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## Using Surplus Nuclear Power for Hydrogen Mobility and Power-to-Gas in France

Scamman, D. and Newborough, M\*.

ITM Power Research Ltd.

\*corresponding author email address: mn@itm-power.com

### Abstract

*Opportunities exist to utilise excess electricity from renewable and nuclear power generation for producing hydrogen. France in particular has a very high penetration of nuclear power plant, some of which is regularly turned down to follow the electricity demand profile. This excess nuclear electricity could be utilised via the electrolysis of water to satisfy the emerging French market for low-carbon hydrogen (principally for mobility applications and the injection of synthetic gas into the natural gas grid). The described analysis examines the use of electrolyzers to progressively ‘valley fill’ nuclear load profiles and so limit the need for turning down nuclear plant in France. If an electrolyser capacity of approximately 20 GW is installed, there is already sufficient excess nuclear electricity available now to meet the predicted hydrogen mobility fuel demand for 2050, plus achieve a 5% concentration (by volume) of hydrogen in the gas grid, plus produce approximately 33 TWh p.a. of synthetic methane (via the methanation of hydrogen with carbon dioxide). The pattern of electrolyser utilisation requires operation mostly at a variable part load condition, necessitating the adoption of flexible, efficient, rapid response electrolyzers. The proposed approach more fully utilises the substantial existing nuclear power assets of France and provides an additional pathway to renewables for reducing the CO<sub>2</sub> emissions of hydrogen production.*

### Highlights

- Electrolyser operating strategies for increased utilisation of nuclear power generation in France
- Using excess energy for power-to-gas and hydrogen mobility applications
- Hydrogen for large scale power management in electricity transmission and distribution networks
- Demand side management with controllable electrolysis
- Decarbonisation of power, gas and transport systems through increased interconnection

### Keywords

Electrolysers, power-to-gas, hydrogen mobility, demand side management, nuclear power utilisation

## 37 1. Introduction

38 Power system decarbonisation strategies usually rely heavily on achieving greater deployments of  
39 wind farms, solar photovoltaic arrays and nuclear power plant. As the penetration levels increase,  
40 periods of excess energy (or over-generation) occur, because of the temporal mismatch between  
41 electricity supply and demand [1] [2]. Maintaining the dynamic stability of the electricity grid is a  
42 fundamental requirement and so electricity surpluses need to be exported immediately, absorbed or  
43 curtailed as they occur. Curtailment is more widely practised in grids which have limited or no  
44 interconnections to other grids, but in general it is caused by congestion constraints or dynamic  
45 stability concerns [3]. A recent study commissioned by the Fuel Cell and Hydrogen Joint Undertaking  
46 indicated that excess renewable electricity in Germany could amount to nearly 30% of the total  
47 electricity demand by 2050 [4]. This characteristic of increasing amounts of excess energy per MW of  
48 installed capacity weakens the case for achieving high penetrations of renewables or nuclear power  
49 plant, unless electricity can be readily exported to a neighbouring grid or demand can simply be  
50 increased when required [1] [2]. Exporting power as a means of increasing renewable or nuclear  
51 power penetrations has been achieved in some regions (e.g. by Denmark, Germany and France) but,  
52 as the magnitude and frequency of excess energy events increase, simply exporting surpluses to  
53 neighbouring countries as they occur becomes less viable and more curtailment or absorption  
54 (storage) is required.

55  
56 By convention ‘energy storage’ has been assumed to comprise power-to-power storage (P2P)  
57 technologies (such as pumped hydro, batteries and flow batteries), where electricity is absorbed at  
58 one time and discharged as electricity at a later time. Energy storage technologies can thereby provide  
59 power networks with ‘peak shaving’, ‘valley filling’ and renewable power management facilities [5].  
60 However, their economic justification depends largely on the prevailing buy and sell prices for  
61 electricity in a given region. Unfortunately because P2P storage acts to clip peaks as well as fill valleys  
62 in the electrical load profile, its deployment affects adversely the buy/sell price ratio and so, in time,  
63 the economic case for its utilisation is compromised - the law of diminishing returns applies [4].

64  
65 In this context, it is desirable to widen the scope of the decarbonisation objective to include the  
66 absorption of excess energy from the power system for use in the transport and gas systems. The  
67 fundamental energy conversion process that is required to achieve this is the electrolysis of water to  
68 produce hydrogen. By this means excess generation can be exported by:

- 69
- 70 • injecting hydrogen (or synthetic methane derived from hydrogen and carbon dioxide) into the  
71 gas grid – usually referred to as ‘power-to-gas’
  - 72
  - 73 • storing hydrogen in electrolyser-based Hydrogen Refuelling Stations (for refuelling fuel cell  
74 vehicles)
  - 75
  - 76 • storing hydrogen for example in salt caverns for power/heat generation.
  - 77

78 Thereby installed capacities of renewables and nuclear power can continue to grow without  
79 necessarily causing curtailment to increase, because demand is not constrained by the transient  
80 demand profile for electricity. By effectively utilising hydrogen to interconnect the power, gas and  
81 transport systems, a substantial over-generation of power in the power system can be accommodated  
82 and usefully employed [6] [7] [8] [9] [10]. Furthermore, in solar-dominated regions the steep ramp in  
83 the power requirement from thermal power plant during late afternoon can to some extent be  
84 ameliorated [11].

85  
86 This approach may be applied in many countries as a function of the availability, form and capacity of  
87 the gas grid, salt caverns and hydrogen mobility (H2M) infrastructure. In islands with relatively weak

88 electricity grids, or regions with limited interconnections to neighbouring grids (e.g. the UK), the need  
89 to implement an indigenous solution must be faced at relatively low renewable power penetrations  
90 [12]. Conversely strong continental electricity grids can often transmit excess electricity to another  
91 region of lower renewable power penetration; for example, this currently occurs in Southern Germany  
92 due to the high solar PV penetration (Figure 1) [13]. However, for all regions, as the renewable or  
93 nuclear power penetration grows, it becomes increasingly desirable to utilise the excess electricity  
94 locally if curtailment is to be minimised.

95  
96 France has a remarkably low carbon intensity for electricity generation of 61 gCO<sub>2</sub>/kWh<sub>e</sub> due to its  
97 large nuclear power capacity [14], but it remains heavily dependent on imported fossil fuels for  
98 providing heat and mobility. In 2013 transport fuel, natural gas and electricity requirements were  
99 similar, amounting to 494, 470 and 498 TWh respectively [15] [16] [17]. However, their demand  
100 characteristics vary significantly, with the gas demand profile exhibiting the greatest variation across  
101 the year (Figure 2). Outline consideration of Figure 2 suggests that the French transport and gas  
102 systems should be able to readily accommodate any surpluses emerging from the valleys of the  
103 national electrical load profile.

104  
105 In 2013, nuclear power stations in France delivered 402.1 TWh (*i.e.* 80.7% of total electricity  
106 generation) [15], with a net total of 51.7 TWh of electricity exported to neighbouring countries, making  
107 France the biggest exporter of electricity in Europe [18]. The installed nuclear capacity is presently  
108 63.2 GW and the annual load factor is therefore about 73%. In addition, France has about 40 GW of  
109 renewables (including 25.4 GW of hydro, 8.3 GW of wind and 4.7 GW of solar in 2013) [19] [20] [21]  
110 [22] [23]. In 2015 the French Parliament adopted an energy transition bill (2015-922) which will  
111 initiate a number of significant changes to France's energy landscape [24]. The bill's objectives include  
112 a 40% reduction in greenhouse gas emissions by 2030 compared with 1990 levels, with a 75%  
113 reduction by 2050. Fossil fuel consumption will be reduced by 30% compared with 2012 levels by  
114 2030, with the share of renewables in final energy consumption increasing to 32% (40% of electricity  
115 production). Nuclear capacity will be capped at the present level of 63.2 GW, with the share of nuclear  
116 energy in electricity production falling to 50% by 2025. This transition away from fossil fuels towards  
117 a power system based almost entirely around nuclear and renewables by 2050 implies that France will  
118 experience very large amounts of excess renewable electricity and/or excess nuclear electricity.

119  
120 When compared with other nations employing nuclear power, France is unusual in that it applies a  
121 number of methods to control core reactivity in nuclear power plant, so that the total nuclear power  
122 generation profile can better follow the daily electricity demand profile as it unfolds [25] [26].  
123 However, turning nuclear reactors down on a frequent basis decreases the return on capital  
124 investment [27], it reduces the sales income that would otherwise have been achieved had a greater  
125 electricity demand existed at these times [26], it incurs plant costs, and it increases waste as boric acid  
126 is used to reduce the rate of reaction which increases the volume of effluents generated [28]. Instead  
127 if nuclear electricity could be utilised effectively during these periods, the annual load factor could be  
128 increased (within the limits driven by plant maintenance) and nuclear power could make a greater  
129 contribution to decarbonising the French energy system without needing to increase installed  
130 capacity. These periods of turn down, which occur at different times of day/year, represent surpluses  
131 of nuclear power. The associated amounts of electrical energy are referred to here for convenience as  
132 'excess nuclear'; this is analogous to 'excess renewables' when renewable power sources need to be  
133 turned down/off at times of low demand and high availability. Electrolyser operation to utilise excess  
134 energy in a generic power system containing various proportions of renewable and base load zero-  
135 carbon (nuclear) power plant have been investigated previously [1].

136  
137 To help frame the opportunity for excess energy to be employed to enable hydrogen mobility and  
138 power-to-gas (P2G) in France, this investigation considered recent nuclear generation profiles. It made

139 no attempt to predict future nuclear load profiles or to estimate future levels of excess nuclear  
140 electricity, which will be influenced both by the installed capacities of renewables and future  
141 electricity demand profiles.

142  
143 By definition if something is otherwise unsaleable it is of low or zero value. Therefore the absorption  
144 of otherwise unsaleable excess nuclear electricity by electrolysis means this electricity should be  
145 available to electrolyser operators at a low unit price [29] [30]. Rapid response electrolysers may also  
146 sell balancing services to the electricity grid operator to enable the electrolysis load to be switched on  
147 or increased when required [31], rather than requiring the nuclear plant to be turned down. In the  
148 envisaged approach, electrolyser operation would be controlled to utilise only excess nuclear  
149 electricity so that the average load factor of nuclear plant would increase. The electrolysis load would  
150 thereby augment consumer demand for electricity and play an increasingly central role in electricity  
151 supply-and-demand management [32].

152  
153 The main objectives of this study were to identify the required electrolyser operating profiles if excess  
154 nuclear is utilised and to estimate the magnitudes of the contributions that this energy could make  
155 towards meeting hydrogen mobility and power-to-gas requirements in France. With respect to P2G,  
156 both hydrogen injection (H2I) and methanation (SNG production using hydrogen and waste carbon  
157 dioxide) were considered.

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## 160 **2. Nuclear Generation Profiles**

161 The annual variation in nuclear power generation in France for 2011-13 is shown in Figure 3. A  
162 relatively high reliance on electric heating results in a peak in nuclear power output during the colder  
163 winter months of around 60 GW (close to the total nuclear capacity), while output drops to around 40  
164 GW during the summer. Nuclear generation averaged 408.4 TWh p.a. over the period 2011-13, which  
165 is 73.8% of the 553.5 TWh p.a. that could have been generated in an idealised scenario where the  
166 entire nuclear fleet operates continuously. This hypothetical scenario means that up to about 145  
167 TWh p.a. of nuclear generation is being curtailed. Of course the availability of a nuclear power plant  
168 is significantly less than 100%, because it must undergo regular maintenance, so this hypothetical  
169 potential cannot be realised. In practice the unit capability factors (UCF) for nuclear power plant in  
170 France in 2014 ranged from 50.3% to 99.7% [33]. Of the 57 operating plant, 47 were characterised by  
171 an average UCF of 85% while 31 stations achieved an average UCF of 91% - the latter indicates that  
172 load factors well in excess of the national average are achievable.

173  
174 In this investigation it was assumed that the additional opportunity to produce hydrogen with excess  
175 nuclear would motivate the power industry to ultimately achieve an average UCF of 91%. Achieving  
176 this very ambitious target would correspond to providing 100 TWh p.a. of excess nuclear for hydrogen  
177 production. Previous investigations have identified much smaller surpluses of 19.2 and 22 TWh  
178 occurring in 2004 and 2007 respectively, but these represent the difference between actual  
179 production and consumption, not potential production at maximum capability and consumption [29]  
180 [30]. It may take some years to achieve the 100TWh target, but we cite this to provide an indication  
181 of the amount of electricity that is potentially available for electrolysis without requiring the existing  
182 nuclear capacity to be expanded.

183  
184 Weekly average nuclear power generation profiles for winter (Nov-Mar) and summer (Apr-Oct) for  
185 2011-13 show regular patterns in the requirement placed on nuclear power plant across the day/week  
186 (Figure 4). Typically there are two daily valleys; a dip of about 0.5 GW in early afternoon, and a deeper  
187 valley of 1-2 GW overnight. In addition there is a deep weekend valley (including three nights, Friday  
188 to Sunday) of as much as 7 GW below the weekday peak. Weekend and night-time valleys are deeper  
189 in summer than in winter (7 GW versus 3 GW and 2 GW versus 1 GW respectively). These variations

190 in the average load profiles are driven mainly by varying consumer/industrial behaviour patterns  
191 across the week and by weather variations across the year (e.g. different demand levels for electric  
192 heating, air conditioning and lighting).

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### 195 **3. Hydrogen Demand Predictions.**

196

197 Recent studies have estimated the potential for utilising hydrogen in the following three markets in  
198 France: mobility, power-to-gas and power generation: [4] [34] [35] [36] [37].

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200

#### 201 **3.1 Mobility**

202

203 Fuel Cell Electric Vehicles (FCEV) are one of the main options for zero-carbon transport as they provide  
204 longer ranges and much shorter refuelling times than battery electric vehicles (BEV). Germany, the  
205 UK, California, Korea and Japan are building initial hydrogen refuelling station (HRS) networks to  
206 support the early adoption of FCEVs in the 2015-2020 timeframe, rising to much larger numbers by  
207 2030. Toyota, Hyundai, Honda, Nissan and Daimler have each announced plans to start selling FCEVs  
208 in significant quantities, with Hyundai commencing sales in 2014.

209

210 A recent analysis for France called for 73% of the hydrogen consumed by FCEV in 2030 to be produced  
211 via on-site electrolysis in order to achieve a CO<sub>2</sub> saving of 77% relative to new diesel cars in 2030 [34].  
212 It recommended that France itself construct an initial network of 55 hydrogen refuelling stations by  
213 2020, rising to 600 by 2030. This could support 773,000 FCEVs by 2030, requiring 61.4 kt p.a. of  
214 hydrogen from electrolysis (~3.25 TWh<sub>e</sub> p.a.) and a further 28.6 kt p.a. from reformed natural gas and  
215 chlor-alkali plant. By 2050, electrolytic hydrogen production for FCEV refuelling could rise considerably  
216 to 598 kt (requiring ~33 TWh<sub>e</sub> per annum) for refuelling 7.3 million FCEVs.

217

218 Hence it is clear from this preliminary analysis that the current magnitude of excess nuclear available  
219 in France far exceeds the predicted electricity requirement for meeting the 2050 hydrogen mobility  
220 demand. Importantly in the period to 2030 the availability of only modest amounts of excess nuclear  
221 (a few TWh p.a.) would be sufficient to provide a considerable boost to establishing the necessary  
222 hydrogen refuelling infrastructure in France, and thereby assist fuel switching from diesel/gasoline  
223 vehicles to FCEV.

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#### 226 **3.2 Power-to-Gas**

227

228 France currently consumes about 470 TWh p.a. of natural gas, primarily for heating. Decarbonising  
229 the heat network remains a considerable challenge, and power-to-gas (P2G) offers a means for  
230 switching from imported natural gas to indigenously generated synthetic gas. Electrolytic hydrogen  
231 can be mixed with natural gas and injected into existing natural gas networks at low concentrations  
232 and then combusted safely with existing burners and appliances [38]. A clear advantage of this  
233 approach is that the infrastructure is already in place to convey and store large quantities of hydrogen  
234 without the need for additional plant [39]. As most gas networks have not been designed to contain  
235 significant quantities of hydrogen there is normally an upper limit to which hydrogen can be injected;  
236 for France the current limit is 6% by volume, while in Germany and Holland it is 10% and 12%  
237 respectively [40] [41].

238

239 A large EU-funded project has indicated that properly-adjusted gas-fired appliances can  
240 accommodate volume concentrations of up to 20% hydrogen (given favourable natural gas quality),

241 and pipelines could transport gas mixtures containing up to 50% hydrogen (depending on the pipeline  
242 steel used) [38]. Because gas consumption can vary by approximately one order of magnitude with  
243 time of day, some hydrogen buffer storage may be needed within the P2G plant depending on when  
244 the hydrogen is generated to ensure the concentration never exceeds 6%. However, it will not be  
245 feasible to achieve an average concentration of 6% at all times, because this would require an  
246 excessive amount of hydrogen storage. Therefore it was considered that average concentrations of  
247 <6% should be studied.

248

249 Electrolytic hydrogen and carbon dioxide may also be used to generate synthetic methane (SNG), and  
250 its injection to the natural gas grid is not restricted by permissible concentration limits. One recent  
251 analysis [35] reported that hydrogen injection in the French gas grid could capture 25 TWh of excess  
252 electricity per year. It predicted this growing to 75 TWh p.a. by 2050, which would require a  
253 combination of SNG-injection and hydrogen-injection. For SNG, it advocated the upgrading of biogas  
254 as the most cost effective route for sourcing the required CO<sub>2</sub>. A further study [36] identified up to 13  
255 TWh p.a. of excess electricity being available in France by 2030, and up to 67 TWh p.a. by 2050, which  
256 must be transferred out of the power system or lost (as opposed to absorbed by P2P storage  
257 technologies). The estimated requirement for P2G plant in France by 2030 was 1.2-1.4 GW, and up to  
258 24 GW by 2050 [36]. The study called for 5-10% of the installed P2G capacity to be for H2I and the rest  
259 for SNG injection, with the CO<sub>2</sub> requirement supplied entirely from bio-renewable sources.  
260 Furthermore a multiple node model for power flows in NW European countries, has predicted 2030  
261 curtailment levels of 5-10 TWh p.a. in each of France, Germany, Holland, Ireland and Denmark [37]. In  
262 general, the studies undertaken to date provide first order estimates of excess energy levels and they  
263 exclude excess nuclear - more detailed and independent predictions for future magnitudes and  
264 durations of excess renewables and excess nuclear are desirable.

265 The amounts of excess energy occurring in France depend on the assumed penetration levels of  
266 renewable and nuclear plant, but each of the above estimates is less than the current magnitude of  
267 excess nuclear. From the gas grid perspective, the existing 6% by volume limit for hydrogen means  
268 that up to about 9 TWh p.a. of hydrogen could be accommodated if appropriately administered, which  
269 would require ~13 TWh<sub>e</sub> p.a. of excess electricity (assuming an average electrolyser efficiency of 70%).  
270 However, if excess energy is converted to SNG via the methanation of CO<sub>2</sub> and hydrogen, then the gas  
271 grid could absorb very large amounts (e.g. potentially up to the current natural gas consumption level  
272 of ~470TWh p.a.). These outline considerations frame the P2G opportunity and indicate that this  
273 already available sink for excess electricity could enable France to adopt a high nuclear and high  
274 renewables decarbonisation strategy, where the respective installed capacities far exceed the national  
275 peak power demand.

276

### 277 **3.3 Storage with Reconversion to Electricity**

278 France has been identified as a European nation where the storage of large amounts of hydrogen in  
279 underground caverns is geologically feasible [42]. One option is to store the hydrogen generated from  
280 excess nuclear in large, geologic hydrogen stores such as salt caverns, aquifers and depleted gas fields.  
281 France has a number of salt deposits it can use, mainly near its southern and eastern borders [43].  
282 Aquifers are an additional option for more central regions, with existing aquifers in use for natural gas  
283 storage [44]. This hydrogen could provide a seasonal buffer and be utilised by hydrogen gas turbines  
284 for generating power at key times (e.g. during periods of low renewables availability when some fossil  
285 fuelled power plant may otherwise be needed) [4]. This option could therefore facilitate achieving an  
286 extremely low carbon footprint for French grid electricity by 2050.

287

288

## 4. Analysis and Results

The utilisation of excess nuclear was investigated with respect to prospective P2G and H2M objectives across the period to 2050. A time series model, based on a recent hourly dataset for nuclear power generation [15], was developed to analyse the effect of using electrolyzers to ‘valley fill’ the nuclear load profiles. The analysis was undertaken with respect to average weekly and average yearly nuclear load profiles (based on datasets for 2011, 2012 and 2013). A load-dependent assumption was made for electrolyser system efficiency of 60 kWh/kg (66% HHV) at full-load, rising linearly to 55kWh/kg (72% HHV) at 20% load. This was applied irrespective of the different pressure and purity requirements of the hydrogen applications.

It is tentatively estimated that an average 5% hydrogen concentration could be reached by 2030, which would require 223 kt H<sub>2</sub> p.a. (or an electricity input of about 12.3 TWh<sub>e</sub>). Similarly if as predicted the mobility demand reaches 598 kt H<sub>2</sub> p.a. by 2050 [34], the combined H2I and H2M electricity requirements for electrolysis would then be ~45 TWh<sub>e</sub> p.a. This suggests that a 2050 strategy to meet all of the H2M demand plus a 5% hydrogen concentration in the gas grid would account for less than half of the currently available excess nuclear electricity. Therefore SNG production could be employed from the outset, in addition to H2I and H2M.

Clearly how these three respective markets develop is a function of the economic framework in which the electrolyser plant operates. Economic analyses were beyond the scope of the current investigation, but energy conversion processes that use electricity as the input energy are heavily influenced by electricity costs; operational costs rather than capital costs can have a major influence on the unit cost of electrolytic hydrogen. Of particular importance are the financial values ascribed to the excess electricity that cannot be sold at the time of generation and to the balancing services payments made to electrolyser operators for absorbing this electricity upon instruction. (For example one recent study indicated that the use of excess renewables to power 8GW of power-to-gas methanation systems injecting SNG into the UK gas grid with reconversion to power via combined cycle gas turbines would be more cost effectively than building Hinkley C nuclear power station [45]).

The primary influencing variables to be considered in a further study include: the tariff paid for absorbing excess nuclear electricity; the balancing services income earned from the grid operator to increase or reduce load when required; the average conversion efficiency; the average utilisation factor across life; plant lifetime for the required utilisation profile; maintenance costs; and any incentives applied by supportive policies (such as hydrogen/SNG feed-in tariffs, or low rates of tax on hydrogen fuel).

### 4.1 Valley-Filling of Average Weekly Profiles

The valleys in the average weekly load profile for 2013 (Figure 5) were progressively filled to achieve smoother load profiles of greater load factor and annual hydrogen yields were simply extrapolated from the results. Initially electrolysis was applied to fill the afternoon valleys, then increasing capacities were assumed for filling deeper valleys in this load profile (Figures 6-9).

Unlike analyses based on utilising excess renewable energy, there is clearly a regular availability of valleys to fill in the nuclear load profile which justifies undertaking an analysis based on the average week. In practice, the actual electrolyser utilisation levels per week for a given installed capacity will vary across the year, depending on how the weekly load profile varies from the average. For example greater electrolyser utilisation factors would be achievable in summer.

340 As expected, the proposed approach results in a low electrolyser utilisation (Table 1). This is  
 341 influenced by periods of dormancy and significant amounts of part-load as opposed to full-load  
 342 operation. The part-load operation serves to improve the average conversion efficiency and extend  
 343 electrolyser lifetime, which tends to be determined by run-hours (or more precisely, throughput)  
 344 rather than a fixed number of years.  
 345

Installed Electrolysis Capacity (GW)	Electrolyser Energy Utilisation (%)	Electrolyser Run Time (h p.a.)	Degree of 'Valley Filling'	Hydrogen Production (kilo-tonnes H <sub>2</sub> p.a.)
0.5	20	3,180	Afternoon and some overnight smoothing of nuclear load profile	16
2.0	21	5,944	Overnight smoothing of nuclear load profile	67
3.5	31	8,551	Steady nuclear load profile on weekdays	170
6.0	26	8,701	Steady nuclear load profile all week	247

346 **Table 1: Performance Summary for Various Installed Electrolyser Capacities for the Average**  
 347 **Weekly Nuclear Load Profile**

348 As expected an installed capacity of 0.5 GW of electrolysis is sufficient to fill the afternoon valley and  
 349 make a small contribution to filling the overnight valley (Figure 6). Electrolyser operation is  
 350 characterised by a demanding utilisation profile across the week, with a high number of start-ups and  
 351 large swings from 0 to 100% and back again. The electrolysers will start up twice daily, operate mainly  
 352 at part load at a low average utilisation of 20%, and make only a modest contribution towards meeting  
 353 future hydrogen demands (16 kt p.a.). Note these values may be slight overestimates as they are  
 354 based on averaged data (e.g. 0.5 GW will not be sufficient to fill the afternoon valleys on some days  
 355 when the valley depth reaches 1 GW). Counteracting this, however, is the ability of an electrolyser to  
 356 accept loads significantly greater than its nominal capacity for brief periods; when applied to real-time  
 357 data this overloading capability can allow utilisation and production levels to exceed (if desired) those  
 358 reported in Table 1.  
 359

360 Increasing the installed capacity of electrolysis to 2.0 GW would be sufficient to smooth substantially  
 361 the nuclear load profile on weekdays (Figure 7) and will enable a step in hydrogen production from 16  
 362 to 67 kt p.a., which is roughly equivalent to the 2030 H2M demand. As the installed capacity is  
 363 increased further to 3.5GW, the hydrogen yield becomes more significant and the annual run time  
 364 increases substantially (Table 1). The required electrolyser technology will therefore need to be 'on'  
 365 for much of the year (reducing the number of start-ups) but operate mainly at part-load (Figures 8 and  
 366 9). However, it will be challenging economically to progress from an installed capacity of 3.5GW  
 367 operating at a utilisation factor of 31% to one of 6.0 GW operating at 26% utilisation. This suggests  
 368 that supportive government policies will be required if the considered approach is to progressively  
 369 step up its annual hydrogen yield.  
 370

371 To achieve a flat load profile across an average week, about 6 GW of electrolysis would be required  
 372 (Figure 9). This would yield almost sufficient hydrogen annually to meet both the 2030 H2M demand  
 373 and a 5% hydrogen concentration in the gas grid (Table 1). It would appear therefore that the  
 374 operation of up to 6 GW of electrolysis in France by 2030 in the described manner would be a good  
 375 strategy for meeting the predicted 2030 H2M and H2I requirements *and* valley fill the average weekly  
 376 nuclear generation profile. This could be achieved by deploying several hundred electrolyser-HRS and  
 377 P2G systems.



378

379 However, 6 GW of electrolysis with an average utilisation of 26% will only capture about 13.5 TWh of  
380 the available excess nuclear. A more ambitious strategy based on valley-filling the annual profile is  
381 needed if greater use of excess nuclear is to be achieved.

382

383

#### 384 **4.2 Valley-Filling of Annual Profiles**

385 The 'valley' in the annual load profile is much deeper and wider than those occurring in the average  
386 weekly profiles. Figure 3 suggests that an installed capacity of approximately 20 GW would be required  
387 to valley-fill the annual profile. Therefore the model was adjusted to consider greater installed  
388 capacities of electrolysers. It was found that a 20 GW implementation operating at an average  
389 utilisation of 66% could capture about 115 TWh of excess nuclear and generate 2,050 kt p.a. of  
390 hydrogen. This would easily satisfy the 2050 H2M requirement and so may be considered as a major  
391 pathway for satisfying the hydrogen mobility demand. Furthermore, in addition, a 5% hydrogen  
392 concentration in the gas grid could be achieved, while still leaving the majority of the hydrogen  
393 production for generating SNG (Figure 10).

394

395 Approximately 33 TWh p.a. of SNG could be produced in this manner, which is sufficient to reduce  
396 France's current annual natural gas consumption by 6.9%. There is a seasonal trend in SNG production  
397 (Figures 10 and 11), which suggests it could displace up to 40% of the current natural gas use in the  
398 summer months, while making only a very modest contribution in winter. Despite having a large  
399 electrolyser capacity in the power system, the effect of hydrogen and SNG upon the gas system will  
400 be small (Figure 11). Hence P2G approaches utilising excess nuclear may best be considered as  
401 contributors to assisting gas-grid decarbonisation (analogous to bio-methane injection) rather than as  
402 a major solution.

403

404 Figure 12 provides an illustratory roll out scenario for the power-to-gas and hydrogen mobility  
405 applications across the period to 2050. Some combination of hydrogen use for mobility (high value)  
406 and in the gas grid (lower value) is projected, but the relative amounts will of course depend on  
407 economic criteria that define the market framework. Stakeholders and policymakers still need to  
408 agree the remuneration framework for synthetic gas injection and targets for capturing rather than  
409 wasting excess energy. However, it is clear that excess nuclear could serve to meet the entire  
410 hydrogen requirement of the predicted 2050 FCEV market, whilst contributing both a useful hydrogen  
411 concentration plus a substantial input of SNG to the gas grid (Fig. 12).

412

413

## 414 **5. Conclusions**

415

416 Increased utilisation of existing nuclear power plant, rather than turning plant down during low  
417 demand periods, presents a substantial untapped source of low-carbon energy in France. It may be  
418 applied to meeting the future demand for hydrogen mobility and for reducing dependency on  
419 importing fossil fuels via power-to-gas by controlling electrolyser operation to 'valley fill' the nuclear  
420 load profile. The proposed approach warrants a very low unit price for electricity, because it provides  
421 a service that absorbs otherwise unsaleable electricity.

422

423 A progressive deployment of electrolysers that reaches 20 GW by 2050 is identified as being a most  
424 expedient implementation for utilising excess nuclear electricity. A deployment of about 6 GW by 2030  
425 would substantially flatten the average weekly load profile placed on existing nuclear plant, and so  
426 simplify operation and maximise the return on investment. It would provide sufficient fuel to easily  
427 meet the predicted hydrogen mobility requirement and make a significant contribution to the gas

428 sector. Annual hydrogen yields may be augmented further by absorbing excess renewable power  
429 when it occurs out of time phase with excess nuclear.

430

431 The identified electrolyser operating profiles for absorbing excess nuclear electricity exhibit  
432 characteristically low utilisation factors with substantial periods spent at part load. This requires fast-  
433 responding electrolyser technology and should yield greater average conversion efficiencies and  
434 electrolyser life expectancies. Further research should address the techno-economic case for  
435 implementation, with consideration given to input electricity costs, balancing services income, the  
436 effects of low utilisation on system life, load-dependent conversion efficiency, overloading at high  
437 current density for restricted periods to reduce capital costs, the influence of hydrogen feed-in tariffs,  
438 hydrogen taxation levels, the temporal coincidence of excess nuclear and excess renewables and the  
439 opportunity to increase utilisation by absorbing both for the period to 2050.

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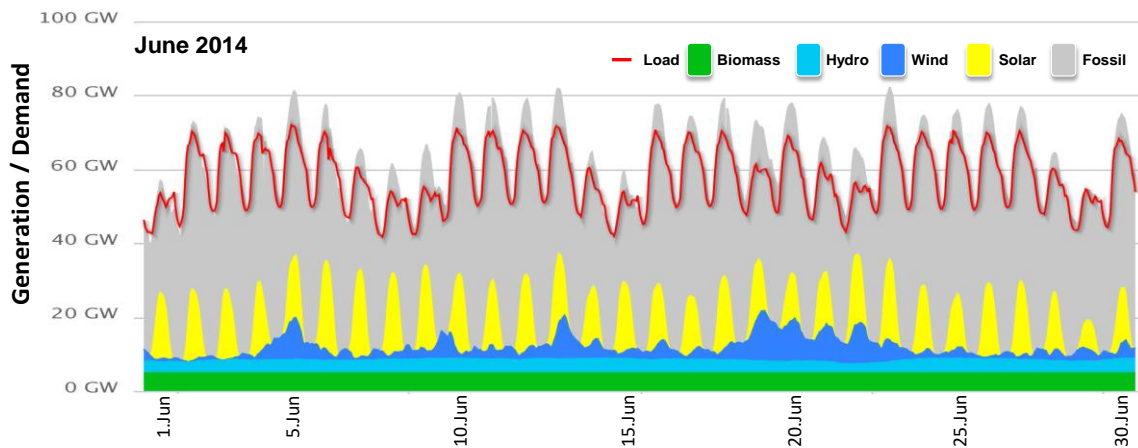
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445 **Figures**



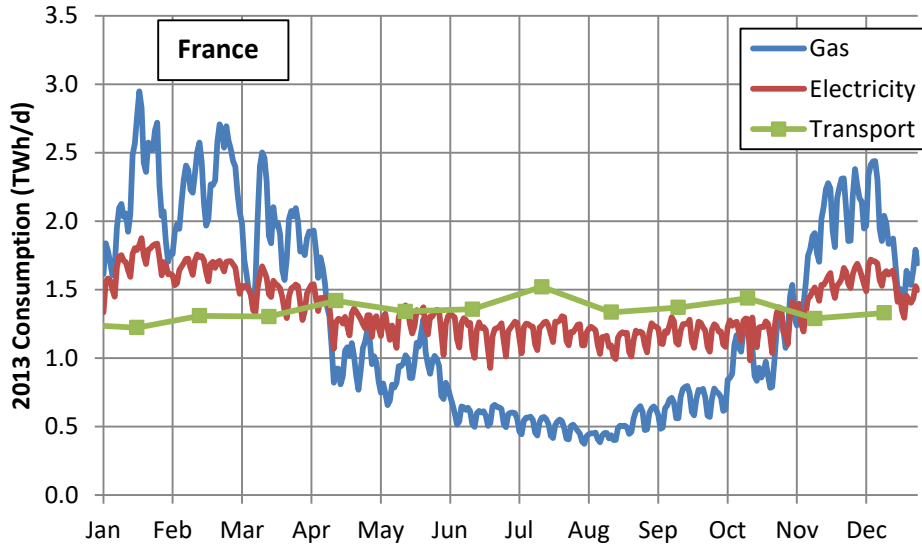
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448 **Figure 1: Solar power in Germany causing excess energy to be exported to neighbouring countries**  
449 **or curtailed [13]**

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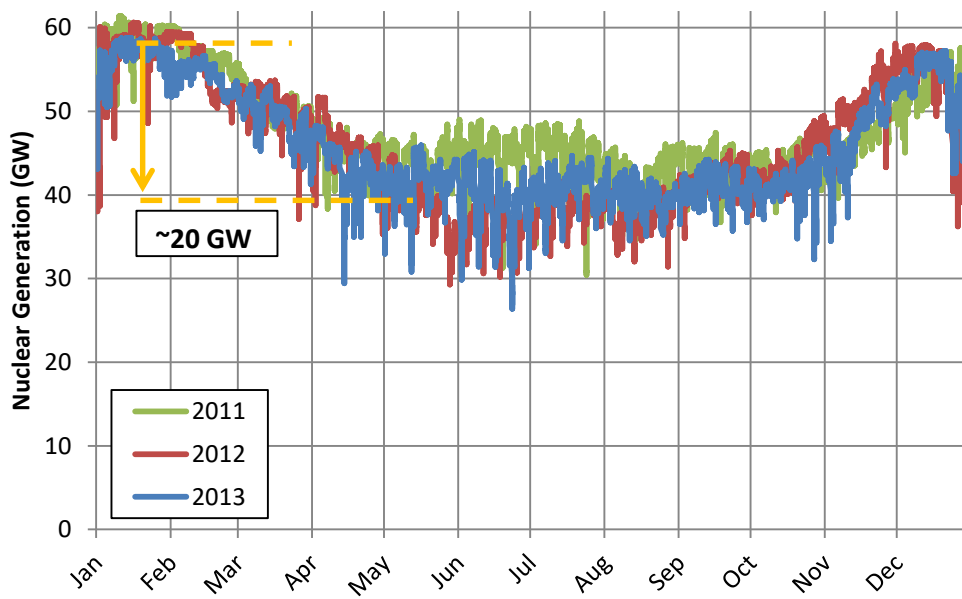
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**Figure 2: Energy consumption in France for Gas, Electricity and Transport Fuel (total diesel and petrol deliveries) [15] [16] [17]**

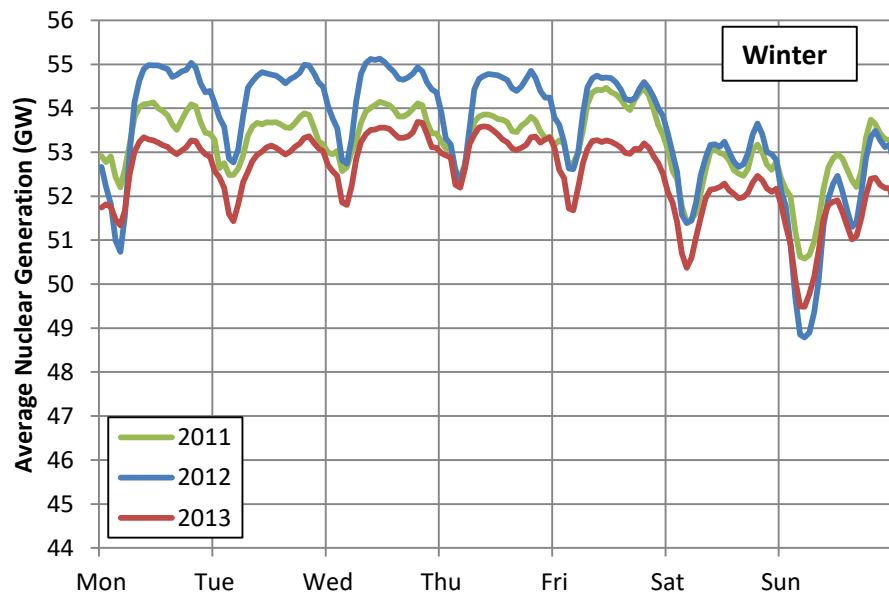
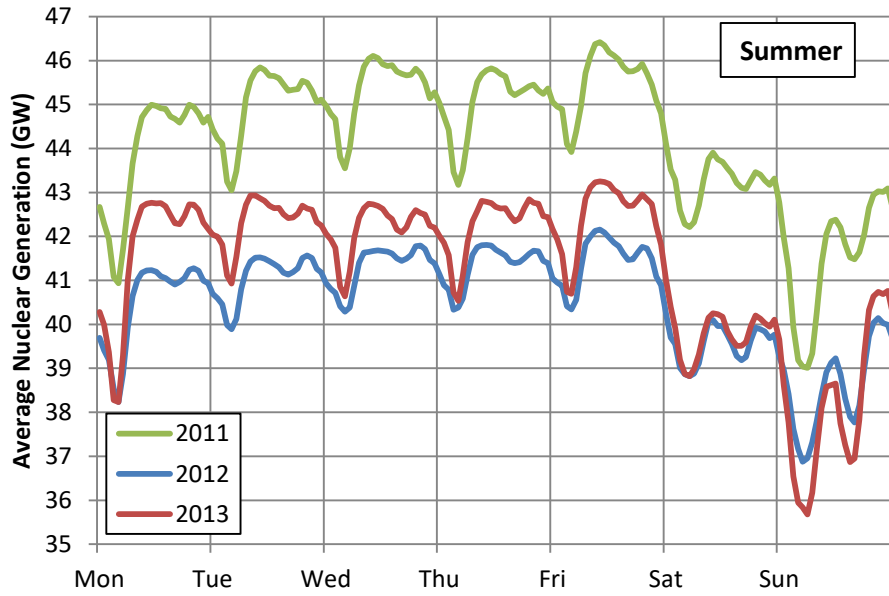
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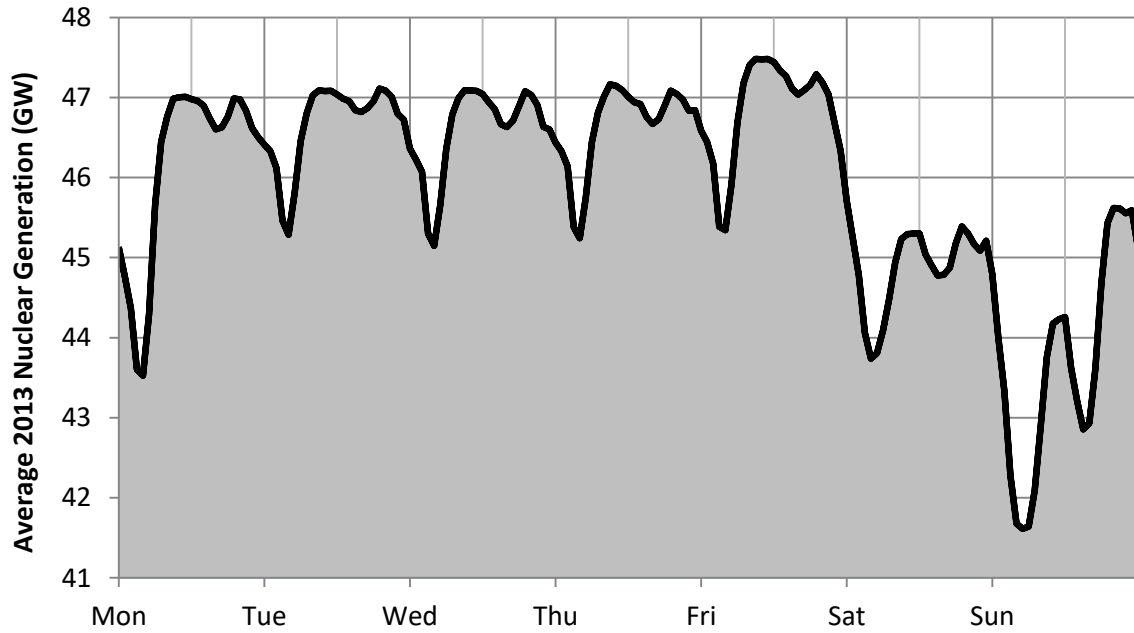
**Figure 3: French nuclear generation variation 2011-13 [15]**



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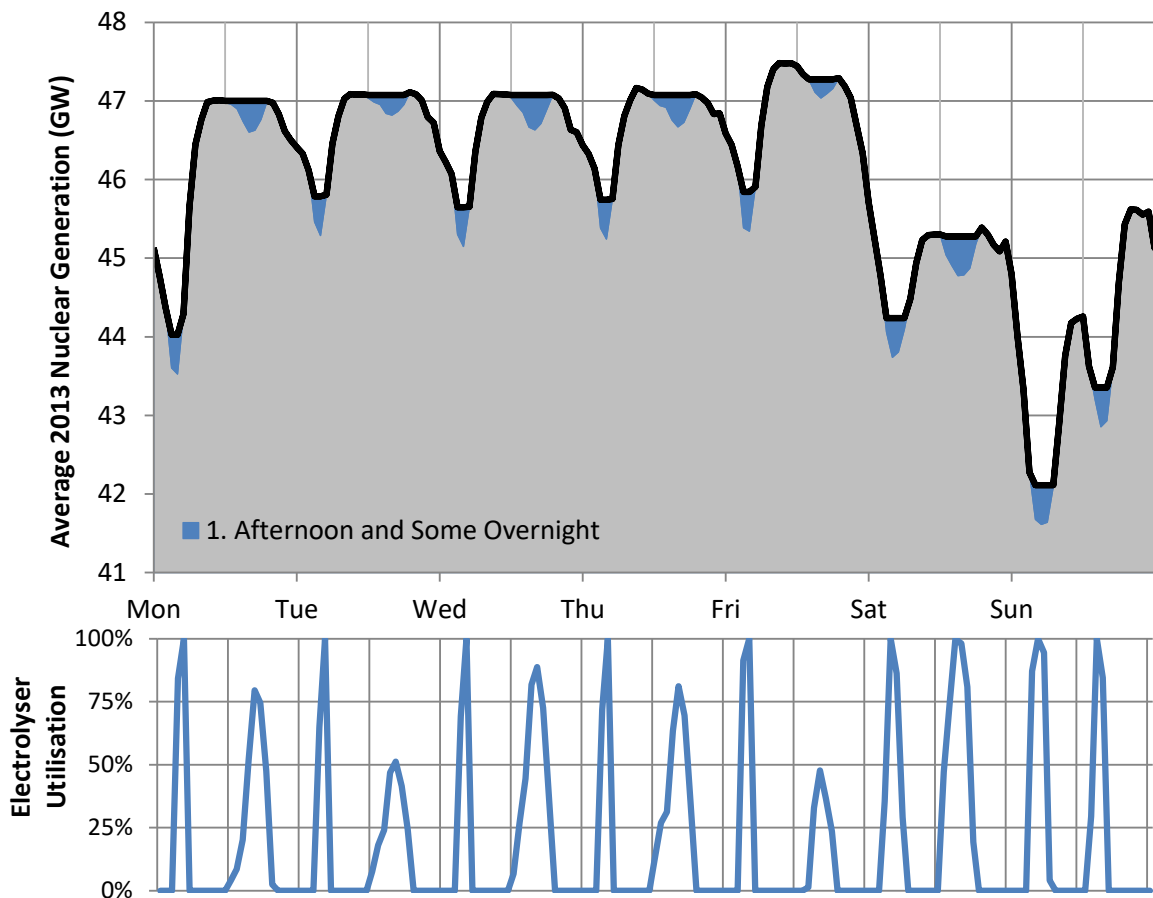
Figure 4: Average Summer and Winter Week Nuclear Power Generation Profiles in France [15]





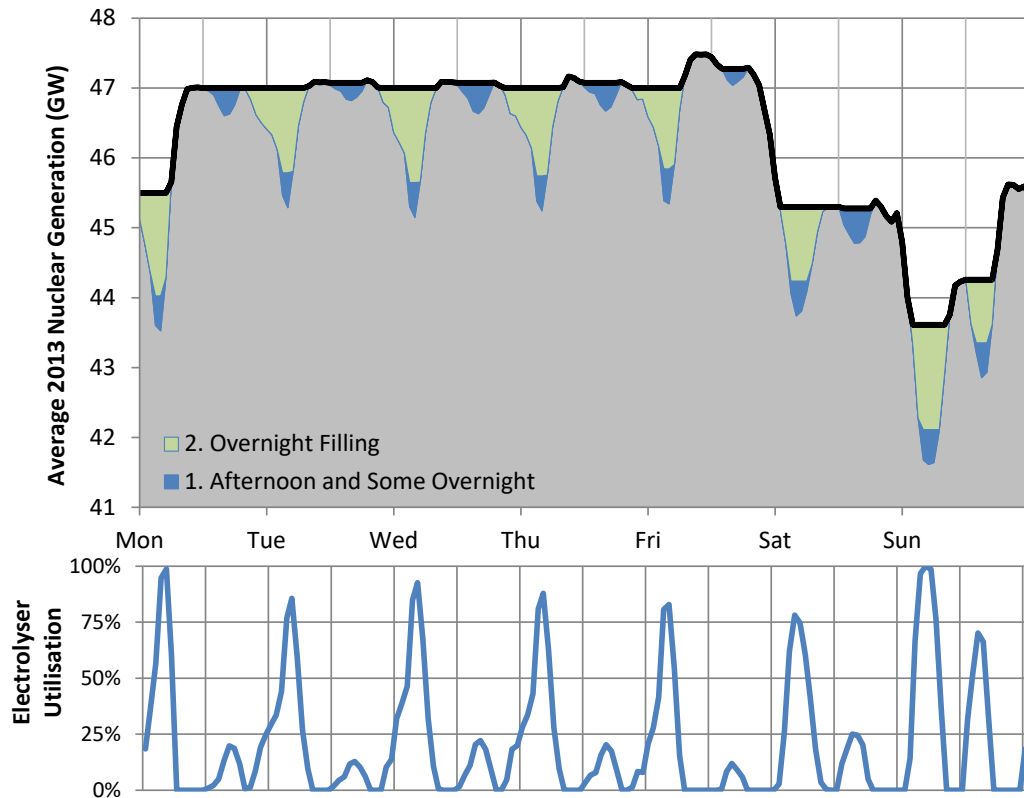
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Figure 5: Average Weekly Profile of Nuclear Production in France [15]



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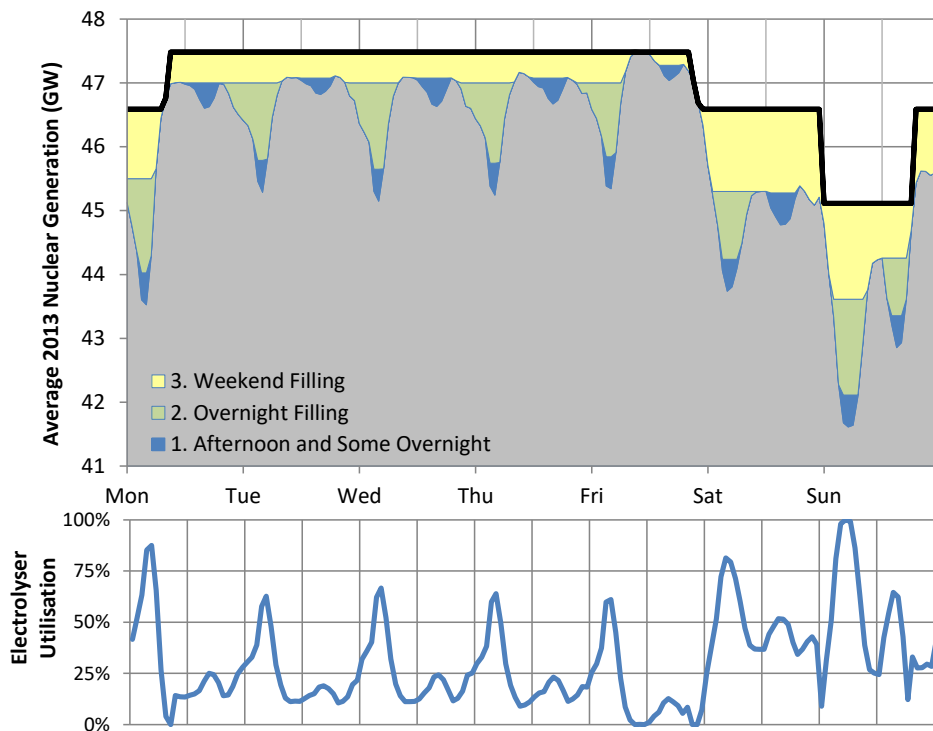
Figure 6: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 0.5GW of Electrolysis



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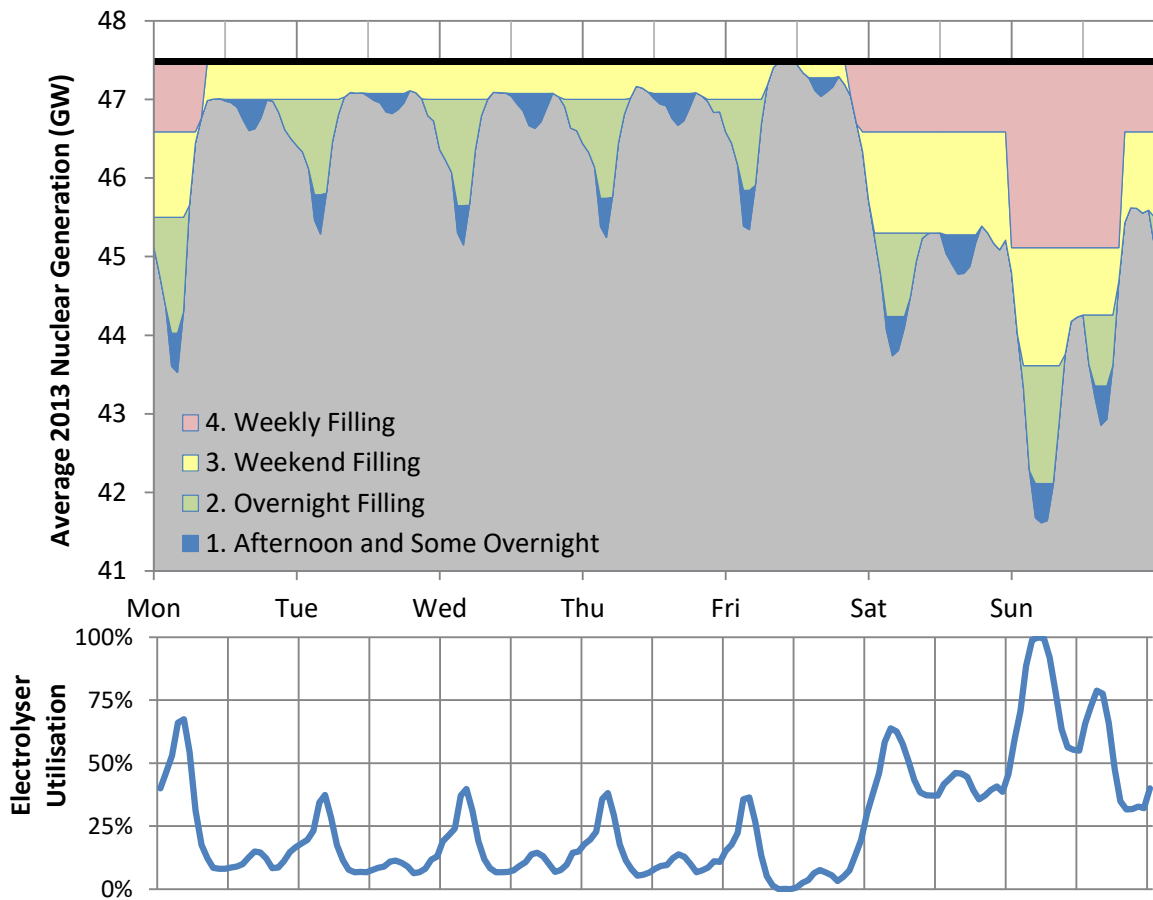
**Figure 7: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 2.0GW of Electrolysis**

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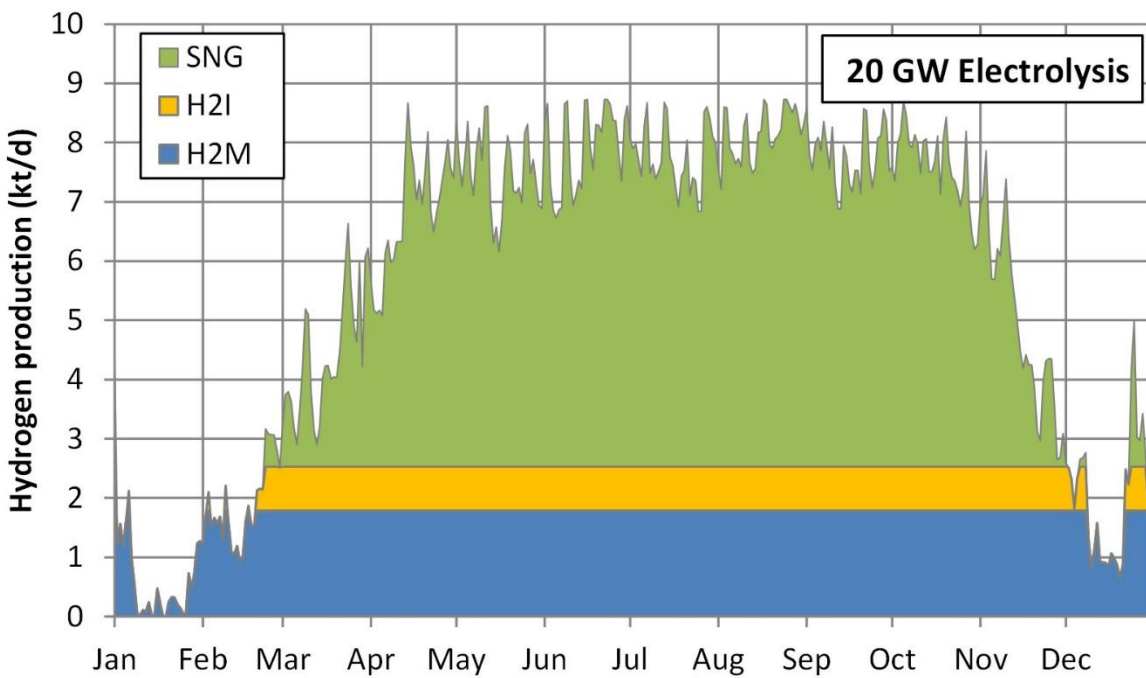


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**Figure 8: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 3.5GW of Electrolysis**

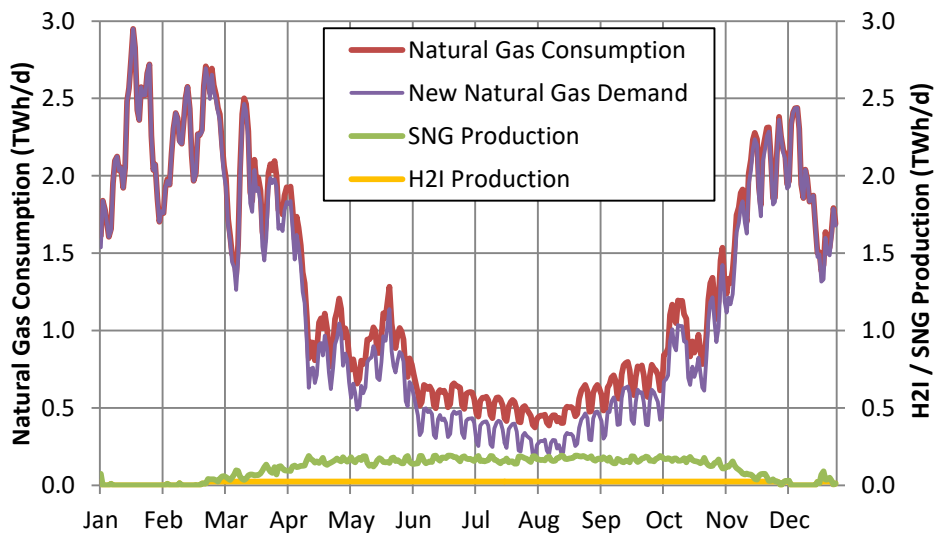


481 **Figure 9: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 6.0GW of**  
482 **Electrolysis**



485 **Figure 10: Operation of 20 GW of electrolysis to valley fill the 2013 nuclear generation profile**

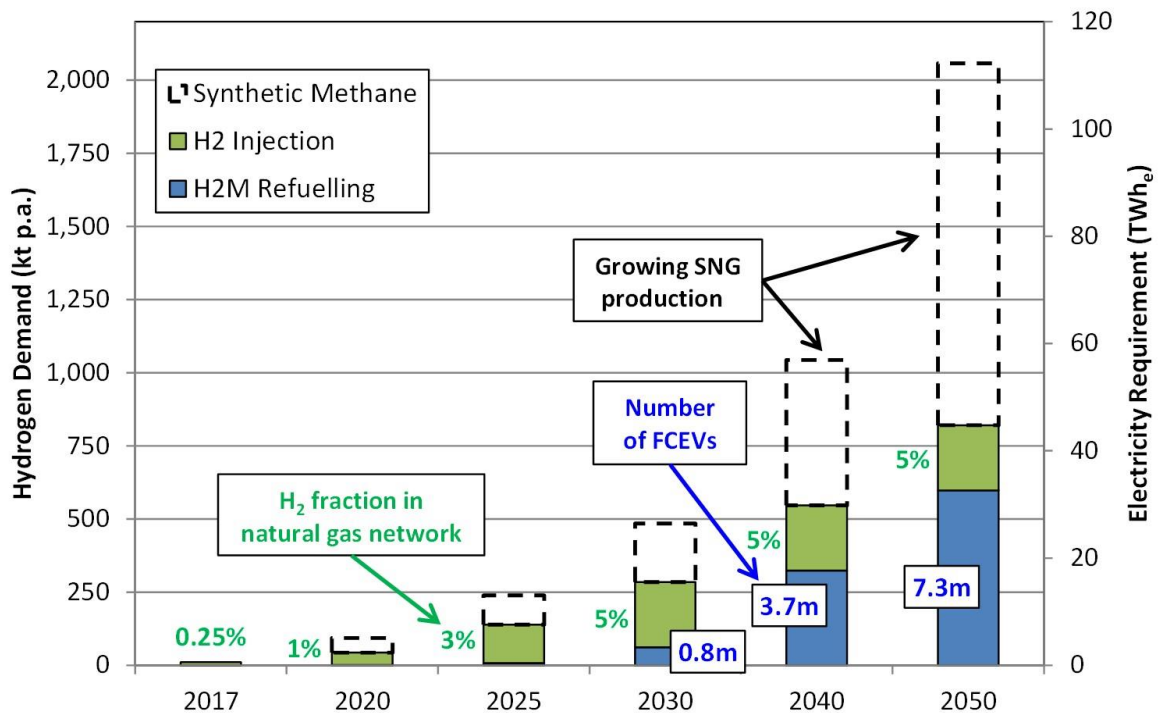
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488 **Figure 11: The effects of hydrogen and SNG injection as shown in Figure 10 on the 2013 demand profile for natural gas**

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492 **Figure 12: Applying Excess Nuclear Electricity to Hydrogen Mobility and Power-to-Gas Applications**

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