Storage of Renewable Energy as Hydrogen on the Gas Grid. Is It a Workable Proposition?

Earlier this year an article[1] appeared in Renewable Energy World quoting a report from Bloomberg which suggested that hydrogen produced from "surplus" electricity can be stored in the gas grid. This proposal is one of many which purports to provide an energy storage solution for "surplus" electricity generated by renewable sources. The driver for this proposal comes as the result of the non-dispatchability of renewable electricity generation as a method to accommodate the variability of, for example, wind power. While this proposal may appear to furnish a simple solution to the renewable hydrogen storage dilemma, it has quite a few hidden pitfalls.

The storage of renewable generated hydrogen in the gas grid is not a new idea. The concept has been proposed in Germany[2], reported by Florian Leucht at ICEPAG in 2014 at UC Irvine[3], and more recently in the Polish literature[4]. These references are not to meant to an exhaustive recounting of the literature but to serve as gateway starting points for further investigation.

BACKGROUND:

Many legal jurisdictions around the world, e.g., California and Germany, have legislated mandatory renewables content for their energy portfolios. California has an ambitious schedule of 25% by 2016 (end of & met) and 33% by 2020[5]. Germany's portfolio standards are just as aggressive with 33% renewable content for electricity and 20% renewable content for all energy components in place by 2020[6].

In the mix of capital equipment used for generation of renewable energy, wind power has garnered the lowest cost per kW of generation capacity. However, wind power is not dispatchable owing to the capricious nature of "every which way the wind blows". The variance in wind energy production as a function of time of day can be seen in the figure below. The data are from the Tehachapi wind farm with a 5200 MW nameplate capacity and were recorded in 2010[7]. The other phenomenon of note in this figure is the timing of the peak production of the wind power in California. Invariably, it occurs at night, in a pattern almost exactly opposed to the daily electricity demand curve.

1 [1]Renewableenergyworld.com/articles/2018/05/hydrogen-may-rival-batteries-for-uk-s-renewable-energy.html

2 F. Leucht, W. G. Bessler, J. Kallo, K. A. Friedrich and H. Müller-Steinhagen, Fuel Cell System Modelling for SOFC/GT Hybrid Power Plants, Part I: Modelling and simulation framework, Journal of Power Sources, 196, (2011) 1205-1215.

3 ICEPAG AT UC Irvine 2014; author was present at this meeting and attended the presentation.

4 DOI: 10.1051/e3sconf/20171401045

5 http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm

6 http://en.wikipedia.org/wiki/Renewable_portfolio_standard

7 http://www.caiso.com/1bed/1bede3f55a320.pdf

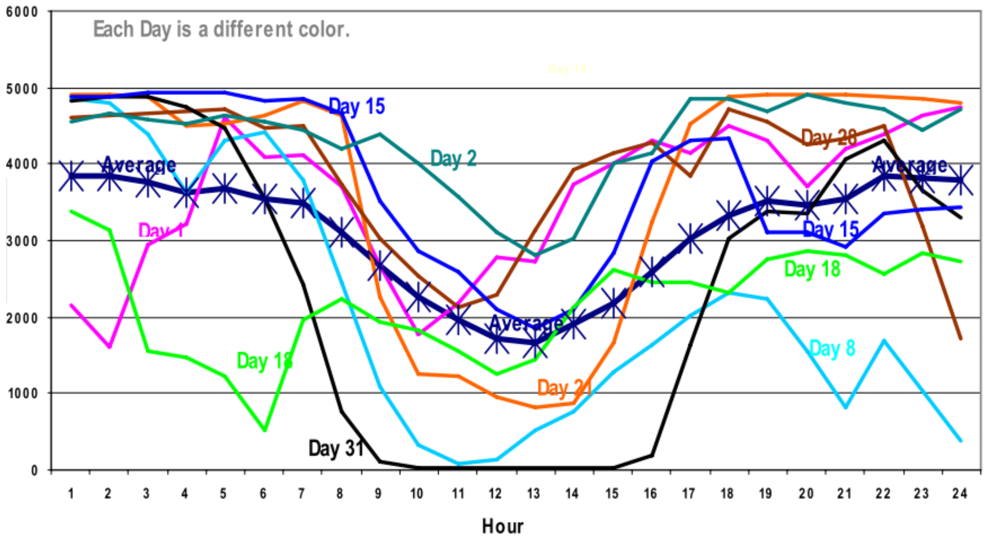


Figure: Catalog of observed wind velocities over one month at
The 5,200 MW wind farm in Tehachapi California

Owing to the mandated renewable's acceptance requirements, the grid operator in CA, CA ISO, is required to purchase this wind generated energy. As the wind energy component is not dispatchable, the CA ISO must have some fossil fuel plants on standby in order to maintain the grid integrity, if and (surely) when the wind sources fade, as they will. Full integration of this wind resource should have some storage capability for the wind energy and/or more sophisticated weather (wind) forecasting ability to provide at least a 5-10 minute prediction window for wind performance[8] to allow for initiation of the backup generation sources.

Storage Possibilities for Non-dispatchable Renewables

Of course, when ever the question of electricity storage arises, one's immediate thoughts go to batteries. However, batteries will not be considered here as they are not yet ready for wide scale deployment as an economical grid scale storage solution, they are still too costly. Another grid scale storage solution is afforded by pumped storage. While an attractive solution to the problem, pumped storage is constrained by geographical constraints and is not considered here. Beginning in 2013 several companies in Germany, most notably, E.ON, proposed to use electrolytic hydrogen as a storage vehicle for this excess renewable energy[9]. Energy storage built upon electrolytic hydrogen was the premise of the Bloomberg report and the main driver for this paper.

Hydrogen Generation for Storage of Excess Renewable Energy

The concept of excess renewable electricity is meant to describe the generation of renewable electricity in quantities that are unable to be used by the utility owing to lack of demand on its grid. One solution that has been used is that the utility offers this surplus power to other energy users outside of its own grid at often negative

[8] A 5-10 minute window would match the startup capability of the Wartsila ICE generators.
[9] https://en.wikipedia.org/wiki/Power-to-gas

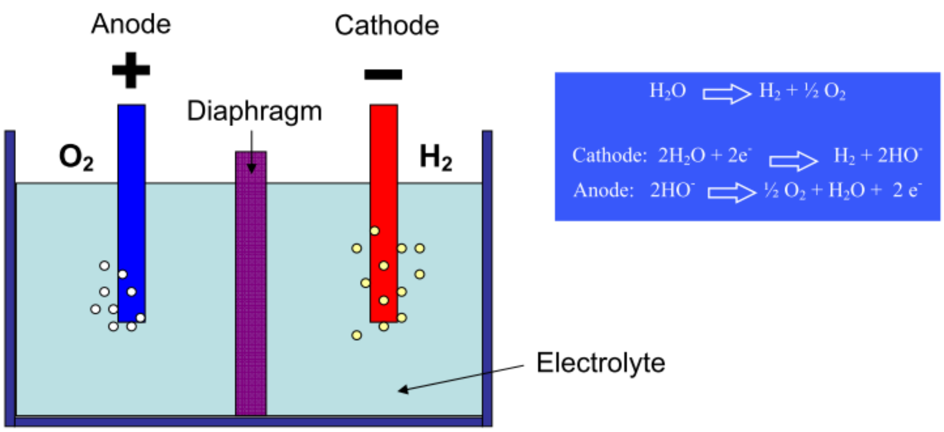
pricing, “Take my electricity, please”. Here we’ll look at electrolytic hydrogen generation, storage options, and, some applications.

Hydrogen Electrolyzers for Conversion of Electricity into Gaseous Hydrogen

The electrolysis of water with DC electricity is an old process as it was demonstrated by Michael Faraday in the 1830’s. The products of the passage of DC electricity through water are hydrogen and oxygen. There are several major suppliers of commercial water electrolyzers which have been around for many years. A short review of this technology will be given here, a more extensive review of electrolyzers can be found on my website[10].

Technology of the Water Electrolyzer

Water electrolysis is an electrochemical process in which a DC electric current is passed through water. A very simple representation of the process is shown below[11]. Hydrogen is liberated at the cathode and oxygen is liberated at the anode. (The diaphragm is very important to keep the gases separate for safety reasons.) Hydrogen, the desired product, is captured, compressed, and, stored or used directly. The oxygen is usually vented unless a willing local customer is available.



There are 2 major types of electrolyzers, alkaline and PEM, **P**olymer **M**embrane **E**lectrode. The PEM electrolyzers are essentially PEM fuel cells, common to fuel cell automobiles, run in reverse. Like the PEM fuel cells, the PEM electrolyzers require a Pt group metal catalyst on the electrodes. By contrast, the alkaline electrolyzers use nickel coated electrodes and a potassium hydroxide based electrolyte. Each configuration has its advantages and disadvantages which are balanced such that neither has a lock on the market.

Alkaline electrolyzers do not require a platinum group metal as an electrode catalyst but they do have a corrosive liquid electrolyte. Also, they must operate at lower current densities compared to PEM electrolyzers which results in more equipment for

---

[10] http://norvellnelson.com/wp-content/uploads//2017/10/20171011-Hydrogen-Electrolyzers.pdf
[11] IEA/HIA Task 25

a given production level[12]. In the largest system, costs are <$$10^3$ /kW. The PEM electrolyzers require higher purity water on the input as water can leave as vapor (can't have water borne residues left behind). The solid electrolyte is not corrosive but the water solution must be acidic for the needed ionic conductivity requirement. PEM costs run between $$10^3$ and $$10^4$ per kW.

The hydrogen generation processes with electrolyzers can be perfect match to the intermittent nature of wind power as they are perfect followers. An electrolyzer can go from 5% to over 100% (they can be overdriven for a bit) capacity in a matter of seconds.

Energetics of Water Electrolyzers

Real life operating efficiencies for the 2 types of electrolyzers have been calculated using data from Hydrogenics, a major supplier of both types of electrolyzers. In the calculation, the HHV (higher heating value) for hydrogen was used in agreement with the US practice. In Europe the LHV value for hydrogen would be used, as this value is lower and occurs in the denominator, the calculated European efficiency would appear to be higher for the same process.

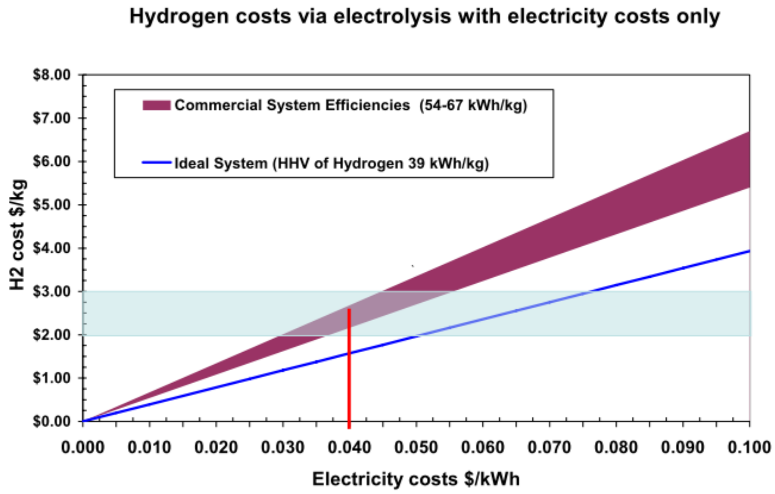
Hydrogenics PEM Electrolyzer				
Production Rate				
1	Nm3/hr =	0.08988	kg	Requires 4.9 kWh/Nm3
	Efficiency = (0.08988 kg x 39.3 kWh/kg / 4.9 kWh) x 100% = (3.53 kWh/ 4.9 kWh) x 100% =72%			
1	kWh =	3.6×10^6 J		3.6×10^3 kJ
Efficiency = 72% for H2 at 790 kPa max pressure (≈115 psi)				
Energy required to get to 35 MPa (5,000 psi) = 13 MJ/kg (multi-stage mechanical compression)				
Energy required to get to 70 MPa (10,000 psi) = 16 MJ/kg (multi-stage mechanical compression)				
Total energy for 1 kg H2 at 35 MPa = 54.5 kWh (196.3 MJ) electrolysis + 13 MJ for compression = 209.3 MJ				
Overall **Efficiency** = Energy of Product (H2 HHV)/ Energy to get there (at 35 MPa) = 141.6 MJ/ 209.3 MJ x 100% = **67.7%**				
Hydrogenics Alkaline Electrolyzer				
Largest System = 60 Nm3/hr = 5.39 kg/hr = 57.9 kWh/kg = 208.3 MJ/kg				
The alkaline electrolyzer is slightly less efficient than the PEM electrolyzer at **64%**				
	but quantity is 60x greater per unit time			

The key value to note when comparing electrolyzers is the energy required for the production of 1 Nm^3 (normal cubic meter) of hydrogen. That number will be around, but less than, 5 kWh per Nm^3 H_2.

NREL has provided reports on their Wind2H2 project which always includes the graph[13] below with the commentary that electricity cost is the overall controlling economic factor for producing hydrogen by electrolysis. **But what if the electricity**

[12] Electrochemical cells scale with electrode area, a square function.
[13] NREL/PR-560-40100 (2006), for one example of the same graph

has negative value to the grid operator? With the expanding deployment of wind power generation parks, the concept of negative real value for non-dispatchable wind power may be forthcoming. The most recent DOE target for the cost of hydrogen is on the order of $4-6 per kg H2. To give some perspective to this cost level, it should be noted that 1 kg of hydrogen has about the same energy content as a gallon of gasoline. The actual value is 0.997kg hydrogen equals one gge (gallon gasoline equivalent).



A more complete report on the capital costs of electrolyzers of differing capacities was written by G. Saur at NREL[14]. No case studied, however, covered use of the gas grid for hydrogen storage.

USE OF THE ELECTROLYTIC HYDROGEN

To be useful, some type of beneficial process(es) need to be available to use the electrolytic hydrogen, either directly or from some type of storage. As described in Reference 9, several pathways for utilization of hydrogen were considered under the various programs which were proposed. The programs can be divided into three categories: electricity to gas, with or without conversion to synthetic natural gas (SNG); electricity to gas then back to electricity; and, electricity to gas then back to electricity and heat (cogen). Each pathway had different process with their associated efficiencies. These paths are summarized in the following Table.

Potential Pathways for Use of Electrolytic Hydrogen from Renewable Energy Sources

Fuel	Efficiency	Pathway: Electricity ---> Gas
Hydrogen	54 - 72%	200 bar compression
Methane (SNG)	49 - 64%	
Hydrogen	57 - 73%	80 bar compression (Natural gas pipeline)
Methane (SNG)	50 - 64%	
Hydrogen	64 - 77%	without compression
Methane (SNG)	51 - 65%	
Fuel	**Efficiency**	**Pathway: Electricity ---> Gas ---> Electricity**
Hydrogen	34 - 44%	80 bar compression up to 60% back to electricity
Methane (SNG)	30 - 38%	
Fuel	**Efficiency**	**Pathway: Electricity ---> Gas ---> Electricity & Heat (cogen)**
Hydrogen	48 - 62%	80 bar compression & electricity/heat 40 - 45%
Methane (SNG)	43 - 54%	

[14] NREL/TP-550-44103 (2008)

From this Table, it can be seen that none of the considered processes are not, overall, highly efficient processes for storage and recovery of the renewable energy which had been converted to electrolytic hydrogen. They all suffer unfavorably when compared to batteries which have round trip efficiencies greater than 90%. Likewise, for pumped storage which may have round trip efficiencies above 80%.

There have been proposals for storage of the excess wind energy produced in Germany to be stored using pumped storage locations in Norway with undersea cables connecting the two countries. This approach has not been definitely established yet and will also not be considered here.

Examples of Utilization of Electrolytic Hydrogen from Renewable Energy

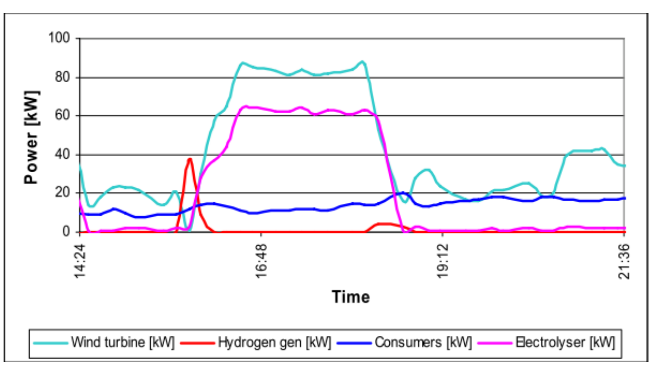
Two examples of the approaches presented in the above Table will be covered in more detail to illustrate the actual complexities involved in their embodiments: the direct use of the electrolytic hydrogen without storage of the gaseous hydrogen, and, storage of the electrolytic hydrogen in the natural gas grid for later recovery and use.

Norsk Hydro in Utsira, Norway

Norsk Hydro initiated a demonstration wind-to-hydrogen project which was designed to supply, as much as possible, all of the energy needs of Utsira, Norway. Utsira is a small island community of 240 people off the north coast of Norway. The project was deployed and integrated using the following equipment:

Key Components	Key data	Manufacturer
Wind turbine	600 kW	Enercon
Battery	35 kWh	Enercon
Flywheel	5 kWh, 200kW$_{max}$	Enercon
Synchronous Machine	100 kVA	Enercon
Electrolyser	10 Nm^3/h, 48 kW	Hydro Electrolyser
Compressor	11 Nm^3/h, 5.5 kW	Andreas Hofer
Hydrogen storage unit	12 m^3 @ 200 bar = 2400 Nm^3	Martin Larsson
Hydrogen genset	55 kW	Continental
Fuel cell	10 kW	IRD

A sampling of a typical operating power scheme involving the wind turbine, the hydrogen genset, the electrolyzer and the consumer draw-down is shown below. The project demonstrated the viability of the concept and the consumers were able to be off-grid over 80+% of the time. The average wind speed on the island was given at 10 m/s (22 mph).



Hydrogen Storage on the Gas Grid: The E.ON Project

E.ON has developed a project for Falkenhagen in northeast Germany which is planned to use electricity from “intermittent renewable sources”, aka wind, to generate about 360 Nm3/hr of hydrogen using water electrolysis. E.ON indicated that they would be using Hydrogenics electrolyzers. As Hydrogenics’ largest alkaline electrolyzer is rated at 60 Nm3/hr, it appears that they will need 6 of them.

The interesting aspect of this project is that E.ON plans to store the hydrogen on the gas grid. This approach is inventive and would use an infrastructure that is already in place. (The capacity of the German gas grid is large enough to store the hydrogen from the world’s entire current renewable electricity output.) The proposed plan would limit the store volume for the hydrogen to around 5% of the gas grid volume with a ceiling around 15%, for the project.

The use of the gas grid for storage eliminates costs due to dedicated tanks, leaving only the compressor and associated plumbing for post electrolysis handling of the hydrogen. Given this mixture in the pipeline, how does one recover the energy from this resource? Are there any issues which affect its use versus pure methane? Just how different are the properties of a mixture of 10% hydrogen in 90% methane from a 100% methane gas?

Properties of 10% Hydrogen 90% Natural Gas Mixture: The Gas Law Complication

We were all introduced to the Ideal Gas Law in freshman chemistry or beginning physical chemistry where is was presented as something like this equation:

$$\mathbf{PV = nRT}$$

Here P, V & T are the state variables of pressure, volume and temperature, n = number of moles of the gas and R = universal gas constant.

If we set P and T to the standard state values of P = 1 atm and T = 273K and solve for V with n = 1 mole of gas we find for methane V = 22.7 liters. Likewise, for hydrogen, we find that V = 22.7 liters. The (startling?) conclusion is that, to a first approximation, all gas molecules have the same volume! Think about that and its consequences.

While hydrogen and methane molecules have about the same molar volumes, they do not have the same volumetric energy content. For methane we have 35.22 MJ/m3 (LHV) and for hydrogen we find a value of 10.05 MJ/m3 (LHV)[15]. Thus, a mixture of 90% methane and 10% hydrogen would have an LHV heating value of 32.7 MJ/m3 or 7% <u>less</u> than pure methane.

The 7% reduction in the volumetric heat content afforded by a 90% methane 10% hydrogen mixture is but one example on the allowable mixture spectrum of the 2 gases. The mixture’s heating value could be anywhere along the composition spectrum.

---

[15] Useful compilation by Iain Staffell, University of Birmingham, 2011 (staffell@gmail.com).

The question is…can the thermal processes using this gas mixture tolerate such an uncertainty in the incoming gas composition? The answer is a kind of “maybe”. A presentation at the 2014 ICEPAG meeting looked at the use of gas mixtures of methane and hydrogen as a feed for a high temperature SOFC[16]. The mixtures were not always successful in maintaining operation, particularly noticeable with the mixture containing about 10% hydrogen. SOFCs operate at elevated temperatures, >600C, and some methane/hydrogen mixtures did not have a sufficient volumetric heat content required to maintain operation when fed into the SOFC as a single fuel stream at a constant (but metered) flow rate.

With gas turbines, the situation is a bit more complex but doable with some added instrumentation and a source of gaseous C2+ hydrocarbons, which can be added to the incoming gas mixture to adjust the volumetric heat content to meet the required operating values[17]. Gas turbine generators are of sufficient cost that some added expenditures for the stabilization of the composition (volumetric heat content) of the incoming gaseous feedstock is quite justifiable.

The same arguments cannot be made for thermal processing systems such as hot water heaters. Fuel gas compositions here are required to be within certain compositions to control emissions of incidental combustion products such as NOx species.

While there may be a potential application for using the gas grid to store hydrogen generated using excess renewable energy, there appears to be some issues remaining for extraction of the energy contained in the resulting gas mixtures.

Potential Equipment Technical Issues

The preceding section illustrated just a few issues with the storage of hydrogen in the gas grid and the subsequent use of the hydrogen – natural gas mixtures to recover the energy values. While the ideal gas law would show that hydrogen and methane have the same molar volumes, they differ in some important physical properties. For example, hydrogen has an extremely low viscosity (hard to contain leaks), an inverse Joule-Thompson coefficient (hydrogen heats up when expanded through an orifice), and, a very high heat transfer coefficient.

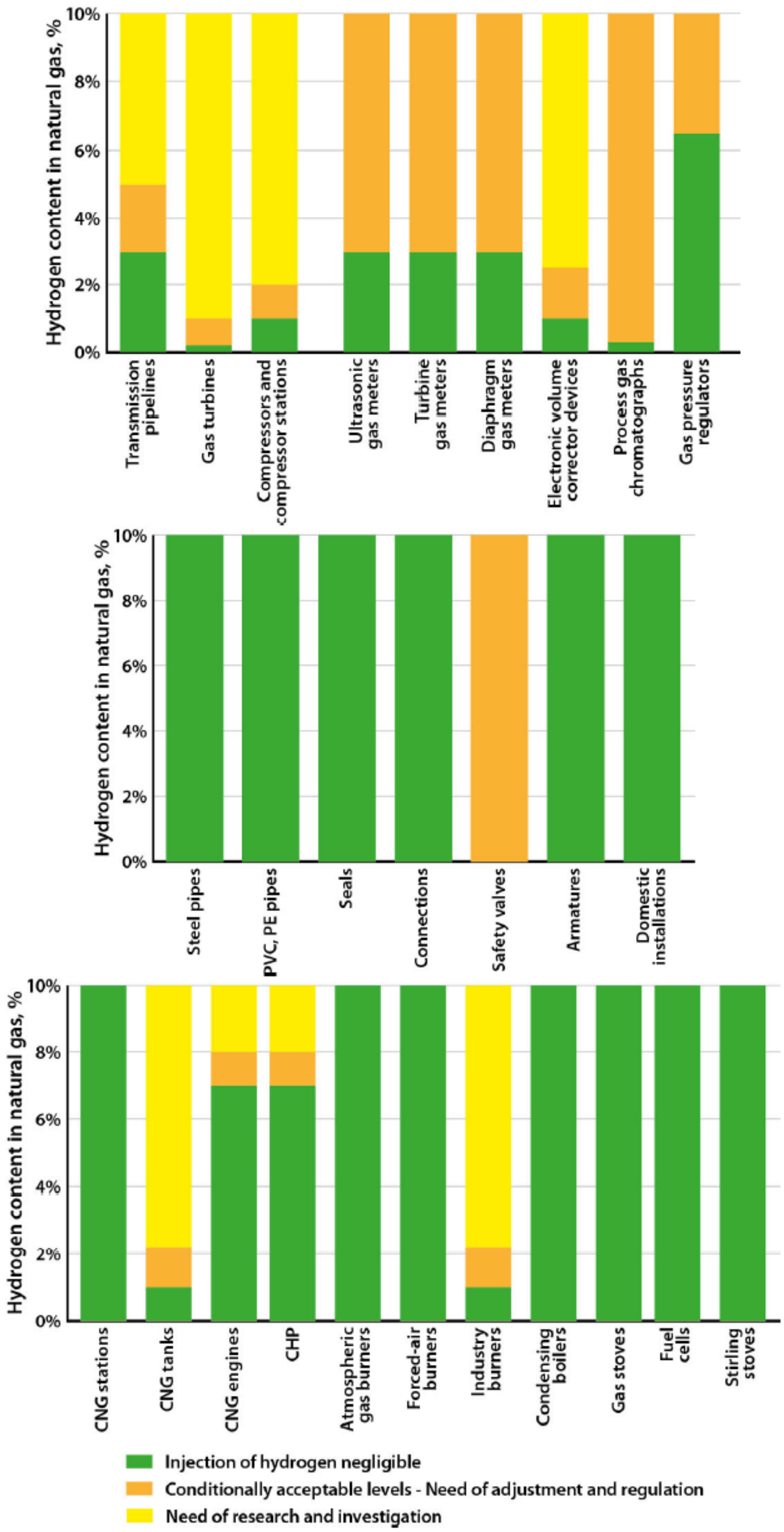
Given the difference in properties between hydrogen and methane, one might expect some significant property differences between methane and its mixtures with hydrogen which may show up in infrastructure issues relating to the gas mixtures. In fact, there are and they have been cataloged in a paper written by Blacharski, Kogut and Surlej which appeared earlier as Reference 4. The authors presented a critical review of the many issues surrounding the storage and use of hydrogen in the gas grid.

A question not addressed in the initial rush to exploit the “storage in the gas grid” concept, was that very little consideration was expressed concerning the compatibility

[16] SOFC = solid oxide fuel cell

[17] THE IMPACT OF NATURAL GAS COMPOSITION VARIATIONS ON THE OPERATION OF GAS TURBINES FOR POWER GENERATION, The Future of Gas Turbine Technology, 6th International Conference, 17-18 October 2012, Brussels, Belgium

of the hydrogen – natural gas mixtures with the existing gas grid components. The Polish authors did a great service in noting where these gas mixtures were compatible with the existing infrastructure and where additional study was required to verify this compatibility as given in the figure, below.



As indicated in the figure, there are quite a few areas where equipment compatibility with the hydrogen – methane mixtures needs to be established and verified. Thus, the availability of the gas grid for hydrogen storage requires additional engineering studies for certification of this new us of the gas grid.

Summary

It does appear that the gas grid could be a definite possible reservoir for hydrogen storage but not ready in the near term. A lot of details have to be worked out before this action gets a full go, as is always the case with a large-scale deployment of a proposed new technical solution in energy technology. The full consequences of mixing hydrogen into the gas grid needs quite a bit more study as more of these issues arise.

Remember that no one technical advancement occurs in a vacuum, that is, every technology is advancing at its own pace irrespective of the others. In particular, battery storage technologies are reporting continuing advances in both storage capabilities and cost structures on, an almost, daily basis. Battery storage deployment, in comparison to power-to-gas does not require any reconfiguration of its (the electric) grid. For example, consider the rapid deployment of a Tesla sourced battery storage facility in Australia.

In any case, it will be the overall economics of the entire process(es) that will have final say on which storage technologies will be deployed and used, as always.

Norvell Nelson
November 8, 2018
Lakewood CO