voltage violation within  
600 the grid at time interval 'k'.

$$601 \quad VB_k = \begin{cases} 0 & \text{if } (|V_i^{Min}| \leq |V_i^k| \leq |V_i^{Max}| \quad \forall i \in B) \\ 1 & \text{otherwise} \end{cases} \quad (16)$$

602 Similarly, the probability of thermal limit violations ( $TLB_{Prob}\%$ ) is calculated as the  
603 ratio of the total number of time steps that at least one branch within the network was  
604 overloaded divided by the total number of simulation time steps.

$$605 \quad TLB_{Prob}\% = \frac{\sum_{k=1}^{NDP} TLB_k}{NDP} * 100 \quad (17)$$

606 Where  $TLB_k$  is the function indicating whether there has been any thermal limit  
607 violation within the grid at time interval 'k'.

$$608 \quad TLB_k = \begin{cases} 0 & \text{if } (|I_{ij}^k| \leq |I_{ij}^{Lim}| \quad \forall i, j \in B) \\ 1 & \text{otherwise} \end{cases} \quad (18)$$

609 These attributes measure the probability of any bus or branch in the system being  
610 out of acceptable limits. The probability of a particular bus or branch being out of  
611 bounds is equal to or lower than the probability of the system being out of bounds, so  
612 such attributes provide a measure of the worst case performance of the system as a  
613 whole [36].

614 The one-day simulation results show that the voltage violation and overload  
615 probability were 70.83% and 50%, respectively, before adding electrolyzers to the

616 power system. However, after utilisation of electrolyzers, those values were found to  
617 be zero due to successful enforcement of the constraint limits by the system central  
618 controller.

619 Total energy loss (MWh) during the simulation on the distribution network is  
620 calculated using the following equation:

$$621 \quad E_{Loss} = T * \sum_{k=1}^{NDP} \sum_{i=1}^{NB} P_{Loss_i}^k \quad (19)$$

622 The amount of reduction in the total energy loss on the distribution network during  
623 the simulation ( $\Delta E_{Loss}$ ) in MWh can be calculated from the following equation:

$$624 \quad \Delta E_{Loss} = E_{Loss}^{Without} - E_{Loss}^{With} \quad (20)$$

625 The percentage reduction in the total energy loss on the distribution network during  
626 the simulation ( $\Delta E_{Loss} \%$ ) can be calculated from the following equation:

$$627 \quad \Delta E_{Loss} \% = \frac{\Delta E_{Loss}}{E_{Loss}^{Without}} * 100 \quad (21)$$

628 The energy flow from the network to the electrolyzers caused a reduction of 5.2  
629 MWh in the total energy loss of the distribution network. This is around 41.5% less  
630 than the distribution loss on the system without electrolyzers. Despite the fact that  
631 the electrolyzers act as additional demand on the electrical network, they reduced  
632 the distribution losses significantly in this study. The reduction in distribution losses is  
633 due to the consumption of some of the surplus power generated by wind farms by

634 electrolysers on the local feeder, instead of exporting all of the surplus power to  
635 other feeders.

636 After proving the effectiveness of the control strategy during the one-day simulation  
637 using set 1 for the location of hydrogen stations, the simulation was run for a  
638 duration of one year with time interval of one hour for all of the location sets and the  
639 results are included in Table 3. The demand profile of the UK during 2014 [31] was  
640 scaled down to match the *UKGDS* demand level and was used for this simulation.

641 The total hydrogen produced (*TH2P* in metric tonne (t)) during the simulation at all of  
642 the electrolysis hydrogen filling stations is calculated from the following equation.

$$643 \quad TH2P = \sum_{k=1}^{NDP} \sum_{j=1}^{NS} \sum_{i=1}^{NAEL_j^k} H2P_{ij}^k / 1000 \quad (22)$$

644 The total energy (MWh) delivered to all of the stations is calculated from the  
645 following equation.

$$646 \quad E_{St} = T * \sum_{k=1}^{NDP} \sum_{i=1}^{NS} SD_i^k \quad (23)$$

647 An income function (*Income*) is defined to find the best location set to maximise the  
648 amount of hydrogen production and consequently the profit from selling hydrogen  
649 while minimising the energy cost of stations, aggregate capital costs of stations, and  
650 the total energy loss on the network and during the simulation. The objective is to  
651 maximise this income function.

$$652 \quad \text{Income} = C_3 * TH2P - C_4 * E_{St} - C_5 * NDP * T * \sum_{i=1}^{NS} OSZ_i + C_6 * \Delta E_{Loss} \quad (24)$$

653 Where  $OSZ_i$  is the optimal size of station 'i' in MW, and it is determined by the  
654 maximum demand of each station during a year simulation.

655 The first term in 'Income', which is  $C_3 * TH2P$ , is included to increase the chance of  
656 selecting the best answer with the highest hydrogen production. This also increases  
657 the chance of selecting the answer with a higher utilisation factor for stations, which  
658 will result in more hydrogen production and more profit.  $C_3$  is the selling price of  
659 hydrogen (£8/kg or £8000/t [37]).

660 The second term in 'Income', which is  $C_4 * E_{St}$ , is included to reduce the cost of  
661 electrical energy from the function value, and it is also assumed that  $C_4 = C_2$ . Usually  
662 filling station operators who have electrolyzers to produce hydrogen can accept  
663 electricity from the grid at any time during a day. If an operator agrees to take some  
664 of the surplus electricity produced by a wind generator at any time and accepts the  
665 peaks and troughs of the received power, then the electricity price for that consumer  
666 would fall to a lower price, and it will result in a price reduction of the hydrogen  
667 produced by the electrolyzers. However, such price reduction is not included in the  
668 simulation here.

669 In this work, it is assumed that  $C_5 = C_1$  and  $C_6 = C_2$  as both  $C_1$  and  $C_5$  are the  
670 coefficients to size stations and  $C_2$  and  $C_6$  are the coefficients for the cost of energy  
671 loss on the system.

672 Considering the proximity to a place with high demand for hydrogen could be added  
673 as another optimisation variable, but at this stage, it would need very random



674 assumptions regarding the number of HFCVs visiting the site during the lifetime of  
675 each station. In addition, in an operational hydrogen economy, there would be many  
676 ways of hydrogen production and delivery, which would again change during the  
677 lifetime of each station. It is possible that some of the hydrogen needs of stations  
678 would be supplied via other forms of hydrogen production and delivery. If the  
679 designer of the system becomes able to forecast the above factors with good  
680 accuracy, then they could be added in the optimisation process.

681 Results of Table 3 show that selection of location set 2 will lead to the best result that  
682 has the maximum 'Income' value. Interestingly, the percentage of distribution loss  
683 reduction for all of the location sets are close to 27%.

684 The final size of some of the stations is found to be lower than 2 MW, inferring that  
685 only one electrolyser with a lower nominal demand will be sufficient for those  
686 stations. In such cases, the minimum demand of the station will be lower than the  
687 initial minimum demand assumed in the control strategy. In addition, for the cases  
688 where the final size of a station is not an integer multiple of 2 MW, smaller  
689 electrolysers can be used to fill the fraction, although, in practice, the commercial  
690 availability of electrolysers would be constrained to limited sizes.

691 The results show that after applying the control strategy, the voltage and apparent  
692 power limits were fully within the limits for all of the location sets except set 5. For  
693 this last location set, the voltage violation probability was reduced from 72.9% to 0,  
694 but the overload probability was reduced from 19% to 1.46% and did not reach zero.

695 This means that location set 5 is not suitable for electrolysis stations if the power  
696 system operator wants to operate electrolyzers with the existing network without any  
697 grid upgrade or wind power curtailment. However, the reduction of overload  
698 probability means that, if there is the possibility to curtail wind power, then it will still  
699 less often happen while using the proposed control strategy with location Set 5. The  
700 value of 'Income' was also minimum for this location set, emphasising its lack of  
701 suitability for the system.

702

703 *Table 3 Results of a year simulation for different location sets in case study 1*

Location set	Set 1	Set 2	Set 3	Set 4	Set 5
$TH2P$ (t)	210.3	208.6	207.4	206.5	212.2
$E_{St}$ (MWh)	10,912	10,848	10,789	10,738	11,049
$\Delta E_{Loss}$ (MWh)	765.4	757.2	750	747.6	769.9
$\Delta E_{Loss}\%$	27.3%	27%	26.7%	26.7%	27.5%
$OSZ_1$ (MW)	0.4	0.4	0.4	0.4	6
$OSZ_2$ (MW)	3.5	2.79	2.76	5.9	6
$OSZ_3$ (MW)	6	6.0	6.0	6	6

Income (£k)	299.6	363.6	358.7	28	-535.9
$VB_{Prob}^{With\%}$	0%	0%	0%	0%	0%
$TLB_{Prob}^{With\%}$	0%	0%	0%	0%	1.46%

704

705 Despite having the same initial size, the hydrogen stations at different locations had  
706 different demand set-points selected by the control strategy, and therefore they had  
707 a different final size in the optimised system. It is also not practical to balance the  
708 amount of hydrogen produced in the stations with this control strategy, resulting in  
709 different amounts of hydrogen production at different stations. Due to implementing  
710 the proposed control strategy, a fuel station might have a significantly lower demand  
711 in comparison to other stations due to its location during the simulation, meaning that  
712 its impact on the improvement of power system operation is very small.

713 One of the advantages of the presented control strategy used in this work is that  
714 there is no need to forecast the wind power availability within the system, and it is  
715 assumed that the grid control centre can just use the real-time data from the wind  
716 power generation units and local demand to calculate the set-point for the demand of  
717 each hydrogen station.

718 For the current network used in this work, it takes only 250ms to run the algorithm for  
719 each time interval, while using a PC with an Intel Core i7 processor of 3.4GHz and a  
720 RAM of 16GB. Execution of a full year simulation takes about 40 minutes for each

721 location set within the UKGDS network. However, full year simulation only needs to  
722 be done offline before construction of stations, so it is not necessary to have very  
723 small simulation duration.

724 To investigate the impact of initial power rating of filling stations and size of wind  
725 farms on the results two more case studies are simulated for a duration of a year,  
726 and their results are included in Table 5 and Table 7, respectively.

727 **Case study 2:** The rating of wind farms is unchanged, but the initial size of stations  
728 has increased by 50%. Details of this case study are included in Table 4.

729 **Case study 3:** The rating of wind farms is increased by 50%, and as a result, the  
730 initial size of stations has increased using Eq. (1). Details of this case study are  
731 included in Table 6.

732 As shown in Table 4, the size of wind farms remained unchanged at 10 MW while  
733 the initial size of stations is increased from 6 MW in case study 1 to 10 MW in case  
734 study 2. The voltage break and overload probabilities have remained unchanged in  
735 the system without electrolysers in comparison to case study 1.

736 As shown in Table 5, despite the fact that the maximum final size that the stations  
737 were allowed to reach was 10 MW in this case study, the maximum optimal size  
738 found is only 7.9 MW. This shows that there is no need to increase the initial size of  
739 stations to a very high limit as the optimisation process will try to find the minimum  
740 size able to satisfy optimisation objectives.

741

742

*Table 4 Details of case study 2*

Parameter	Value
$S_W^i$ (MW)	10
$S_{St}$ (MW)	10
$VB_{Prob}^{Without\%}$	72.9%
$TLB_{Prob}^{Without\%}$	19%

743

744 Interestingly, the percentage of distribution loss reduction for all of the location sets  
745 has remained close to 27% without significant change in comparison to the first case  
746 study. In addition, increasing the initial size of stations did not improve the voltage  
747 and thermal limit violation probabilities in location set 5, which had the worst income.  
748 The value of income function for all location sets except set 3 are worse in  
749 comparison to the first case study. However, the value of income function is bigger  
750 for set 3, which is the optimal solution. This means that case study 2 has a slightly  
751 better optimal solution in comparison to the first case study. Therefore, it can be  
752 recommended that the initial size of stations proposed in the beginning of this paper  
753 can be increased by 30% to achieve a better optimal solution. However, if the  
754 optimal location set were not available for construction of filling stations using this  
755 strategy, then the strategy used in the first case study would be preferred to find the

756 best size of stations. In addition, adopting this new sizing approach can lead to  
 757 accepting large gaps between the optimum size of one station and the other ones,  
 758 i.e. in the results from set 3, the optimal size of station 3 is 7.8 MW while the  
 759 optimum sizes of other two stations are only 1.1 and 0.4 MW. This is not preferable  
 760 from practical point of view as it will cause placing one big station and another very  
 761 small station on the network, and therefore they will have big differences in the  
 762 amount of hydrogen they produce.

763

764 *Table 5 Results of case study 2 for a year simulation*

Location set	Set 1	Set 2	Set 3	Set 4	Set 5
$TH2P$ (t)	216.3	214.7	213.5	212.6	221.5
$E_{St}$ (MWh)	10,911	10,845	10,783	10,730	11,190
$\Delta E_{Loss}$ (MWh)	764.7	753.7	744	739.2	781.5
$\Delta E_{Loss}\%$	27.3%	26.9%	26.5%	26.4%	27.9%
$OSZ_1$ (MW)	0.4	0.4	0.4	0.4	6.9
$OSZ_2$ (MW)	3	3	1.1	7	7.8
$OSZ_3$ (MW)	7.9	7.8	7.8	7.7	7

Income (£k)	204.5	200.9	396.4	-220.3	-857.8
$VB_{Prob}^{With}\%$	0%	0%	0%	0%	0%
$TLB_{Prob}^{With}\%$	0%	0%	0%	0%	1.47%

765

766 In case study 3, the size of wind farms has increased to 15 MW and the initial size of  
767 stations has also increased to 10 MW according to Eq. (1). As a result, the voltage  
768 break and overload probabilities in the system without electrolyzers have also  
769 increased to 78.9% and 41.4%, respectively.

770

771

*Table 6 Details of case study 3*

Parameter	Value
$S_W^i$ (MW)	15
$S_{St}$ (MW)	10
$VB_{Prob}^{Without}\%$	78.9%
$TLB_{Prob}^{Without}\%$	41.4%

772

773 As shown in Table 7, the percentage of loss reduction in the system with  
774 electrolyzers has increased significantly to around 54% in case study 3, due to

775 injection of a significant amount of wind power to the system during the simulation. In  
776 addition, the amount of hydrogen production, energy absorbed by stations, and  
777 income have also increased significantly. However, the controller has not been able  
778 to satisfy the overload problem completely and just managed to reduce it to 1%  
779 during the simulation for most of the location sets. The highest amount of income  
780 function in this case study belongs to location set 5. However, the overvoltage and  
781 overload probabilities were rather higher and equal to 2.42% and 16.7%,  
782 respectively, for this location set. Obviously, the system operator cannot add  
783 unlimited capacity of wind farms and electrolyzers to the system expecting that the  
784 controller should achieve the power system constraint limits. If more wind farms were  
785 added to the system, then they would generate more power, and more electrolyzers  
786 could be added to the network to absorb this extra energy. However, the power  
787 system operator should make sure that the network limits would not be violated due  
788 to adding extra wind power capacity or electrolysis demand.

789

790 *Table 7 Results of case study 3 for a year simulation*

Location set	Set 1	Set 2	Set 3	Set 4	Set 5
$TH2P$ (t)	601.9	597.4	593.9	589.7	674.7
$E_{St}$ (MWh)	32,143	31,906	31,711	31,450	36,881



$\Delta E_{Loss}$ (MWh)	3145.9	3,078	3,013	2,964	3,210
$\Delta E_{Loss}\%$	55.2%	54%	52.9%	52.1%	56.4%
$OSZ_1$ (MW)	8.4	8.4	8.5	8.6	10.2
$OSZ_2$ (MW)	10	10	10	10	10.5
$OSZ_3$ (MW)	8.2	8.2	8.1	8.6	7.1
Income (£k)	1036.9	1005.1	981.5	898.8	1335.3
$VB_{Prob}^{With}\%$	0%	0%	0%	0%	2.42%
$TLB_{Prob}^{With}\%$	1%	1%	1%	1%	16.7%

791

## 792 5 Conclusions

793 In this work, a novel approach that uses an extended OPF was proposed to size,  
794 place and control pressurised alkaline electrolyzers located at hydrogen filling  
795 stations to increase the amount of wind power generation capacity within an example  
796 radial distribution network while satisfying the power system constraints and  
797 electrolyser characteristics. Simulation results show the effectiveness of the  
798 proposed control strategy to maintain the power system parameters within  
799 acceptable limits, while directing some of the surplus power to the electrolyzers to  
800 produce 'green' hydrogen. The proposed strategy increases the network asset

801 utilisation while deferring the need for network upgrade investment for the integration  
802 of more intermittent wind power.

803 Three cases were investigated in this work. In the first case study, which represented  
804 the main strategy, the initial size of filling stations were selected based on the main  
805 strategy proposed in the work. The simulator was easily able to find the optimal  
806 solution, which resulted in completely satisfying the voltage and thermal limit  
807 constraints during one year simulation.

808 In the second case study, the size of wind farms was unchanged, but the initial size  
809 of fuel stations were increased by 50%. The optimal location set resulted in a slightly  
810 better income of £396.4k instead of £363.6k during the one-year simulation.

811 However, it is found that adopting the new initial sizing approach in the second case  
812 study can lead to large gaps between the optimum sizes of one hydrogen filling  
813 station compared with the other ones.

814 In the third case study, the size of wind farms was increased by 50%, and as a  
815 result, the initial size of fuel stations was increased according to Eq. (1). Due to this  
816 change, as was expected, the amount of hydrogen production and the income also  
817 increased significantly. However, the extended OPF strategy was not able to fully  
818 solve the overload and overvoltage problems during all of the time steps for the  
819 optimal location set. For other non-optimal location sets, which have lower income,  
820 the voltage constraints were satisfied, but the overload probability reduced to 1%.  
821 This proves that, if we combine this control strategy with wind power curtailment

822 schemes, then we would be able to increase the integrated wind power capacity  
823 within the system significantly by only curtailing the wind power during 1% of the  
824 time.

825 It is financially and technically viable to use alkaline electrolyzers to produce clean  
826 fuel for future transportation needs and, at the same time, use them as dynamic load  
827 to improve the performance of power system while absorbing the additional power  
828 generated by variable renewable resources. Such electrolyzers can provide long-  
829 term energy storage and provide load control on a short-term basis.

830

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