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 electrolysers 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 electrolysers. 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_2 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

1. Introduction

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

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

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

- injecting hydrogen (or synthetic methane derived from hydrogen and carbon dioxide) into the gas grid – usually referred to as 'power-to-gas'

- storing hydrogen in electrolyser-based Hydrogen Refuelling Stations (for refuelling fuel cell vehicles)

- storing hydrogen for example in salt caverns for power/heat generation.

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

This approach may be applied in many countries as a function of the availability, form and capacity of the gas grid, salt caverns and hydrogen mobility (H2M) infrastructure. In islands with relatively weak electricity grids, or regions with limited interconnections to neighbouring grids (e.g. the UK), the need to implement an indigenous solution must be faced at relatively low renewable power penetrations [12]. Conversely strong continental electricity grids can often transmit excess electricity to another region of lower renewable power penetration; for example, this currently occurs in Southern Germany due to the high solar PV penetration (Figure 1) [13]. However, for all regions, as the renewable or nuclear power penetration grows, it becomes increasingly desirable to utilise the excess electricity locally if curtailment is to be minimised.

France has a remarkably low carbon intensity for electricity generation of 61 gCO_2/kWh_e due to its large nuclear power capacity [14], but it remains heavily dependent on imported fossil fuels for providing heat and mobility. In 2013 transport fuel, natural gas and electricity requirements were similar, amounting to 494, 470 and 498 TWh respectively [15] [16] [17]. However, their demand characteristics vary significantly, with the gas demand profile exhibiting the greatest variation across the year (Figure 2). Outline consideration of Figure 2 suggests that the French transport and gas systems should be able to readily accommodate any surpluses emerging from the valleys of the national electrical load profile.

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

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

To help frame the opportunity for excess energy to be employed to enable hydrogen mobility and power-to-gas (P2G) in France, this investigation considered recent nuclear generation profiles. It made no attempt to predict future nuclear load profiles or to estimate future levels of excess nuclear electricity, which will be influenced both by the installed capacities of renewables and future electricity demand profiles.

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

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

2. Nuclear Generation Profiles

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

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

Weekly average nuclear power generation profiles for winter (Nov-Mar) and summer (Apr-Oct) for 2011-13 show regular patterns in the requirement placed on nuclear power plant across the day/week (Figure 4). Typically there are two daily valleys; a dip of about 0.5 GW in early afternoon, and a deeper valley of 1-2 GW overnight. In addition there is a deep weekend valley (including three nights, Friday to Sunday) of as much as 7 GW below the weekday peak. Weekend and night-time valleys are deeper in summer than in winter (7 GW versus 3 GW and 2 GW versus 1 GW respectively). These variations in the average load profiles are driven mainly by varying consumer/industrial behaviour patterns across the week and by weather variations across the year (e.g. different demand levels for electric heating, air conditioning and lighting).

3. Hydrogen Demand Predictions.

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

3.1 Mobility

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

A recent analysis for France called for 73% of the hydrogen consumed by FCEV in 2030 to be produced via on-site electrolysis in order to achieve a CO_2 saving of 77% relative to new diesel cars in 2030 [34]. It recommended that France itself construct an initial network of 55 hydrogen refuelling stations by 2020, rising to 600 by 2030. This could support 773,000 FCEVs by 2030, requiring 61.4 kt p.a. of hydrogen from electrolysis (~3.25 TWh_e p.a.) and a further 28.6 kt p.a. from reformed natural gas and chlor-alkali plant. By 2050, electrolytic hydrogen production for FCEV refuelling could rise considerably to 598 kt (requiring ~33 TWh_e per annum) for refuelling 7.3 million FCEVs.

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

3.2 Power-to-Gas

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

A large EU-funded project has indicated that properly-adjusted gas-fired appliances can accommodate volume concentrations of up to 20% hydrogen (given favourable natural gas quality), and pipelines could transport gas mixtures containing up to 50% hydrogen (depending on the pipeline steel used) [38]. Because gas consumption can vary by approximately one order of magnitude with time of day, some hydrogen buffer storage may be needed within the P2G plant depending on when the hydrogen is generated to ensure the concentration never exceeds 6%. However, it will not be feasible to achieve an average concentration of 6% at all times, because this would require an excessive amount of hydrogen storage. Therefore it was considered that average concentrations of <6% should be studied.

Electrolytic hydrogen and carbon dioxide may also be used to generate synthetic methane (SNG), and its injection to the natural gas grid is not restricted by permissible concentration limits. One recent analysis [35] reported that hydrogen injection in the French gas grid could capture 25 TWh of excess electricity per year. It predicted this growing to 75 TWh p.a. by 2050, which would require a combination of SNG-injection and hydrogen-injection. For SNG, it advocated the upgrading of biogas as the most cost effective route for sourcing the required CO_2. A further study [36] identified up to 13 TWh p.a. of excess electricity being available in France by 2030, and up to 67 TWh p.a. by 2050, which must be transferred out of the power system or lost (as opposed to absorbed by P2P storage technologies). The estimated requirement for P2G plant in France by 2030 was 1.2-1.4 GW, and up to 24 GW by 2050 [36]. The study called for 5-10% of the installed P2G capacity to be for H2I and the rest for SNG injection, with the CO_2 requirement supplied entirely from bio-renewable sources. Furthermore a multiple node model for power flows in NW European countries, has predicted 2030 curtailment levels of 5-10 TWh p.a. in each of France, Germany, Holland, Ireland and Denmark [37]. In general, the studies undertaken to date provide first order estimates of excess energy levels and they exclude excess nuclear - more detailed and independent predictions for future magnitudes and durations of excess renewables and excess nuclear are desirable.

The amounts of excess energy occurring in France depend on the assumed penetration levels of renewable and nuclear plant, but each of the above estimates is less than the current magnitude of excess nuclear. From the gas grid perspective, the existing 6% by volume limit for hydrogen means that up to about 9 TWh p.a. of hydrogen could be accommodated if appropriately administered, which would require ~13 TWh_e p.a. of excess electricity (assuming an average electrolyser efficiency of 70%). However, if excess energy is converted to SNG via the methanation of CO_2 and hydrogen, then the gas grid could absorb very large amounts (e.g. potentially up to the current natural gas consumption level of ~470TWh p.a.). These outline considerations frame the P2G opportunity and indicate that this already available sink for excess electricity could enable France to adopt a high nuclear and high renewables decarbonisation strategy, where the respective installed capacities far exceed the national peak power demand.

3.3 Storage with Reconversion to Electricity

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

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 electrolysers 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_2 p.a. (or an electricity input of about 12.3 $TWh_{e.}$). Similarly if as predicted the mobility demand reaches 598 kt H_2 p.a. by 2050 [34], the combined H2I and H2M electricity requirements for electrolysis would then be ~45 TWh_e 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.

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

Installed Electrolysis Capacity (GW)	Electrolyser Energy Utilisation (%)	Electrolyser Run Time (h p.a.)	Degree of 'Valley Filling'	Hydrogen Production (kilo-tonnes H_2 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

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

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

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

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

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

4.2 Valley-Filling of Annual Profiles

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

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

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

5. Conclusions

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

A progressive deployment of electrolysers that reaches 20 GW by 2050 is identified as being a most expedient implementation for utilising excess nuclear electricity. A deployment of about 6 GW by 2030 would substantially flatten the average weekly load profile placed on existing nuclear plant, and so simplify operation and maximise the return on investment. It would provide sufficient fuel to easily meet the predicted hydrogen mobility requirement and make a significant contribution to the gas sector. Annual hydrogen yields may be augmented further by absorbing excess renewable power when it occurs out of time phase with excess nuclear.

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

References

[1] E. Troncoso and M. Newborough, "Electrolysers as a load management mechanism for power systems with wind power and zero-carbon thermal power plant," *Applied Energy,* vol. 87, pp. 1-15, 2010.

[2] P. Finn and C. Fitzpatrick, "Demand side management of industrial electricity consumption: promoting the use of renewable energy through real-time pricing," *Applied Energy,* vol. 113, pp. 11-21, 2014.

[3] D. J. Burke and M. J. O'Malley, "Factors influencing wind energy curtailment," *IEEE Trans on Sustainable Energy,* vol. 2, no. 2, pp. 185-193, 2011.

[4] Fuel Cells and Hydrogen Joint Undertaking, "Commercialisation of Energy Storage in Europe: A fact-based analysis of the implications of projected development of the European electric power system towards 2030-2050 for the role and commercial viability of energy storage," FCH-JU, Brussels, 2015.

[5] C. J. Bennett, R. A. Stewart and J. W. Lu, "Development of a three-phase energy storage scheduling and operation system for low voltage distribution networks," *Applied Energy,* vol. 146, pp. 122-134, 2015.

[6] J. Vandewalle, K. Bruninx and W. D'Haeseleer, "Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions," *Energy Conversion and Management,* vol. 94, pp. 28-39, 2015.

[7] S. Schiebahn, T. Grube, M. Robinius, V. Tietze, B. Kumar and D. Stolten, "Power to gas: technological overview, systems analysis and economic assessment for a case study in Germany," *IJ Hydrogen Energy,* vol. 40, pp. 4285-4294, 2015.

[8] A. Varone and M. Ferrari, "Power to liquid and power to gas: an option for the German Energiewende," *Renewable and Sustainable Energy Reviews,* vol. 45, pp. 207-218, 2015.

[9] F. Gutierrez-Martin and I. Guerrero-Hernandez, “Balancing grid loads by large scale integration of hydrogen technologies: the case of the Spanish power system,” *IJ Hydrogen Energy,* vol. 37, pp. 1151-1161, 2011.

[10] G. Gahleitner, “Hydrogen from renewable electricity: an international review of power-to-gas pilot plants for stationary applications,” *IJ Hydrogen Energy,* vol. 38, pp. 2039-2061, 2013.

[11] California Independent System Operator (CAISO), “What the Duck Curve tells us about managing a green grid,” 2013. [Online]. Available: http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. [Accessed August 2014].

[12] E. Troncoso and M. Newborough, “Implementation and control of electrolysers to achieve high penetrations of renewable power,” *IJ Hydrogen Energy,* vol. 32, no. 13, pp. 2253-2268, 2007.

[13] Agora Energiewende, “Agorameter: Stromerzeugung und Stromverbrauch,” 2014. [Online]. Available: http://www.agora-energiewende.de/service/aktuelle-stromdaten/?tx_agoragraphs_agoragraphs%5BinitialGraph%5D=powerGeneration&tx_agoragraphs_agoragraphs%5Bcontroller%5D=Graph. [Accessed July 2014].

[14] International Energy Agency, “CO2 Emissions From Fuel Combustion: Highlights,” 2013. [Online]. Available: http://www.iea.org/publications/freepublications/publication/CO2EmissionsFromFuelCombustionHighlights2013.pdf. [Accessed August 2014].

[15] Réseau de Transport d’Électricité (RTE), “Production réalisée par le parc de référence,” [Online]. Available: http://clients.rte-france.com/lang/fr/visiteurs/vie/prod/realisation_production.jsp. [Accessed August 2014].

[16] GRTGaz, “Gas Consumption Data,” [Online]. Available: http://www.smart.grtgaz.com/en/consommation. [Accessed August 2014].

[17] Ministère de l’Écologie, du Développement Durable et de l'Énergie, “Bulletin mensuel statistique des transports,” [Online]. Available: http://www.statistiques.developpement-durable.gouv.fr/transports/873.html. [Accessed August 2014].

[18] Réseau de Transport d’Électricité (RTE), “Daily import/export balance France,” 2013. [Online]. Available: http://clients.rte-france.com/lang/an/visiteurs/vie/interconnexions/all_histo/capa_bilan.jsp. [Accessed February 2015].

[19] Réseau de Transport d’Électricité (RTE), “Bilan électrique 2013,” 2014. [Online]. Available: http://www.rte-france.com/uploads/Mediatheque_docs/vie_systeme/annuelles/Bilan_electrique/bilan_electrique_2013.PDF. [Accessed February 2015].

[20] World Nuclear Association, “Nuclear Power in France,” 2014. [Online]. Available: http://www.world-nuclear.org/info/Country-Profiles/Countries-A-F/France/. [Accessed February 2015].

[21] International Hydropower Association, “2013 IHA Hydropower Report,” 2013. [Online]. Available: http://www.hydropower.org/sites/default/files/publications-docs/2013%20IHA%20Hydropower%20Report.pdf. [Accessed February 2015].

[22] European Wind Energy Association (EWEA), “Wind in power: 2013 European statistics,” 2014. [Online]. Available: http://www.ewea.org/fileadmin/files/library/publications/statistics/EWEA_Annual_Statistics_2013.pdf. [Accessed February 2015].

[23] European Photovoltaic Industry Association (EPIA), “Global Market Outlook For Photovoltaics 2014-2018,” 2014. [Online]. Available: http://www.epia.org/fileadmin/user_upload/Publications/EPIA_Global_Market_Outlook_for_Photovoltaics_2014-2018_-_Medium_Res.pdf. [Accessed February 2015].

[24] Climate Action Programme, “France approves historic energy transition bill,” 2015. [Online]. Available: http://www.climateactionprogramme.org/news/france_approves_historic_energy_transition_bill. [Accessed April 2016].

[25] Electricite de France (EdF), “Load Following: EdF Experience Feedback,” in *IAEA Technical Meeting - Load Following*, Paris, September 4-6, 2013.

[26] M. Lykidi and P. Gourdel, “How to manage flexible nuclear power plants in a deregulated electricity market from the point of view of social welfare?,” *Energy,* vol. 85, pp. 167-180, 2015.

[27] P. Denholm, J. C. King, C. F. Kutcher and P. P. H. Wilson, “Decarbonizing the electric sector: combining renewable and nuclear energy using thermal storage,” *Energy Policy,* vol. 44, pp. 301-311, 2012.

[28] A. Lokhov, “Technical and economic aspects of load following with nuclear power plants,” Nuclear Energy Agency, Organisation for Economic Co-operation and Development, 2011.

[29] P.-H. Floch, S. Gabriel, C. Mansilla and F. Werkoff, “On the production of hydrogen via alkaline electrolysis during off-peak periods,” *International Journal of Hydrogen Energy,* vol. 32, no. 18, pp. 4641-4647, 2007.

[30] F. Gutiérrez-Martín, J. M. García-De María, A. Baïri and N. Laraqi, “Management strategies for surplus electricity loads using electrolytic hydrogen,” *International Journal of Hydrogen Energy,* vol. 34, no. 20, pp. 8468-8475, 2009.

[31] S. Bennoua, A. Le Duigou, M.-M. Quéméré and S. Dautremont, “Role of hydrogen in resolving electricity grid issues,” *International Journal of Hydrogen Energy,* vol. 40, no. 23, pp. 7231-7245, 2015.

[32] R. G. M. Crockett, M. Newborough, D. J. Highgate and S. D. Probert, “Electrolyser-based electricity management,” *Applied Energy,* vol. 51, pp. 249-263, 1995.

[33] International Atomic Energy Agency, “Country Nuclear Power Profiles - France,” IAEA, Vienna, 2015.

[34] Mobilité Hydrogène France, “H_2 Mobilité France: study for a FCEV national deployment plan,” October 2014. [Online]. Available: http://www.afhypac.org/images/documents/h2_mobilit_france_en_final_updated.pdf. [Accessed February 2015].

[35] E-Cube, “Analysis of the role of natural gas transportation in the hydrogen economy in France: report to GRTGaz,” Paris, 2013.

[36] ADEME, GRTGaz and GRDF, “Study of hydrogen and methanation as processes for capturing the value of excess electricity,” September 2014.

[37] T. Slot and P. Van der Wijk, “Extended Flexibility Study: Power to Gas Potential in 2025 and 2030,” DNVGL, Report 7410609.002-MPD/MAR 14-3286, 2014.

[38] NaturalHy, “Final Publishable Activity Report,” 2010.

[39] J. Nitsch and C. Voigt, “Launch concepts for non-fossil hydrogen,” in *Hydrogen as an Energy Carrier: Technologies, Systems, Economy*, C. J. Winter and J. Nitsch, Eds., Springer-Verlag, 1988, p. 300.

[40] GRTGaz, “Prescriptions Techniques applicables aux canalisations de Transport de GRTgaz,” 2007. [Online]. Available: http://www.grtgaz.com/fileadmin/clients/consommateur/documents/raccordement_donnees-prescriptions_fr.pdf.

[41] Légifrance, “Décret n°2004-555 du 15 juin 2004 relatif aux prescriptions techniques applicables aux canalisations et raccordements des installations de transport, de distribution et de stockage de gaz,” 2004. [Online]. Available: http://www.legifrance.gouv.fr/affichTexte.do?cidTexte=LEGITEXT000005787167. [Accessed February 2015].

[42] HyUnder, “Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe,” 2014. [Online]. Available: http://www.hyunder.eu/images/Deliverables/D6%203_Joint%20results%20from%20individual%20case%20studies%202.pdf. [Accessed February 2015].

[43] A. Gillhaus, “Natural Gas Storage in Salt Caverns - Present Status, Developments and Future Trends in Europe,” 29 April - 2 May, 2007. [Online]. Available: http://www.innovativeenergy.com.au/saltcavern/Europe%20salt%20caverns.pdf. [Accessed February 2015].

[44] Total Infrastructures Gaz France (TIGF), “Offrir un service de stockage souterrain de gaz naturel du Grand Sud-Ouest à l’Europe,” 2010. [Online]. Available: http://www.tigf.fr/fileadmin/Nos_publications/Publications_institutionnelles/PDF/Offrir-un-service-de-stockage.pdf.

[45] M.-L. Heddrich, T. Lenck and C. P. Linkenheil, “Wind power as an alternative to nuclear power from Hinkley Point C: a cost comparison,” Greenpeace Energy in Germany, Berlin, 2016.

Figures

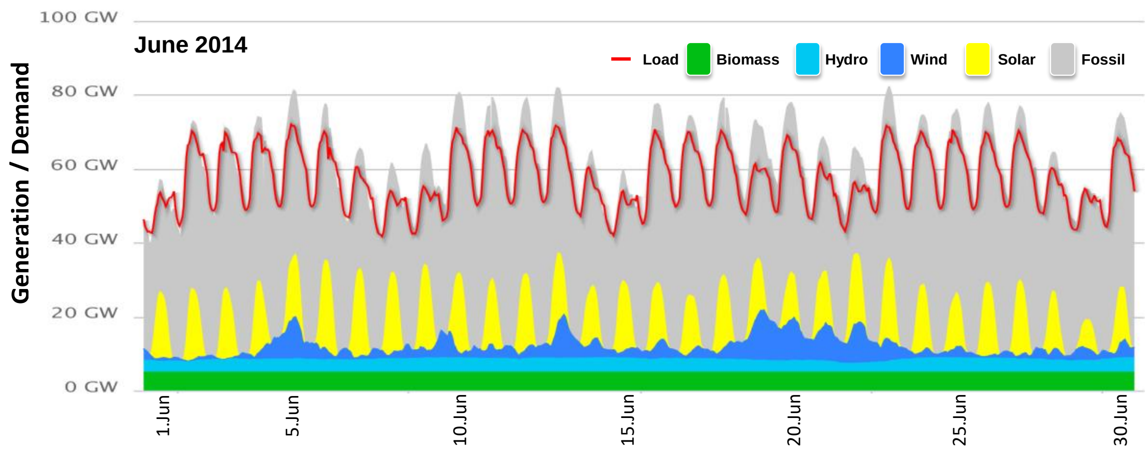

Figure 1: Solar power in Germany causing excess energy to be exported to neighbouring countries or curtailed [13]

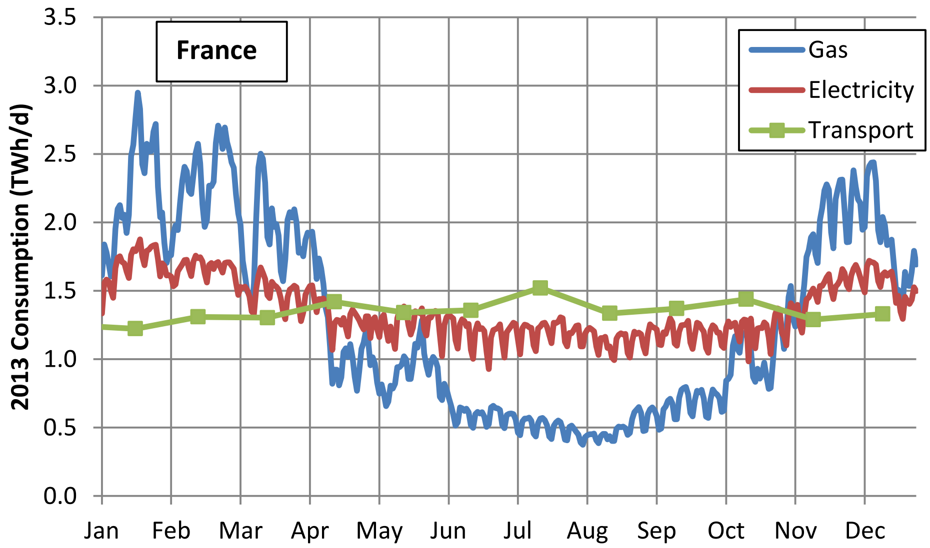

Figure 2: Energy consumption in France for Gas, Electricity and Transport Fuel (total diesel and petrol deliveries) [15] [16] [17]

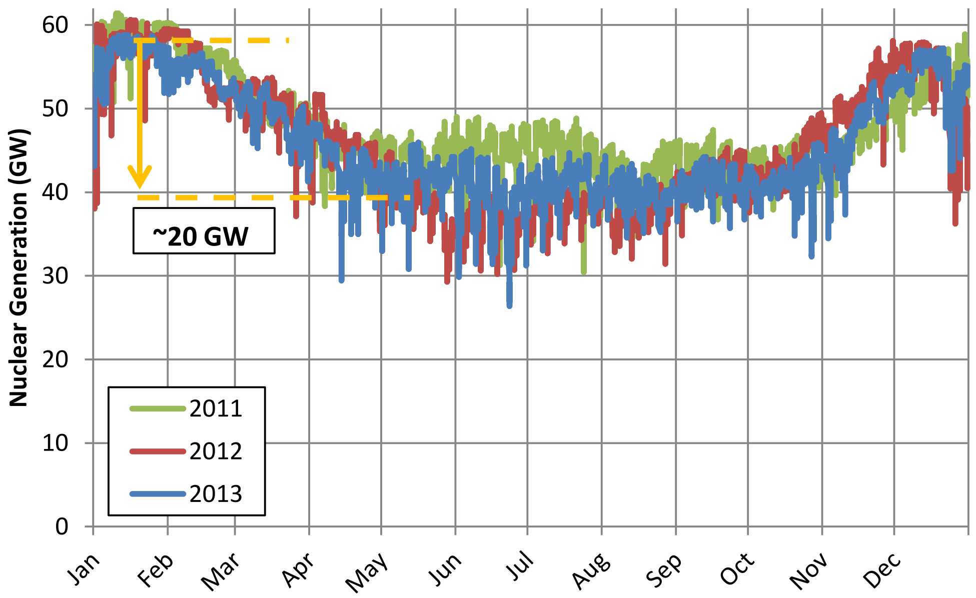

Figure 3: French nuclear generation variation 2011-13 [15]

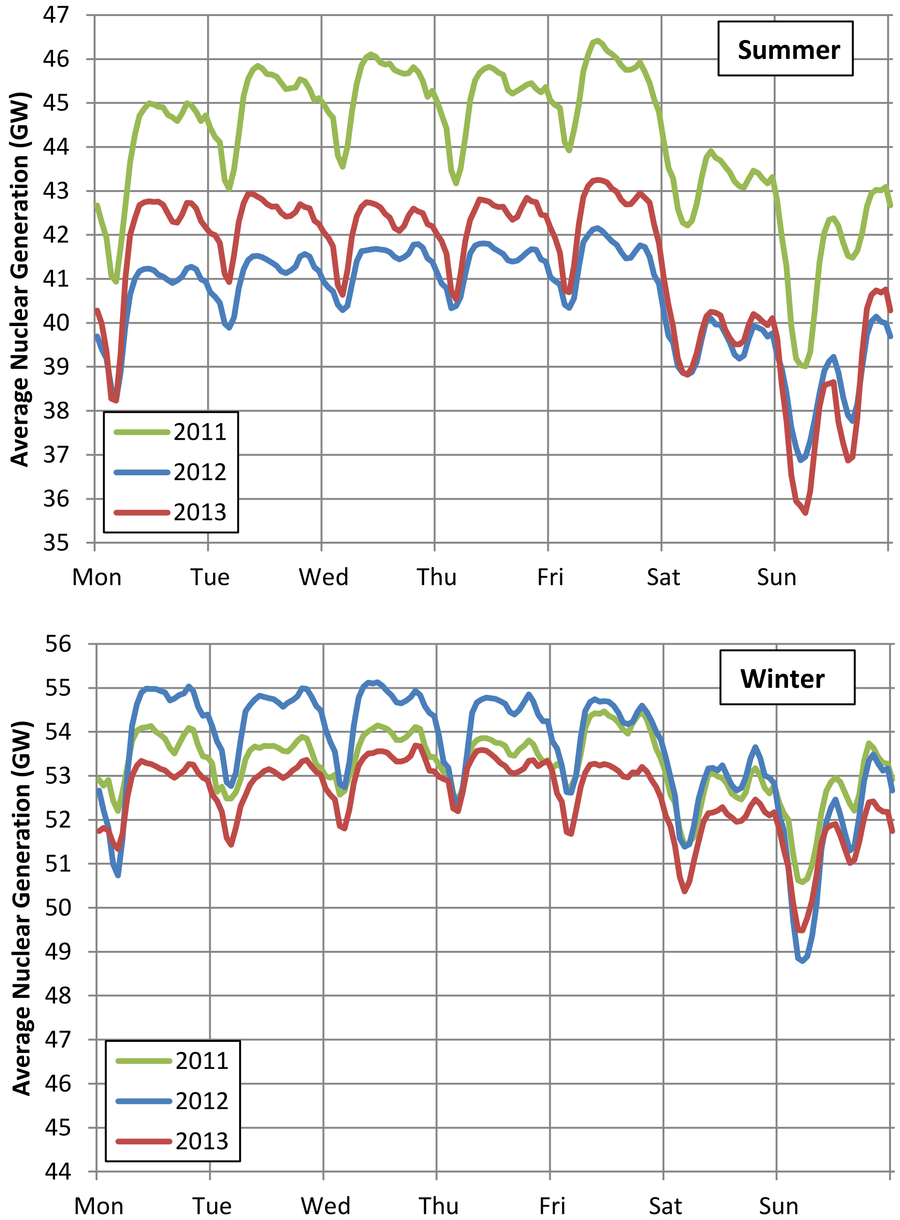

Figure 4: Average Summer and Winter Week Nuclear Power Generation Profiles in France [15]

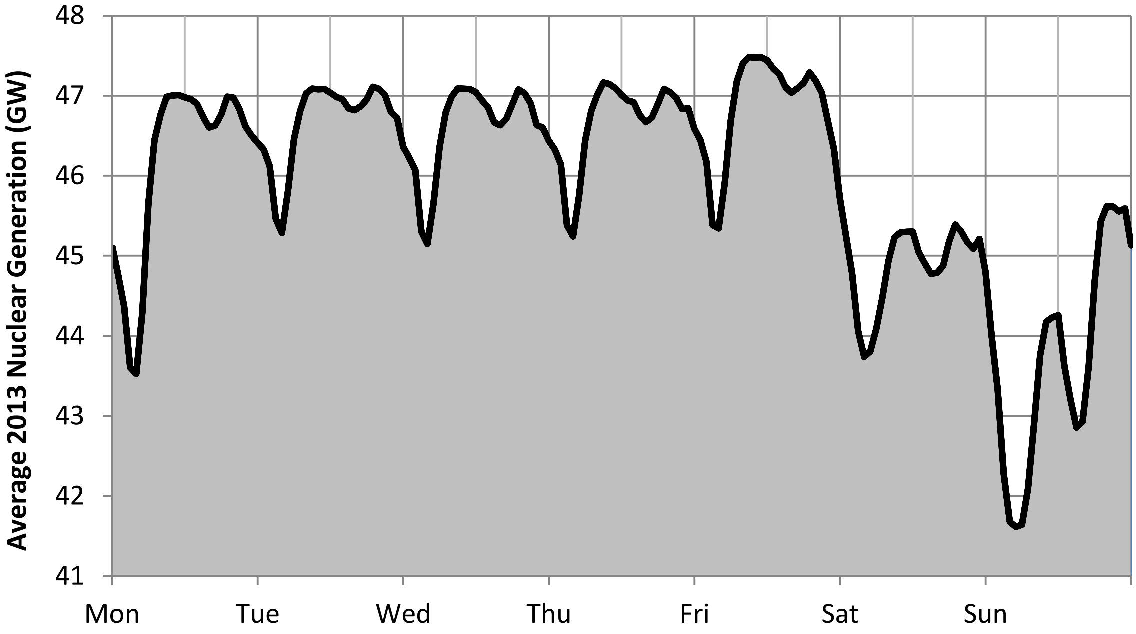

Figure 5: Average Weekly Profile of Nuclear Production in France [15]

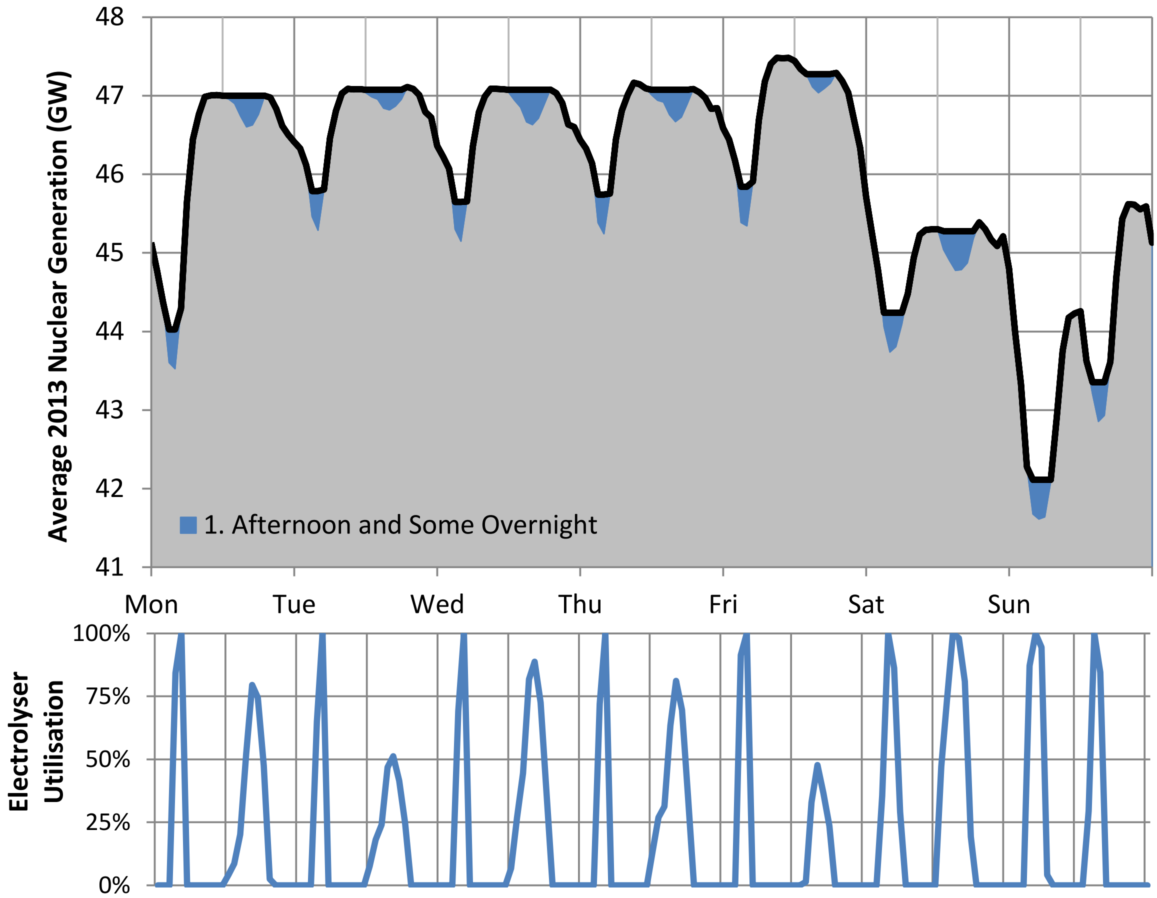

Figure 6: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 0.5GW of Electrolysis

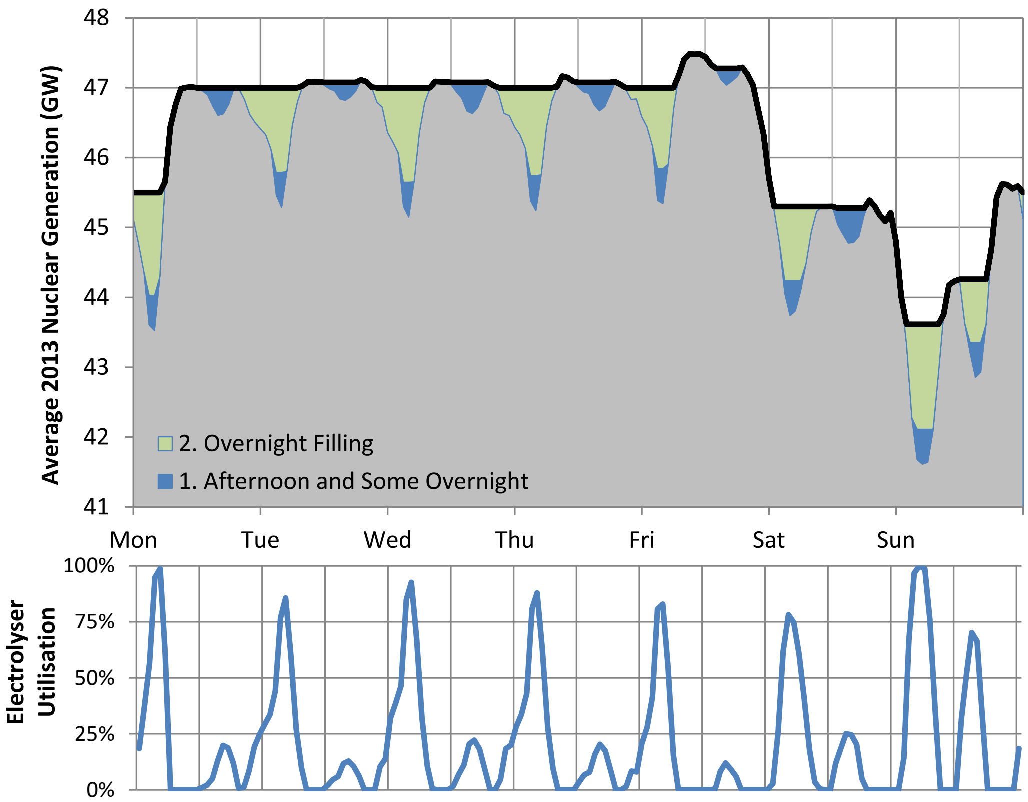

Figure 7: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 2.0GW of Electrolysis

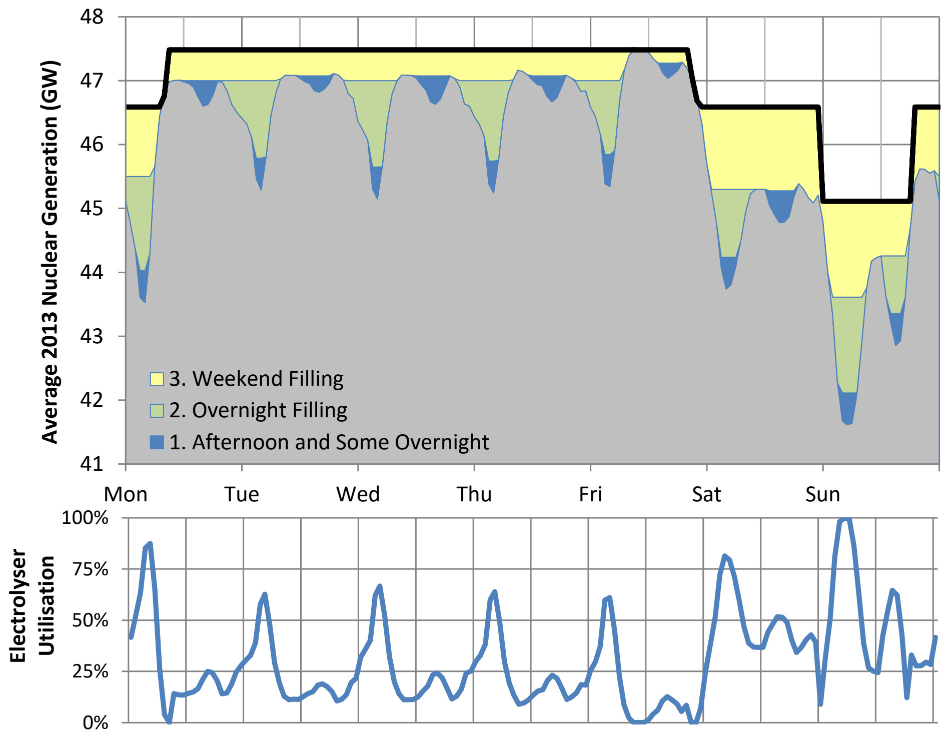

Figure 8: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 3.5GW of Electrolysis

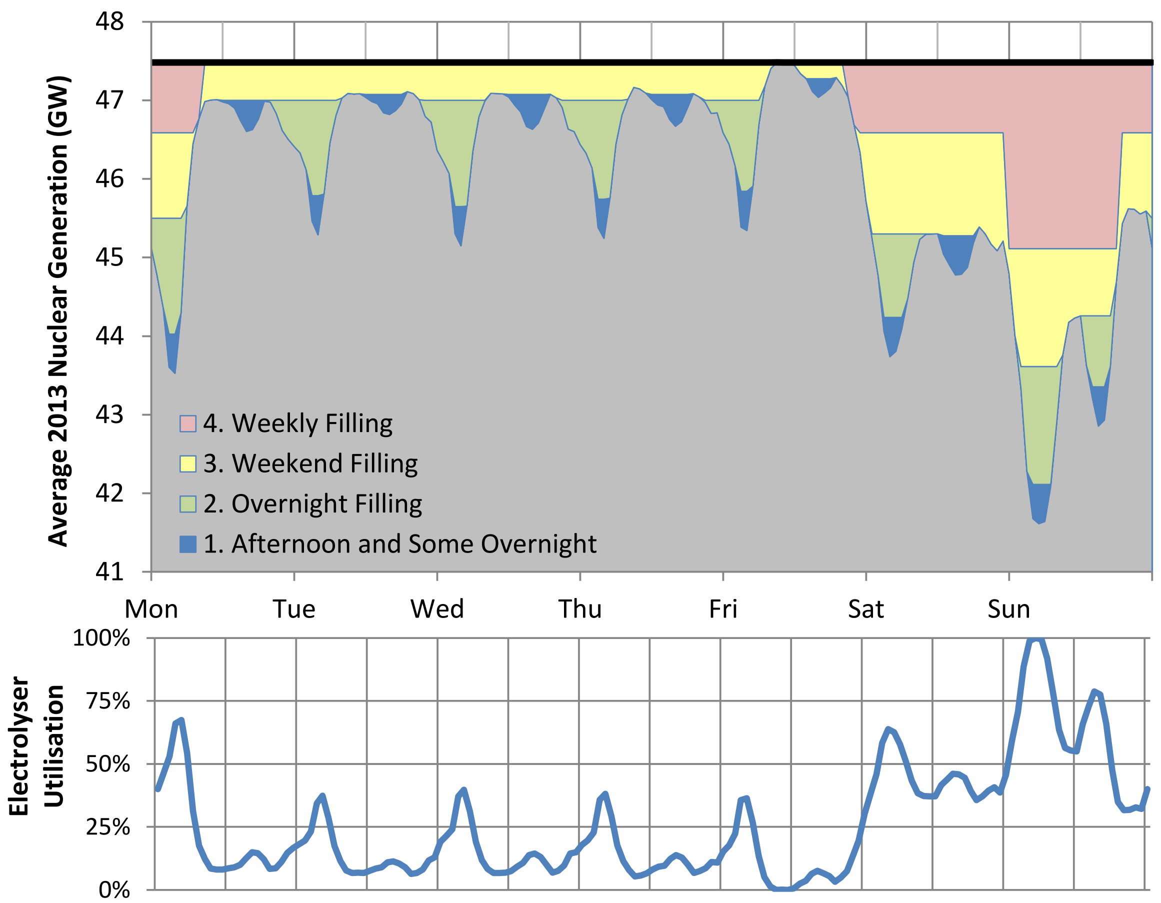

Figure 9: Average Weekly Profile of Nuclear Production and Electrolyser Utilisation for 6.0GW of Electrolysis

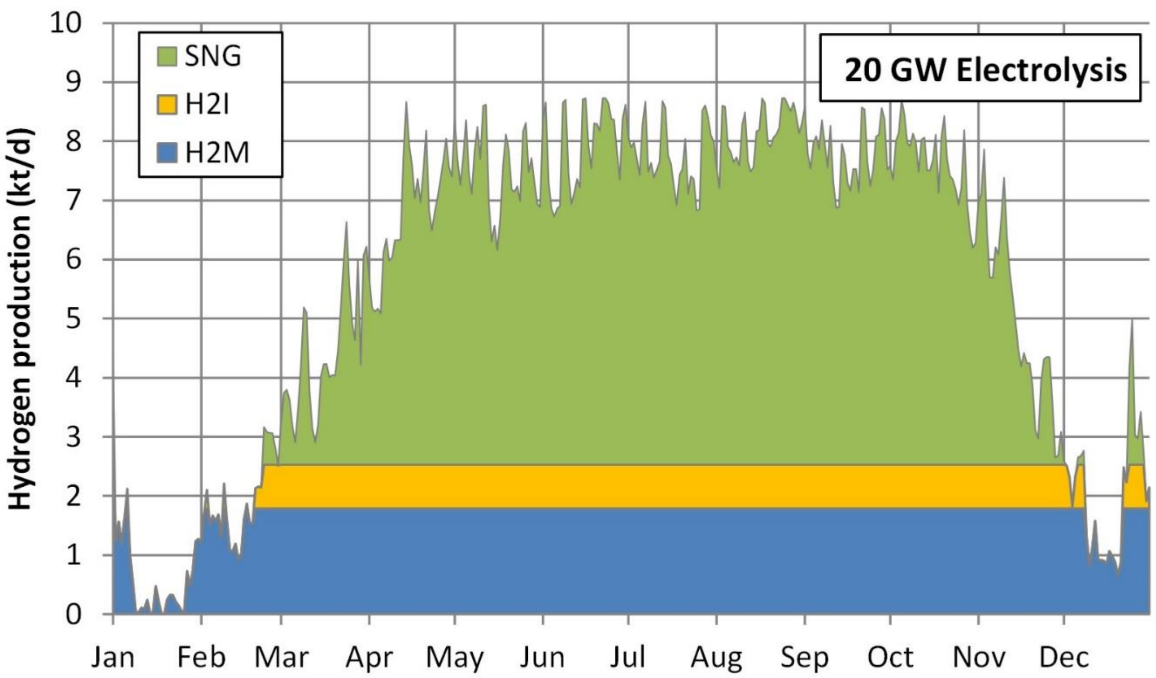

Figure 10: Operation of 20 GW of electrolysis to valley fill the 2013 nuclear generation profile

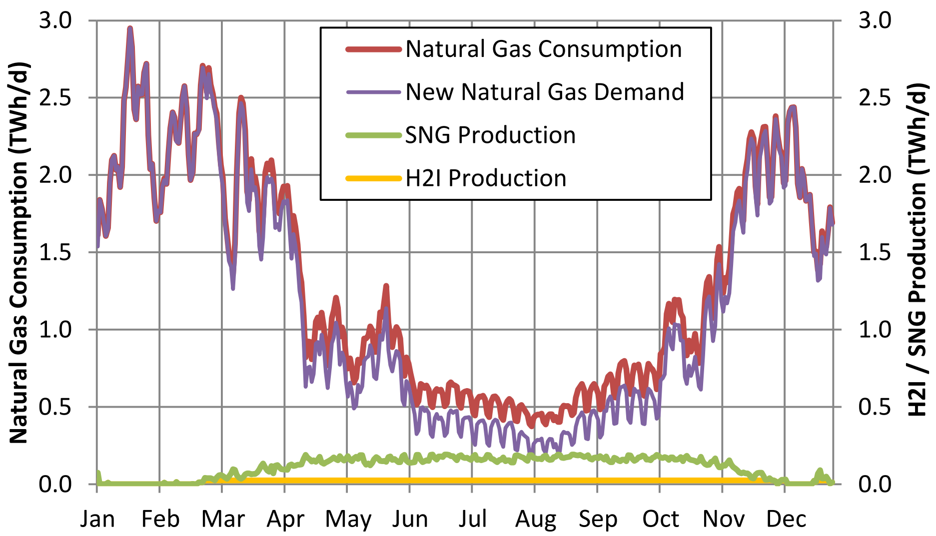

Figure 11: The effects of hydrogen and SNG injection as shown in Figure 10 on the 2013 demand profile for natural gas

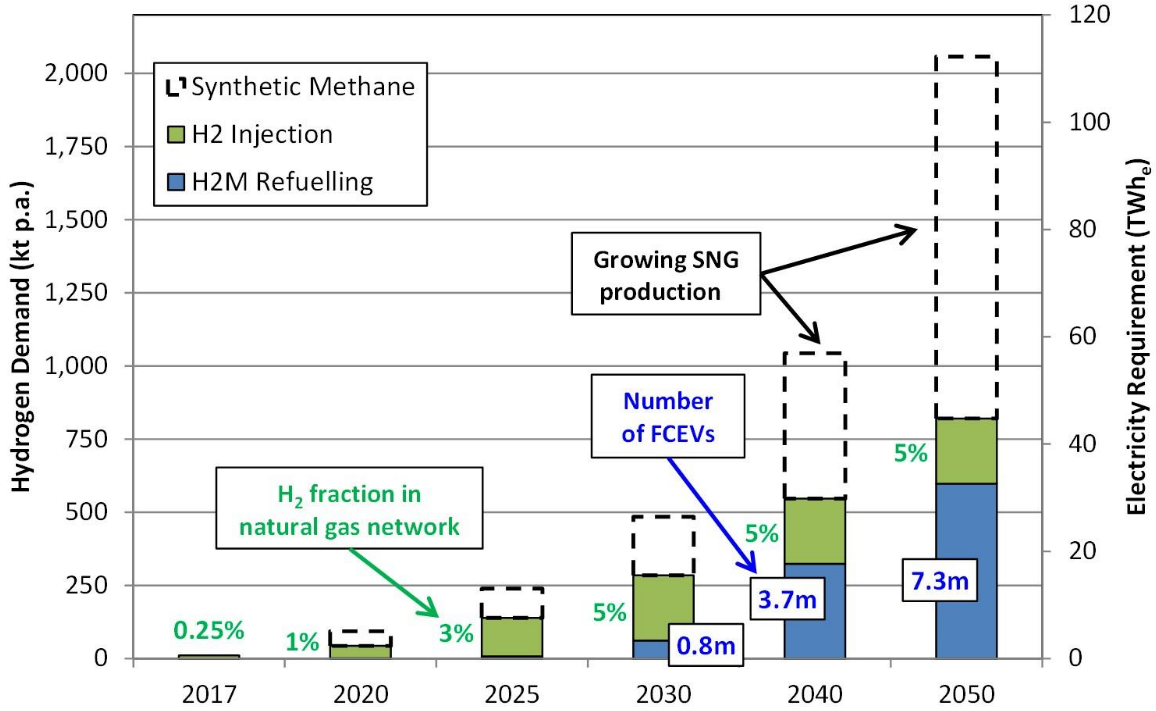

Figure 12: Applying Excess Nuclear Electricity to Hydrogen Mobility and Power-to-Gas Applications