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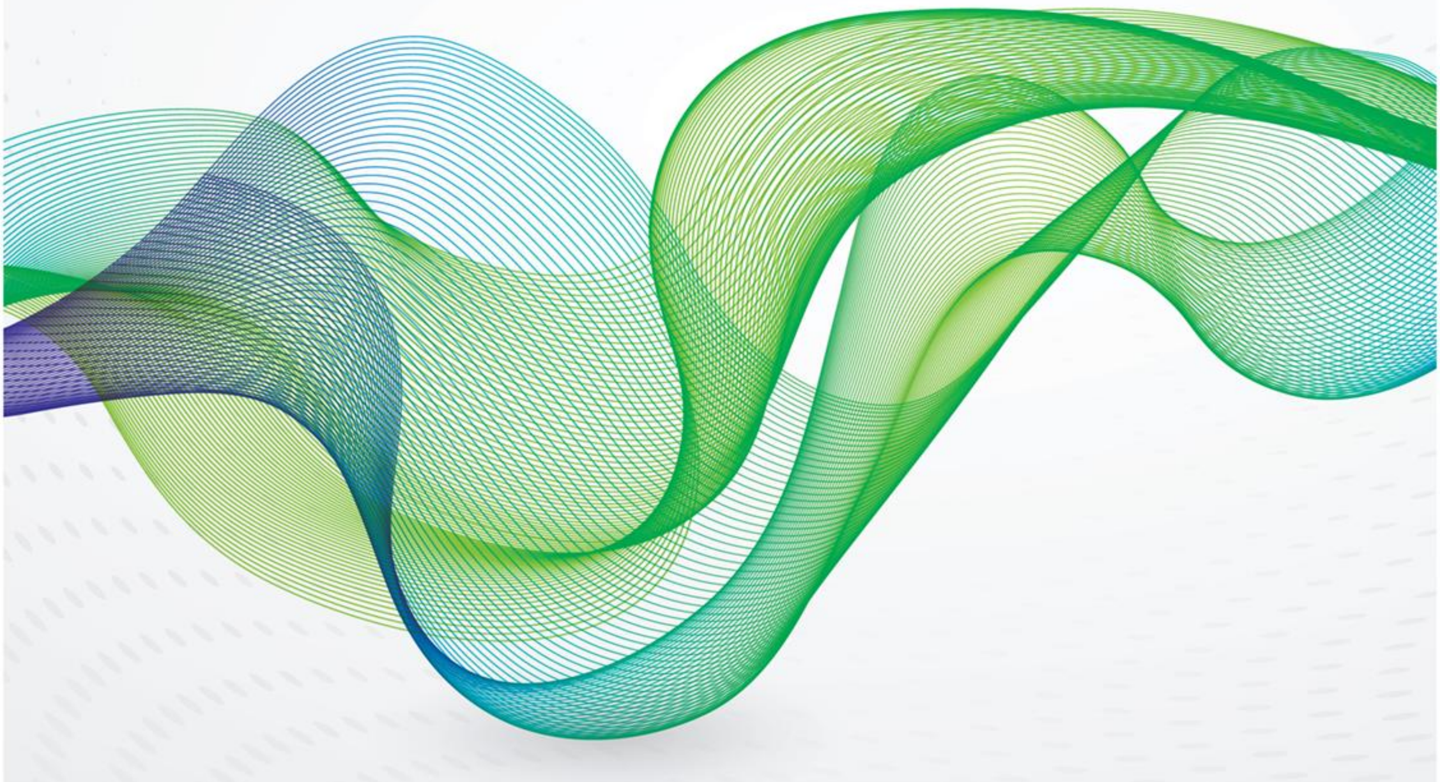

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Abstract

This paper analyses whether ammonia can be viewed as an economically efficient and technologically suitable solution that can address the challenge of large-scale, long-duration, transportable energy storage in the decarbonized energy systems of the future. It compares all types of currently available energy storage techniques and shows that ammonia and hydrogen are the two most promising solutions that, apart from serving the objective of long-term storage in a low-carbon economy, could also be generated through a carbon-free process. The paper argues that ammonia, as an energy vector of hydrogen, is preferable to pure hydrogen from economic, environmental, and technological perspectives. It then analyses the available ammonia generation techniques, identifying conditions under which zero-carbon ammonia makes sense economically, and briefly highlights policy prerequisites for such production to be attractive for investors. Given the current state of the industry, large-scale deployment of green ammonia is unlikely to happen without policy supports such as adequate carbon taxes and/or alternative incentives. In the absence of such policies, green ammonia is only likely to make small-scale advances in the energy system, in areas with extremely low-cost renewable energy production or a significant surplus of generated energy.

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1. Introduction

The main function of energy storage is to transfer energy across time, but when the stored energy is transportable, it can also transfer energy across space. These two functions are critical to address variations in energy supply and demand and to deliver remote energy resources to end users.

Seasonal fluctuations in energy demand are significant in most countries of the world, owing primarily to climatic and geographic conditions which cause temperature variability during the year (Omura, 2012, p.499). Winter heating in colder countries, and summer cooling in warmer ones, constitute substantial parts of the national energy demand of such countries. For instance, heating buildings during cold months accounts for around 25 per cent of the UK's energy demand (Energy Research Partnership, 2016). Normally, such a seasonal demand peak is addressed through energy storage (Paksoy, 2007), which in many countries appears to be through a form of fossil fuel such as natural gas. In particular, natural gas provides significant flexibility as it is produced, bought, and stored underground during the pre-heating season, so that it does not have to be purchased during the winter, when demand for it is high (British Geological Survey, 2019).

Although currently the heating sector (and the cooling sector based on fossil fuel electricity) is mainly dominated by fossil fuels across the globe, in a future low-carbon scenario, fossil fuels will have to be replaced with green electricity or other zero-carbon alternatives if there is no economic way of capturing CO_2 emissions at the point of combustion. However, renewable energy generation cannot be substantially increased, on demand, to meet peak demand. This means – in the absence of long-term energy storage – that in order to cover seasonal winter heating, or summer cooling, solely by renewables, there is a need for significant excess capacity in the electricity system, which makes it very inefficient.

The need for long-term large-scale energy storage is also motivated by the plausibility of unpredictable disturbances that could have significant adverse effects on energy supplies. This is specifically important in renewables-dominated energy systems, which are characterized by high levels of variability and uncertainty. In addition, in many places, peak demand for heating and/or cooling does not coincide with peak renewable generation. For instance, in temperate zones, winter often coincides with 'dark calm' ('Dunkelflaute') periods with 'challenging weather conditions' – such as snow cover, or high pressure that minimizes the potential for solar or wind generation (Fuchs et al., 2012, p. 6). In a similar manner, in the Gulf Cooperation Council Countries (GCC), where demand peaks during summer months, solar PV generation drops because of the adverse effects of ambient temperature and sandstorms on solar panel outputs (Alshawaf, Poudineh, and Alhajeri, 2020). There are also studies arguing that climate change itself might increase the likelihood of long periods of low wind generation, leading to increased seasonal variability or intensified fluctuations of wind power generation from year to year (Weber et al. 2018, p. 1; Giannakopoulos and Psiloglou, 2006, p. 97). These all mean that, in a renewable energy dominated power system, storing large volumes of energy for a long period of time is likely to be crucial in addressing the challenge of meeting peak demand.

In addition to the time aspect, there is also a spatial dimension to energy storage. The cheapest and/or the cleanest energy resources are not necessarily close to demand centres, and connecting low-carbon energy resources to users may not always be easy or cheap. In the case of electricity, for example, the costs of electricity transmission infrastructure can be an impediment to the utilization of some wind and solar resources in remote areas (Mazzanti and Marzinotto, 2013). Specifically, the construction of power interconnections over extreme distances is very costly and likely to face technical limitations due to geographical complexity. For instance, despite having officially announced the idea of constructing a 1,500 km subsea High Voltage Direct Current (HVDC) interconnector between Iceland and Great Britain in 2012, Iceland and Britain have already shifted the commencement date several times, due to the considerable degree of uncertainty in the economic efficiency of the project (Bloomberg, 2013). As a result, the IceLink project – the world's longest power link of its kind – is still at its feasibility and commitment stage, with the ‘new’ launch date planned for the mid-2020s (Atlantic SuperConnection, 2019).

Delivering low-carbon electricity over very long distances and in complex environments by conventional means might not always be the most efficient approach. Thus, finding the missing link that could connect low-cost renewable energy resources with final users is just as important to the overall success of decarbonization as generating green electricity and electrifying energy consumption. Generation and consumption could potentially be connected in space by means of storing large volumes of energy in a transportable form.

While technologies allowing for the large-scale preservation of energy are multiple, the future of energy storage is more often associated with either electrochemical storage (for example, batteries) or chemical storage (such as hydrogen or ammonia). Currently, despite the gradually decreasing production cost of electrochemical storage, the cost of storing energy per kWh for chemical storages such as hydrogen (H_2) is significantly lower in comparison with most long-lasting batteries. On the other hand, despite being often viewed as an option to address the challenge of long-term large-scale energy storage, pure H_2 poses a number of challenges associated with the way it is kept and delivered. This has resulted in a growing interest in exploring ammonia (NH_3) as a more advantageous storage option.

Although ammonia has the potential to be used as a fuel in a direct combustion process or in ammonia-fuelled fuel cells for land and marine transport or power generation purposes, its highest product value can be achieved when used as a hydrogen carrier. Ammonia could thus be appropriate for most power and energy systems. In countries with excess power from, primarily, non-intermittent low-carbon energy sources, such as nuclear, ammonia can assist in organizing the stable export of energy to previously unexplored markets. On the other hand, in places with intermittent energy resources, such as wind and solar, ammonia can help to balance the energy system while sporadically augmenting the country’s energy exports if there is excess generation. In hydro systems, ammonia could help in dealing with the seasonal variability of water flow. In places with load centres scattered over a vast geographical territory, ammonia could offer new means to deliver sources of green energy to remote locations and regions.

This paper analyses the role of ammonia in energy systems and briefly discusses the conditions under which it provides an efficient decarbonized energy storage solution to preserve large volumes of energy, for a long period of time and in a transportable form. The outline of this paper is as follows. The next section compares all the currently available storage solutions that allow for the prolonged preservation of large volumes of energy; it then highlights ammonia’s unique features, its specific advantages and disadvantages. Section 3 discusses some uses of ammonia and methods used in its production. Key challenges of ammonia production are discussed in Section 4. Section 5 analyses the cost drivers of ammonia production. Finally, section 6 provides the concluding remarks.

2. Energy storage technologies: candidates for long-term large-scale storage

Fundamentally, there are four different types of energy storage technologies: electrical, electrochemical, mechanical, and chemical (see Table 1[1]). In this section we discuss each of these storage types and their specifications, with respect to their ability to provide large-scale long-duration storage service.

2.1. Electrical

Electrical energy storage is primarily represented by ***superconductors*** and ***supercapacitors*** (Fuchs et al., 2012). The *superconductor* is normally characterized by very high efficiency, but its relatively low storage capacity, energy density, and intensive daily energy loss (self-discharge) are likely to limit its large-scale integration in the energy system. Additionally, and potentially most importantly for the

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[1] Although direct storage of heat is also possible, the paper does not discuss that; instead it focuses on the main methods of energy preservation with application in the electricity sector as the driver towards a more sustainable future.

standard size of most applications, its cost would be prohibitive (Bañares-Alcántara et al., 2015, p. 122). On the other hand, with similar high efficiency indicators, but significantly lower energy installation costs, *supercapacitors* are most suitable for short-term small-scale storage (ibid). Thus, at its current development stage, electrical storage is not suitable for long-term large-scale energy storage.

2.2. Electrochemical

Electrochemical energy storage is represented by four main types of batteries (***redox flow***, ***lead-acid***, ***lithium-ion***, and ***high temperature***). *Lithium-ion* technology has the highest round-trip efficiency and storage capacity among batteries and could dominate the energy storage future as its continuing decline in price, along with improved performance, will likely open new markets (Renewable Energy World, 2019). There are also arguments in favour of vanadium *redox flow* batteries, due to the fact that there is much more vanadium in the earth's crust than lithium, which makes this technology more scalable (Energy Post, 2019). The other two technologies (*lead-acid* and *high temperature*), however, are not suitable for large-scale use as their energy capacity is several times smaller in comparison with lithium-ion and redox flow (Fuchs et al., 2012). Although lithium-ion and redox flow are potential candidates for global utility-scale storage capacity, none of the technologies has progressed sufficiently to increase its energy storage capacity to a level comparable with that of fossil fuels, in order to make the transportation of batteries over long distances economically feasible. On top of that, as can be seen from Table 1, these technologies are among the most expensive on the cost curve. Thus, electrochemical energy storage will have to be further advanced to address the long-term large-scale energy storage dilemma.

2.3. Mechanical

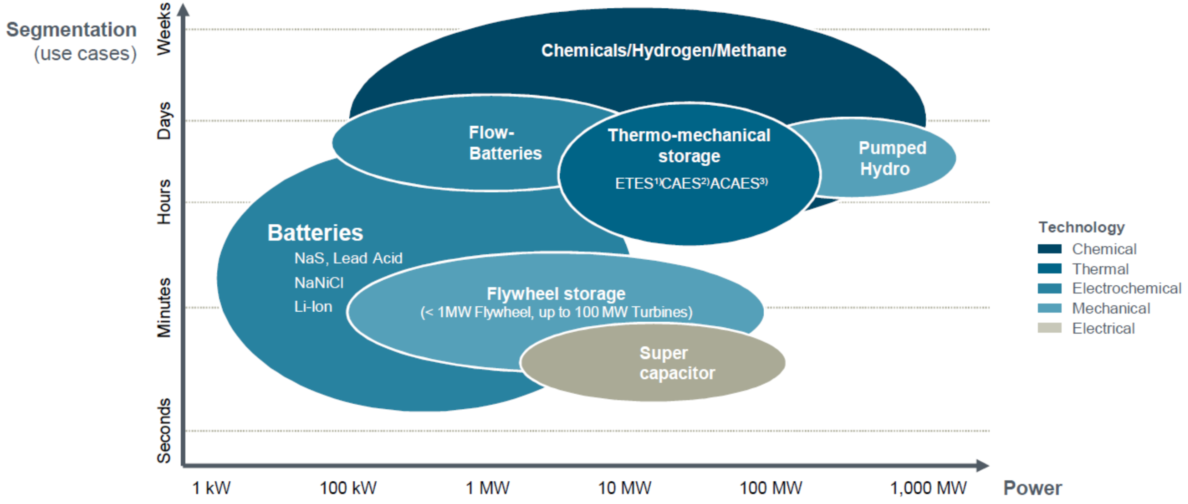
Mechanical energy storage technologies (such as ***flywheel***, ***compressed air***, and ***pumped hydro***), while each performing quite different roles, have greater industrial applicability in a net-zero carbon scenario, due to their lower installation costs when compared to supercapacitors and superconductors. Despite their high energy density (80–200 Wh/l) and round-trip efficiency (80–95 per cent), *flywheels* are approximately similar to electrical types of energy storage in terms of low capacity (about 0.0001GWh) and extremely high daily energy loss (self-discharge of 5–15 per cent/hour) (Fuchs et al., 2012 and Bañares-Alcántara et al., 2015). Therefore, although currently assisting with fast-response ancillary services, flywheels do not seem to be suitable candidates for storing energy in large quantities and for a long time. On the other hand, though rarely used despite its low cost and self-discharge rate, *compressed air* complements *pumped hydro* (currently described as one of the most prevalent method of grid-scale energy storage) (Bañares-Alcántara et al., 2015, pp. 120). Indeed, apart from offering ancillary services requiring short-term electricity storage, both technologies can also serve for long-term large-scale energy preservation, as they can cater for periodic and seasonal storage as well as emergency backup. This is not surprising as, notwithstanding their relatively low energy density, compressed air and pumped hydro can provide significant storage capacity (ibid). However, the downside is that neither of these storage technologies is transportable. In this sense, even if they could potentially solve the problem of decarbonizing on-land grids, pumped hydro and compressed air will not be able to deliver energy over distances. That is why mechanical applications do not seem to be suitable for providing the ultimate solution to the challenge of large-scale, long-term, and transportable energy storage.

2.4. Chemical

Chemical energy storage is viewed as an important candidate for a large-scale, long-duration, and transportable form of energy preservation as, apart from sources such as ***natural gas***, energy can be stored in the form of ***hydrogen*** and ***ammonia*** (NH_3). (Bañares-Alcántara et al., 2015). As natural gas does not fully align with environmental objectives in the absence of carbon capture, utilization, and storage (CCUS), the solution of the long-term large-scale energy storage dilemma seems to belong to either hydrogen or ammonia. Hydrogen and ammonia have roughly the same energy intensity and costs (Fuchs et al., 2012). However, as 'liquid ammonia has over 50 per cent more volumetric energy than liquid hydrogen; more than twice the volumetric energy of hydrogen gas at 700 bar', it seems to be more economically advantageous (US Department of Energy, 2010). In addition, in comparison to hydrogen, ammonia is easier and less dangerous to handle. Specifically, its vapor pressure is much lower (‘10 bar at 25^{o}C’), which to a great extent simplifies the design of storage tanks for transportation purposes (Rivard, Trudeau, and Zaghib, 2019, p. 11). Therefore (if it is generated through a carbon-free process) ammonia can be used for storing large amounts of energy for a long time in a transportable form because of its specific physical features; this is essential for achieving a low-carbon future.

Figure 1 provides a comparison of different storage solutions in terms of their capacity and duration of preserving energy.

Figure 1: A comparison of different storage options in terms of capacity and duration



1) Electro-Thermal Energy Storage 2) Compressed Air Energy Storage 3) Adiabatic Compressed Air Energy Storage

Source: Siemens (2017)

Overall, preserving energy by chemical processes offers a unique set of services and values that cannot be fully replicated by other types of energy preservation technologies. Indeed, in the words of Siemens, a company working on the extended integration of renewables and energy storage, ‘for big-capacity, long-duration storage, chemical fuels are hard to beat’ (Green Tech Media, 2018). Among chemical storage solutions, ammonia takes a special place due to its unique features.

First, ammonia is relatively easy to handle. Of all the chemical storage options presented in Table 1, ammonia produced by means of electrolytic hydrogen generation stands out as a ‘green’ solution that is easier to handle than hydrogen. Specifically, being less flammable than hydrogen, ammonia is a safer fuel to deal with in this respect (US Department of Energy, 2006). In addition, with its boiling point of –33.36 ^{o}C, NH_3 is easily liquefied and requires less energy for storage and transportation than H_2, whose boiling point is –252.9 ^{o}C (IIAR, 2008). Finally, ‘undeniably offensive at higher strengths, its characteristic smell provides an invaluable early warning of potential lethal emission’ – a feature not found in pure hydrogen (Elucidare, 2008).

Second, it is rapidly deployable. Being one of the most important commodity chemicals in the world, NH_3 also represents one of the most widely generated chemical products (Angeles et al., 2017, p. 271). That is why its ‘handling and shipping infrastructure including regulations for transportation are already in place’ (Valera-Medina et al., 2018, p.69). Traditionally, ammonia is transported and contained in tanks under a modest pressure, which means it could be rapidly deployed to the part of the energy system where it is needed (Valera-Medina et al., 2018, p.69). The distribution mechanism of ammonia represents a great variety of transport modes and means, including pipelines, railroads, barges, ships, road trailers, and storage depots (Elucidare, 2008). Thus, scaling up NH_3 production and distribution does not need extensive investment in infrastructure development.

Table 1: Available energy storage technologies

Technologies			Current max. storage capacity (GWh)	Energy density (Wh/l)	Maximum storage duration	Round trip efficiency (%)	Self-discharge (%/day)	Approximate costs[2]		Services to the power system	Advantages	Drawbacks
Type	Appliances							Power installation (USD/kW)	Energy installation (USD/kWh)			
Electrical	Supercapacitor		*approx. 0.0001*	2–10	Seconds–minutes/ hours–days	*90–94*	*<=12.5*	*11-22*	*11,000-22,000*	• *Frequency control* • *Voltage control* • *Peak Shaving*	• *Easy to store* • *Easy to transport* • *High efficiency*	• *Low energy density* • *Low storage capacity* • *Short storage time* • *High self-discharge rate* • *High costs per installed density*
	Superconducting coil		<=0.1	0.5–10		80–90	10–15	320–650	1,000–72,000			
Electrochemical (batteries)	Flow	V-redox	<=0.8	20–70	Hours–days	*60–70*	*0.15–1*	*1,100–1,650*	*315–1050*	• *Frequency control* • *Emergency backup* • *(Potentially) periodic and seasonal storage*	• *Easy to store* • *Potentially transportable* • *Medium efficiency*	• *High costs* • *Medium storage time* • *Relatively high self-discharge*
		Zn-Br					*8–33.6*		*525–1650*			
	Lead-acid	Flooded	0.04	50–100		70–82	0.09–0.4	165–220	105–473	• *Frequency control* • *Peak shaving* • *Load levelling* • *Emergency backup*	• *Low self-discharge* • *Low power installation costs* • *Transportable*	• *High costs* • *Medium storage time* • *Leak-prone*
		Valve regulated				70–80						
	Li-ion	Li-Fe Phosphate	<=0.5 (for stationary module systems)	200–350		<=92	0.09–0.36		200–840	• *Frequency control* • *Voltage control* • *Peak shaving* • *Load levelling* • *(Potentially) seasonal storage*	• *High efficiency* • *Medium energy density* • *Long lifetime* • *Transportable*	• *High cost* • *Complex battery management system needed (single cell monitoring)*
		Li-Titanate				<=96			473–1260			
		Ni-Co-Al				<=95			200–840			
		Ni-Mg-Co										

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[2] Costs in currencies other than USD were converted to USD according to the rate on Bloomberg (2019a) as of 12 November 2019 and hence are approximate.

	High tempe-rature	Na-Ni-Cl	<=0.034	150–250		*<=84*	*0.05–15*		*315–488*	• *Frequency control* • *Peak shaving* • *Load levelling*	• *High efficiency* • *Medium energy density* • *Transportable*	• *High cost* • *Potential hazard due to high temperatures* • *Relatively low storage capacity*
		Na-S				*<=80*	*0.05–1*		*263–735*			
Mechanical	Flywheel		*0.0001*	80–200	*Seconds–Minutes*	*80–95*	120–360	*330*	*~1100*	• Frequency control • Voltage control • Peak shaving	• *Fast charge* • *Low maintenance costs*	• *Low storage capacity* • *Short storage time* • *High self-discharge* • *Safety threats (cracks)*
	Compressed air		<=1	3–6	Hours–days/ weeks–months	*60–70*	*0.5–1*	*770–1100*	*45–90*	• *Frequency control* • *Voltage control* • *Peak shaving* • *Load levelling* • *Standing reserve* • *Black start* • *Emergency backup* • *Periodic and seasonal storage*	• *Low self-discharge* • *Medium round-trip efficiency* • *Long storage time*	• *Low energy density* • *Storage capacity constrained by geography* • *Limited transportability* • *Only large-scale units connected to grid are economically feasible*
	Pumped hydro		Currently, ~3, potentially <=14	*0.27–1.5*		75–82	0.005–0.02	550–1100	5.50–22			
Chemical	Natural gas		~1260, (underground caverns)	10.1 (natural gas) 6,200 (LNG)	Weeks–Months	*30–35*	0.003–0.03	1100–2200	~0.09	• *Emergency backup* • *Periodic and seasonal storage*	• *Transportable* • *Large storage capacity* • *Long storage time* • *Low self-discharge* • *Low energy installation costs* • *High energy density* • *Extremely low self-discharge*	• *High costs of electrolysers* • *Low round-trip efficiency* • *High energy consumption* • *High power installation costs*
	Hydrogen		0.13 (tanks), ~124-167 (underground caverns)	2,400 (liquid)		*30–60*		*1650–2200*	0.35–17			
	Ammonia	Steam reforming	0.25 (cooling tanks) ~300 (underground caverns)	3,194–4,325 (liquid)		*20–25*		~1,100	>=0.11			
		Electrolysis				<= 40–72		*1210–2300*	>=0.24			

Source: authors compiled from AEA Group (2010), Nomura et al. (2010), Brown (2011), Energy Research Partnership (2011), Fuchs et al. (2012), GENI (2012),Patil, Laumas, and Vrijenhoef (2014), Bañares-Alcántara et al. (2015), Bunger at al. (2016), EIA (2017), IEEE (2017), IRENA (2017), Wang, Mitsos, and Marquardt (2017), BloombergNEF (2018), Gur (2018), PG&E (2018), US Department of Energy (2018), Horseman et al. (2019), IEA (2019b)

Third, NH_3 bonds together one nitrogen atom and three hydrogen atoms, which makes ammonia a ‘better molecule at packing together with itself’ in comparison to hydrogen (H_2) (Kraemer, 2018, p. 1). Thus, there is a greater mass of hydrogen in a litre of liquid ammonia than in a litre of liquid hydrogen (ibid). That is why liquid ammonia seems to be a more efficient hydrogen carrier than liquid hydrogen itself, as more energy can be delivered within the same volume of storage vessel.

Finally, it potentially produces no carbon emissions. Ammonia is unique as a fuel because it does not contain carbon, which means its combustion does not produce CO_2 emissions. It can also be produced carbon-free. Although the traditional process of producing ammonia – steam reforming – normally utilizes either natural gas or coal as the main fuel, if ammonia is produced from green hydrogen there would be no CO_2 emission. Here, however, as in other similar cases, in order to gain wider use, the zero-carbon process of ammonia production needs to be proven economically efficient.

Ammonia also has a number of disadvantages. For instance, the direct burning of NH_3 is technically impeded by its low flammability and radiation intensity (Kobayashi et al., 2019). In particular, these characteristics hamper ammonia’s self-sustained burning and heat transfer in a combustion system, and thus turn it into a challenging fuel to rely on (Coelho, 2017). At the same time, even with a successful NH_3 incineration, ‘an additional challenge of NH_3/air combustion relates to the high fuel NOx emission’ (Kobayashi et al., 2019, p. 111). That is why, to abate NOx emissions, some more advanced technologies such as, for example, Selective Catalytic Reduction, are needed (Kim et al., 2020). This, however, will lead to additional cost. Therefore, with the currently available ammonia incineration technologies, this fuel is unlikely to represent a first-choice option for a combustion process.

Another disadvantage is that green ammonia production is not yet fully established. As of 2018, pilot plants for the production of green ammonia had just started operations in the UK and Japan, and new demonstration plants were announced in Australia, Denmark, Morocco, and the Netherlands (Ammonia Energy Association, 2018). As this generally implies the current limited scope of the popularization of unconventional ammonia production, NH_3 generation based on electrolysis is yet to be well-established.

Furthermore, despite being less flammable than hydrogen, it is a highly toxic chemical associated with ‘coma and convulsions’ at ‘a blood ammonium concentration of 200 µmol/L’ (UCL, 2018). This toxicity factor appears to be ‘one of the major impediments to deploy these technologies, as public perception is very formative’ (Valera-Medina et al., 2018, p.67). That is why, despite its highly identifiable odour making leakage identification easier, proper storage of NH_3 and prevention of its leakage should be viewed as a priority – not only by ammonia producers, but also by its storage operators, transporters, and end users, especially because of the substance’s tendency to concentrate near the ground and quickly dissolve in water (UCL, 2018). If any leak happens, this may not only create a precondition for the eutrophication[3] of bodies of water but also pose significant threats to public health (Kanmann and Johnsson, 2001).

The hazardous features of NH_3 place additional pressure on the actors dealing with the substance. For instance, companies organizing ammonia transportation and storage in tanks need to take measures to avoid the so-called ‘Ammonia Stress Corrosion Cracking’ – the ‘phenomena of cracks being formed in carbon steel in contact with ammonia’ (Fertilizers Europe, 2019). In addition, due to the tendency of an ammonia–air mixture to explode when exposed to high heat, preserving the right temperature is crucial (New York State Department of Health, 2004 and Fertilizers Europe, 2013). In this context, with a broader use of ammonia in the future and an increased number of actors involved in its handling, undertaking the required safety measures will not only presuppose additional indirect costs but also require a more comprehensive approach to safety training, public education, and policymaking.

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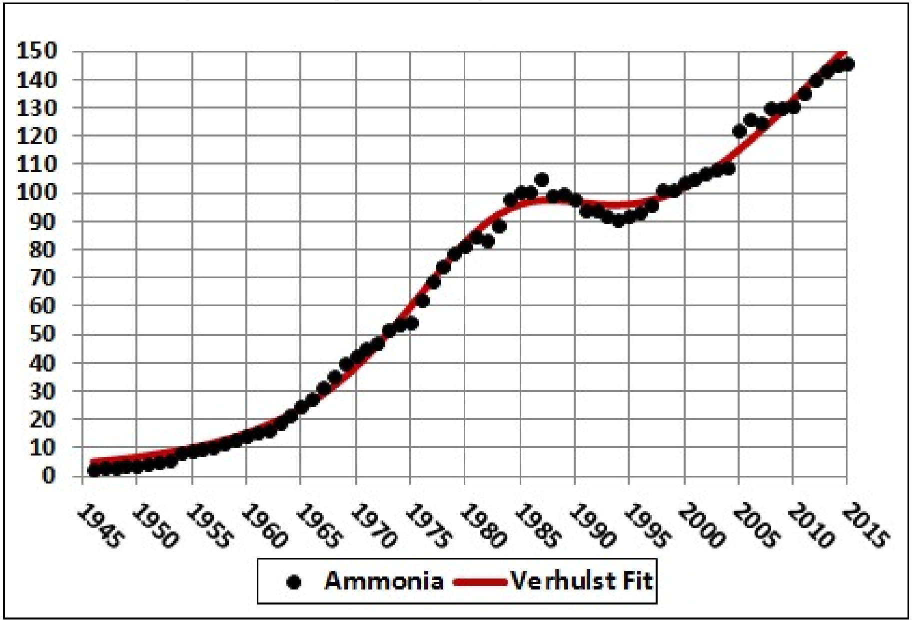
[3] Eutrophication is generally defined as ‘the nutrient enrichment of waters that stimulates an array of symptomatic changes, that can include increased phytoplankton and rooted aquatic plant (macrophyte) production, fisheries and water quality deterioration, and other undesirable changes that interfere with water uses’ (Holland and Turekian, 2005, p. 312).

3. Ammonia production and application

According to the US Geological Survey (2017), the world's ammonia production has experienced a constant rise over the last two decades (see Figure 2).

Figure 2: World ammonia production (106 tonnes)



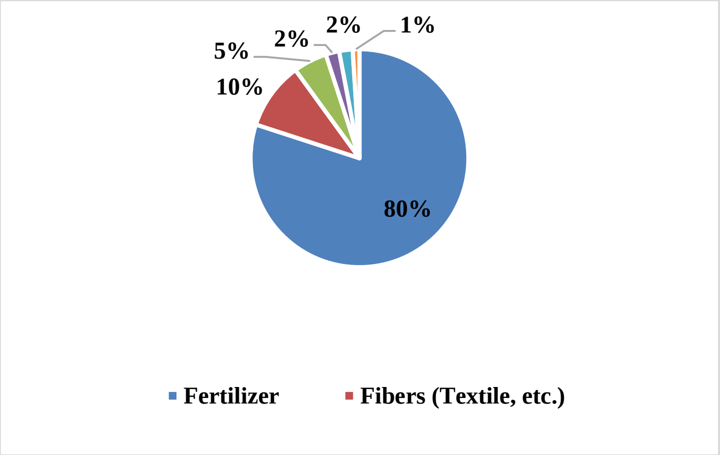
Source: US Geological Survey (2017)

3.1. Uses of ammonia

Apart from being produced in many countries for domestic use, NH_3 also represents a very well exported commodity. Such popularity is not surprising, as the global production and trade of ammonia is highly driven by the fertilizer industry, given that it is an important nitrogen-rich ingredient (Ash and Scarbrough, 2019, p. 25). Indeed, roughly 80 per cent of globally generated ammonia is used for making fertilizer, and about 50 per cent of the world's food production relies on ammonia fertilizer (Boerner, 2019, p 1). In the context of the growing world's population and demand for agricultural products, the demand for fertilizers is also expected to rise. However, agriculture does not represent the only industry where NH_3 is applied.

Ammonia is also widely used in the chemical and other related industries as a precursor to nitrogen-containing substances (Godula-Jopek, Jehle, and Wellnitz, 2012, p. 182). For instance, oxidizing NH_3 in the generation of HNO_3 (nitric acid) enables the production of explosives, as NH_4NO_3 (ammonium nitrate) represents the key ammonia derivative used in this manufacturing process (Negovanovic et al., 2015). Additionally, the textile industry applies ammonia in softening cotton as well as in the production of synthetic fibres (such as nylon and rayon) (Lee et al., 2016). Similarly, owing to nitrate's antimicrobial characteristics, NH_3 is popularly used in generating antibacterial drugs (Shtyrlin et al., 2016). Therefore, most of the ammonia produced globally is utilized as an intermediary element in the manufacture of more complex commodities due to its unique chemical properties (Figure 3):

Figure 3: Global application of ammonia



Source: Adaptation from Holleman and Wiberg (2001), ASHRAE (2017), Dissanayake (2017), US Geological Survey (2017), Perinelli et al. (2019)

In contrast to its chemical properties, the advantages of ammonia's unique *physical features* do not seem to be fully realized, as most of the globally produced NH_3 stock is currently used in agriculture. Indeed, only around five per cent of all the generated NH_3 is applied in its pure form for non-agricultural purposes at the industrial scale, with about two per cent amalgamating all its minor applications (Figure 3). Additionally, approximately the same amount has been continuously used as a refrigerant in industrial refrigeration processes, given its superior thermodynamic properties and low cost (ASHRAE, 2017, p.1). This leaves *around 1 per cent or less* for the experimental and test engines and gas turbines where ammonia is applied as a fuel (Dissanayake, 2017). Therefore, currently, the application of ammonia in the energy sector is very insignificant.

Such a low level of penetration of ammonia into the energy sector could be viewed as an opportunity for further progress, especially as NH_3's physical qualities could offer significant room for energy-based applications. For instance, with a significant further improvement of ammonia combustion technologies, pure NH_3 can potentially serve as an alternative to fossil fuels in internal combustion engines and generators. Due to the absence of carbon in its chemical structure, the incineration of ammonia does not generate CO_2, CO, hydrocarbons, or soot, but only nitrogen and water (Lasocki, 2018, p.2[4]). Nevertheless, further technological improvement of the existing combustion engines is needed to increase their efficiency, to deal with ammonia's narrower flammability range, higher ignition temperature, and lower combustion efficiency when compared to common hydrocarbons (Kobayashi et al., 2019, pp. 112). More importantly, however, NH_3 combustion technologies need to be improved in order to enable a complete elimination or minimization of NOx emissions (caused in all forms of air combustion); these processes have complex underlying chemical kinetics (Nozari and Karabeyoglu, 2016).

In addition, with further technological progress, ammonia could become an attractive propellant for land transportation and a sustainable alternative to bunker fuel (heavy fuel oil) which is currently used in maritime transport. However, the design of new vessels will have to adjust to this type of marine fuel, as, while requiring less storage space than hydrogen, ammonia still occupies substantially more volume than diesel for the same propulsion amount (Green Tech Media, 2020). Furthermore, although the direct consumption of ammonia is less complex from a technical perspective, measures still need to be taken to address NOx emission. The use of ammonia in fuel cells rather than in internal combustion engines

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[4] $4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$

could effectively address the NOx pollution challenge and provide a better overall performance; however, there is a greater level of technical challenges to overcome in ammonia-fuelled fuel cells. Therefore, at the moment, the issue of using NH_3 in the carbon-free shipping economy appears to be at an early stage of its development (ibid).

Another alternative approach to the direct combustion of ammonia is to utilize it as the energy vector of hydrogen, where ammonia could be viewed as its storable source, while the direct storage and transportation of hydrogen in large quantities is still challenging and expensive (Valera-Medina, 2018, p. 76). Ammonia contains 17.5 wt per cent[5] hydrogen, which makes it an ideal (and potentially carbon-free) fuel for fuel cells that is easy to preserve and transport (Lan and Tao, 2014, pp. 1). Additionally, H_2 generated from NH_3 can be combusted with 'high power output, high efficiency, and ultra-low emissions' (Verhelst et al., 2011, p. 427). In this case, hydrogen-fuelled internal combustion engines will only produce water vapour – that is, neither carbon dioxide nor soot (just as in the case of combusted ammonia): $H_2 + ½O_2 \rightarrow H_2O$ (ibid). Furthermore, much of the existing combustion equipment only needs minor adjustments to accommodate hydrogen. However, due to practical issues with storing hydrogen in a quantity suitable for direct combustion, the preferred approach to using hydrogen in the long term is via fuel cells. This process, which essentially is the reverse of electrolysis, combines hydrogen and oxygen in the presence of a catalyst to generate electricity, with only water as the by-product. Fuel cells are more efficient than direct combustion of hydrogen; however, the main issue with fuel cells is the cost. Overall, irrespective of the way hydrogen is used as a new fuel, integrating ammonia into the energy system as an energy vector of hydrogen seems to be the way forward.

3.2. Ammonia production methods

Presently, more than 90 per cent of the world's ammonia production is realized through a process called the 'Haber–Bosch synthesis' which was developed in the first decade of the 20th century (Bicer et al., 2016, p.1379). This process combines hydrogen (H_2) and nitrogen (N_2) with the help of a catalyst. It is energy intensive and requires high pressure and temperatures, which are usually provided using fossil fuels (ibid).

The Haber–Bosch synthesis represents only the final stage in ammonia's production and utilizes about a third of the energy involved in the total process, whereas two thirds of the energy is spent on the generation of ammonia's components – hydrogen and nitrogen (Bañares-Alcántara et al., 2015). In other words, prior to the NH_3 synthesis itself, both H_2 and N_2 need to be obtained, and this process is very energy intensive.

The key stages of the main commercial and industrial processes that are currently used for stable ammonia manufacturing are summarized in Figure 4.

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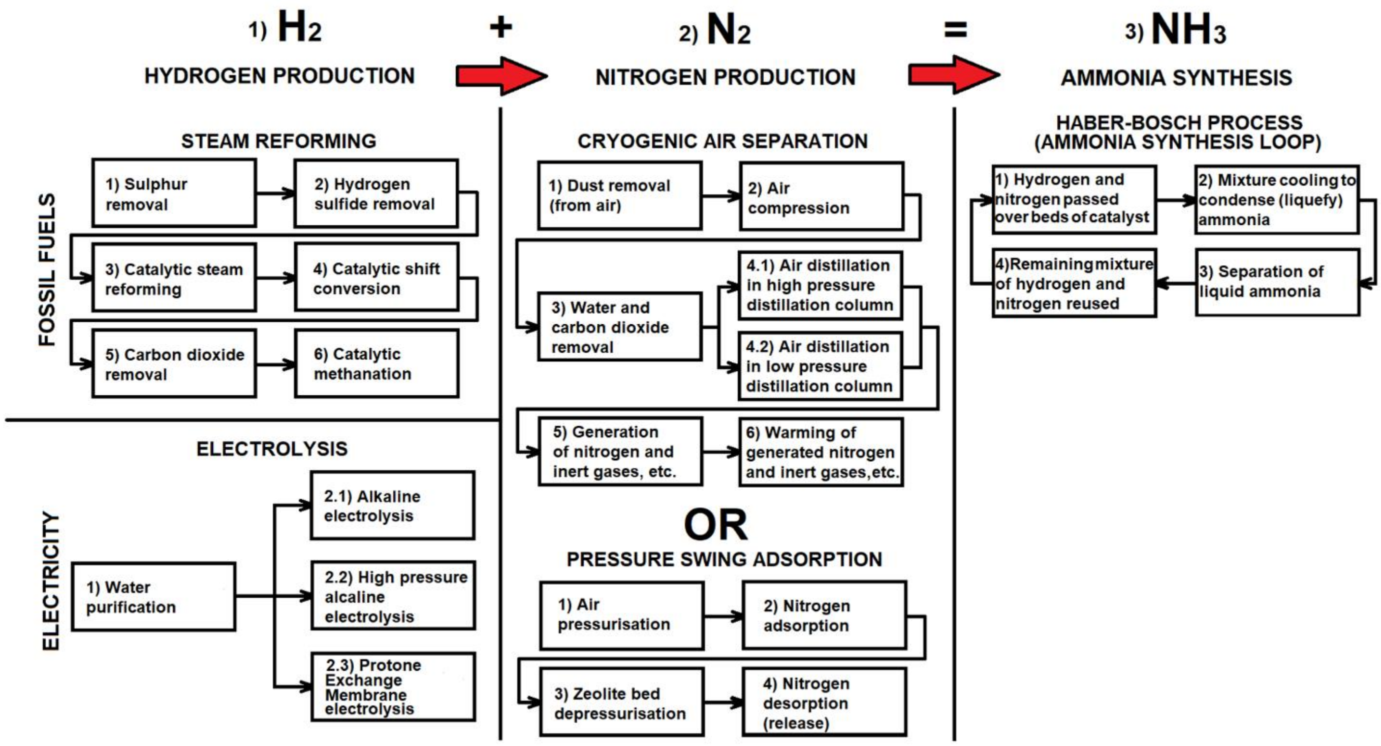
[5] wt%' is 'weight per cent' – i.e. mass percentage.

Figure 4: Feasible technologies of ammonia production by stage[6]



Sources: authors adapted from Kalamaras and Efstathiou (2013), Bañares-Alcántara et al. (2015), Bicer et al. (2016)

Hydrogen production

Hydrogen production is often considered the first stage in the generation of ammonia and is also highly energy demanding. Hydrogen is currently mainly produced through a process called *steam reforming*. The reason for the widespread use of steam reforming for hydrogen generation is its high operational efficiency and low cost (Kalamaras and Estathiou, 2013, p.2). However, the high efficiency and cost advantage are due primarily to the use of hydrocarbons (and most popularly methane) as raw materials. Currently, the steam reforming of natural gas is the least expensive method of hydrogen production (ibid, p. 7).

As seen from Figure 4, this conventional hydrogen production process starts with the removal of sulphur (1) because most fossil fuels contain a certain amount of sulphur that can easily deactivate the catalysts used in each of the main processes of the NH_3 generation cycle (Kalamaras and Efstathiou, 2013, p.2). Then, gaseous hydrogen sulphide is absorbed and removed (2) while being passed through zinc oxide, where it is converted to solid zinc sulphide.

Once the feedstock has been made sulphur-free, it is then utilized to create hydrogen and carbon monoxide through the process of catalytic steam reforming itself (3). Later, catalytic shift conversion transforms the carbon monoxide into carbon dioxide and hydrogen (4). Then, CO_2 is removed either in aqueous ethanolamine solutions or pressure swing adsorbers (5). Finally, the remaining residual CO and CO_2 present in the produced hydrogen are separated though catalytic methanation (6).

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[6] Ammonia production reaction: $N_2 + 3H_2 \leftrightarrow 2NH_3$

The steam reforming of hydrocarbons is not the only method of hydrogen production. As can be seen from Table 2, for example, plasma technologies could potentially allow for significant energy savings, due to their lower energy consumption, while offering efficiency levels comparable with those offered by steam reforming. However, autothermal and plasma, as alternative reforming methods of hydrogen production, are not currently available on an industrial scale. The aqueous phase reforming of carbohydrates is yet to be become commercially viable.

There are also other methods of hydrogen production, such as

- gasification, which often uses biomass as feedstock,
- photolysis based on water and sunlight,
- the partial oxidation of hydrocarbons.

However, photolysis is not yet commercial whereas gasification and the partial oxidation of hydrocarbons are less efficient than steam reforming.

An alternative approach is electrolysis, for which various technologies exist such as atmospheric alkaline, high-pressure alkaline, and proton exchange membrane. Electrolysis is based on the principle of the decomposition of water into its constituent elements (hydrogen and oxygen) by means of applying an electric current and it is currently responsible for the production of around 3.9 per cent of the world's hydrogen, (ibid, p.1). Here, (see Figure 4), with the main differences attributed to the type of the electrolyser, the process of producing hydrogen from water normally has only two phases: water purification (1), and electrolysis itself (2).

In contrast with steam reforming, electrolysis is more energy intensive and has a lower overall efficiency. Nonetheless, with the ongoing cost decline in renewable electricity and the possibility of improvements in electrolysis technology, it has the potential to become the prime method of hydrogen production in the future.

The final method of hydrogen production – based on thermochemical water splitting – has yet to be developed.

Table 2: Main ammonia production technologies: Summary by stage[7]

Stages	**Technology**		**Technology readiness level**	**Feedstock**	**Driving force (type of energy used)**	**Approximate energy consumption**	
						MJ/kg	**kWh/kg**
Hydrogen production[8]	*Reforming*	Steam	Commercially used	Hydrocarbons	Fossil fuels	165–180	45.8–50
		Autothermal	To-be-developed in short term			n/a	
		Plasma	To-be-developed in long term			29–31.8	8.05–8.83
		Aqueous phase	To-be-developed in medium term	Carbohydrates	Fossil fuels-to-electricity/ nuclear/ renewables	n/a	
	Gasification		Commercially used	Biomass		<=151.2	<=42
	Photolysis		To-be-developed in long term	Water and sunlight		n/a	
	Partial oxidation		Commercially used	Hydrocarbons	Fossil fuels	~120	~33.3

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[7] Direct electrochemical reduction of dinitrogen ($N_2 + 3H_2O \leftrightarrow 2NH_3 + 1.5O_2$) is not included due to the technological immaturity of the process.

[8] Hydrogen purification excluded.

	Electrolysis	Atmospheric alkaline	Commercially used	Water and electricity	Fossil fuels-to-electricity/ nuclear/ renewables	188.96–192.24	52.5–53.4
		High pressure alkaline					
		Proton exchange membrane				*224.28–252.36*	*62.3–70.1*
	Thermochemical water splitting		To-be-developed in long term	Water and heat		n/a	
Nitrogen production	*Air separation*	Adsorption	To-be-developed in short term	Air, electricity, heat	Fossil fuels/ fossil fuels-to-electricity/ nuclear/ renewables		
		Chemical	To-be-developed in long term				
		Cryogenic	Commercially used	Air and electricity	Fossil fuels-to-electricity/ nuclear/ renewables	*0.86–1.98*	*0.24–0.55*
		Polymeric membrane	To-be-developed in short term			n/a	
		Ion transport membrane	To-be-developed in long term	Air, electricity, heat	Fossil fuels/ fossil fuels-to-electricity/ nuclear/ renewables		
	Pressure swing adsorption		Commercially used	Air/biogas (landfill gas) and electricity		0.4-1.04	0.11–0.29
Ammonia synthesis	*Haber-Bosch*	Fe catalyst		Air, electricity, heat		14.4–28.44	4–7.9
		Ru catalyst					
		Co_3Mo_3N catalyst					
	Electrolytic (electrochemical) synthesis	Liquid electrolyte	To-be-developed in long term	Electricity	Fossil fuels-to-electricity/ nuclear/ renewables	*35.64–41.4*	*9.9–11.5*
		Molten salts					
		Composite membrane					
		Solid state electrolyte	To-be-developed in medium term			<=35,64	<=9.9

Sources: authors adapted from Smith and Klosek (2001), Kim et al. (2006), Chao et al. (2008), Centre for Low Carbon Futures (2013),Giddey, Badwal, and Kulkarni (2013), Kalamaras and Estathiou (2013), Garagounis et al. (2014), Aneke and Wang (2015), Bañares-Alcántara et al. (2015), Chorzowski and Gizicki (2015), Ray (2015), Rutberg et al. (2015), Bicer et al. (2016), McEnaney et al. (2017), Rao and Dey (2017), Mehmeti et al. (2018), Soloveichik (2019), Yang, Weng, Xiao (2019)

Nitrogen production

The production of nitrogen – another phase preceding the ammonia production loop – is currently conducted through either cryogenic air separation or pressure swing adsorption (Bañares-Alcántara et al., 2015). Although both methods allow for successful N_2 generation, cryogenic air separation represents the most popular approach because it is more suitable for production on an industrial scale (ibid). However, both methods usually utilize fossil fuels such as natural gas, fuel oil, and naphtha as a feedstock to create the right pressure and temperature (Ray, 2015).

- Cryogenic air separation

Based on a similar principle – utilizing the various boiling temperatures of different gases – cryogenic air separation generally represents the process of selective distillation of the required elements (here, nitrogen) from air that is cooled until it is liquid (Ray, 2015). The stages of this process are shown in Figure 4. For the same, previously mentioned, reasons that pure hydrogen is required, the Haber–Bosch process also requires high purity nitrogen. Air separation starts with dust removal from the air (1) and then moves to the compression of the purified air (2) to facilitate efficiency enhancement. Later, molecular sieves remove water and carbon dioxide (3). Then, the already processed air is passed through the heat exchanger and cooled so that it can be distilled either in a high pressure (4.1) or a low pressure distillation column (4.2). Through this process, nitrogen is separated from the rest of the gases present in the mixture (normally argon and oxygen) (5), as its boiling point (–195.8^{o}C) lies below those of oxygen (–183^{o}C) and argon (–185.8^{o}C). Finally, the produced gases are warmed (6).

- Pressure swing adsorption

In contrast to cryogenic air separation, pressure swing adsorption is based on a different principle. In particular, instead of focusing on the different boiling points of the gases present in the air, it uses their unique characteristics, observed under pressure and specific adsorbent materials, as a trap (Kim et al., 2006). The stages of this process are described in Figure 4. Taking advantage of the fact that pressurized gaseous substances are attracted to certain solid surfaces, this process starts with air pressurization (1) directly followed by the adsorption of nitrogen by a zeolite bed (2). Later, low pressure is applied to the zeolite bed itself (3) to desorb (that is, release) the separated nitrogen (4). Although the process contains fewer phases than conventional cryogenic air separation, its industrial scalability is currently limited (ibid).

As neither nitrogen production technique specifically requires fossil fuels as a feedstock, the temperature and pressure required can potentially be created and maintained by electricity. Indeed, as nitrogen is generated from the air, energy from nuclear or renewable energy sources could replace hydrocarbons and thus make the process more environmentally friendly.

- Other methods of nitrogen production

Other methods of nitrogen production that potentially offer high efficiency levels are still at the development phase and are thus not industrially implemented (Kim et al., 2006 and Bañares-Alcántara et al., 2015). For instance, the development of solutions such as *ion transport membranes* and *air separation through adsorption*, *chemicals* and *polymer-based membrane* will only be scaled up in the future. At the same time, both of the already available techniques – namely *cryogenic air separation* and *pressure swing adsorption* – can potentially operate on electricity and thus could be integrated into the 'green' ammonia production cycle. Although consuming more energy per kilogram of output, cryogenic air separation can allow for a greater scale of nitrogen generation and is thus potentially more suitable for large production facilities (Bañares-Alcántara et al., 2015, p. 34). On the other hand, being less complex and offering more humble nitrogen production levels at lower efficiency, pressure swing adsorption appears to be a technology suitable for offering small-scale production of nitrogen (ibid).

Ammonia synthesis loop

The final stage is the synthesis of ammonia itself, which is mainly carried out through the Haber–Bosch process (see Figure 4). It represents a mechanism for artificial nitrogen fixation and is based on passing gaseous nitrogen and hydrogen over beds of catalysts (1) so that ammonia can be generated:

N_2 (gas) + $3H_2$ (gas) $\leftrightarrow$ $2NH_3$ (gas) (see stages in Fig 4).

Traditionally, Iron (Fe), Ruthenium (Ru), or Cobalt Molybdenum Nitride (Co_3Mo_3N) catalysts with KOH (potassium hydroxide) promoter are used to assist the reaction, since gaseous nitrogen is extremely unreactive (Modak, 2002). Next, the mixture of gases is cooled to condense (2), and liquefied NH_3 is then separated (3). Despite the use of catalysts, the efficiency rate of conversion is low (less than 50 per cent) and most of the mixture still represents a blend of hydrogen and nitrogen. Thus, the mixture is sent for the next cycle (or cycles) (4) to maximize the overall conversion rate.

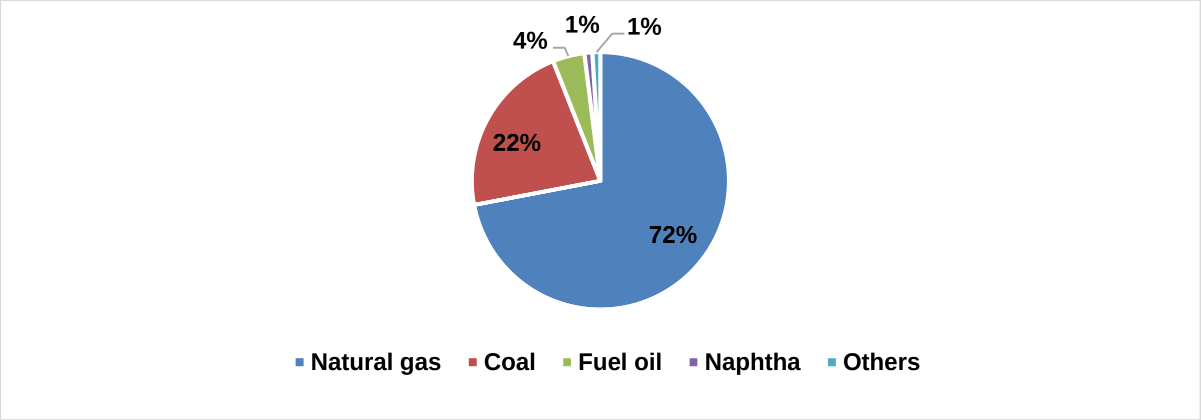
The alternative approach is *electrolytic ammonia synthesis*. The energy consumption of electrolytic synthesis is, however, more intense when compared with the Haber–Bosch process (9.9–11.5 kWh/kg vs.4–7.9 kWh/kg) and it is not yet established for industrial production (Soloveichik, 2019, p.377). Solid state electrolytic technology, as the most promising solution in this category, is not yet ready for commercial production, but it is expected to be industrially tested in the foreseeable future (Bañares-Alcántara et al., 2015, p. 39). Therefore, until an alternative more efficient approach, which is scalable to industrial level, is developed, the Haber–Bosch process seems to represent the mainstay of the industrial production of ammonia from hydrogen and nitrogen.

4. The key challenge of ammonia production

The manufacturing of ammonia is an established process, and thus the main challenge is not how to produce it at an industrial scale with minimum cost, but to how to produce it carbon-free and, simultaneously, cost efficiently. Given that nowadays the entire ammonia manufacturing process is conducted within the same plant, all three stages of NH_3 generation are generally reliant on a single type of fossil fuel, of which natural gas is the dominant feedstock (Figure 5). As a result, ammonia produced conventionally through steam reforming, air separation, and the Haber–Bosch process is argued to be the direct cause of 1.44 per cent of global CO_2 emissions (Kyriakou et al, 2019, p.1) This is also partly because NH_3 represents the most energy-intensive commodity chemical, responsible for 1–2 per cent of global energy consumption (ibid). Thus, shifting from the current dominant production method of ammonia to ones that are not based on hydrocarbons and do not emit CO_2 could be viewed as a means of not just facilitating a green energy economy but also of decarbonizing an energy-intensive chemical product.

For the Haber–Bosch process, a simple switch from fossil fuels to electricity will not lead to an increase in efficiency, but it will cut emissions by approximately one third (Bañares-Alcántara et al. (2015). If the phases prior to the ammonia synthesis loop are also electrified, there will be positive environmental impacts as well as an efficiency advantage. For example, electrification of the hydrogen generation phase (replacing steam reforming with electrolysis) will increase the efficiency of the subsequent stages, as generating high purity hydrogen can help to prevent inactivation of catalysts.[9] Nitrogen generation and ammonia synthesis are generally more flexible in terms of the energy type that can be used for their production. In other words, these processes can switch from fossil fuels to electricity without a major hurdle and thus be adjusted to the needs of decarbonization policies through running on non-hydrocarbons – electricity generated by either nuclear power or renewables. However, this is not straightforward for hydrogen. Thus, the key challenge of green ammonia production is carbon-free hydrogen production.

Figure 5: Feedstock source for ammonia production



Sources: NR, 2007 and IIP, 2015 cited in Bicer et al., 2016, p. 1380

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[9] Indeed, ‘oxygen or oxides must not enter the synthesis loop since this would inactivate the catalyst’ and thus reduce the efficiency of the process (Pfromm, 2017, p. 3).

4.1. Steam reforming vs. electrolysis in hydrogen production

As one of the core process of manufacturing ammonia, hydrogen production defines the type of energy used in the later phases of NH_3 generation. Since fossil fuels still constitute the lion's share of the world's primary energy use, the popularity of hydrocarbons-based steam reforming over other methods is not surprising (EESI, 2019). However, the need to achieve decarbonization targets requires reduction in the use of combustion-driven technologies, while intensifying electrification; hydrogen production based on electricity is thus expected to gain greater attention (World Energy Council, 2019). In this sense, if major ammonia producers replace steam reforming with electrolysis, the entire industry will potentially be transformed, in response to the new sustainability requirements. This, however, entails significant changes in the process of ammonia production, as the feedstock used by each technology is very specific.

Currently, based on the catalyst-assisted reaction of higher hydrocarbons with steam (forming carbon oxides and hydrogen), steam reforming usually utilizes methane as its primary feedstock in the production of hydrogen. At the global level, close to 50 per cent of hydrogen demand is met via the steam reforming of natural gas (Kalamaras and Efstathiou, 2013, p.1). In contrast to steam reforming, electrolysis not only uses a completely different feedstock (water), but also represents a process with fewer phases. Overall, this approach to hydrogen production has a number of advantages when compared to steam reforming.

Advantages of electrolysis

High purity of hydrogen. Since hydrogen and oxygen are the only products of the decomposition of water, by means of an electric current, the presence of other elements does not have a significant influence on the hydrogen production process. Therefore, electrolysis could be considered as a convenient and established technology which can produce pure hydrogen (Scott, 2019, p. 25). The production of high-quality hydrogen that needs no further purification could be considered a significant advantage for the later stages of ammonia production, as each stage utilizes catalysts that are sensitive to any impurities in the components.

Lower complexity. Due to the smaller number of stages involved in the process of hydrogen generation, electrolysis represents a less complex mechanism and thus 'has the advantages for generating hydrogen at small facilities for localized high-purity hydrogen and oxygen supplies' (Revankar, 2019, p. 49). It can thus potentially assist in spreading ammonia production beyond large-scale NH_3 generation plants. For instance, small electrolysers could be integrated into intermittent power generation plants (such as wind or solar). Similarly, hydrogen production facilities could be installed at hydropower or nuclear power plants, potentially utilizing excess electricity.

Lower capital costs. Although the scale of appliances for electrolysis-based hydrogen production may be less impressive than those for steam reforming, even the cost of installing small electrolysers with water purifiers will represent a lower capital cost than installing water purification facilities in fully fledged steam reformers with all their accompanying devices.

Absence of pollution in the production process. With the significant negative environmental impact associated with steam reforming, electrolysis is 'ecologically clean because no greenhouse gases are formed during the hydrogen production, and the oxygen produced has further industrial applications' (Kalamaras and Efstathious, 2013, p.6). Although CO_2 emissions associated with the electricity used are not often considered, these aspects should not be excluded from the estimation of hydrogen production costs.

Disadvantages of electrolysis

Despite the aforementioned advantages, hydrogen production by means of electrolysis has three main drawbacks and challenges.

The infrastructure is set for steam reforming. Due to the fact that steam reforming is the dominant technology, most of the hydrogen- and ammonia-production infrastructure is adjusted to hydrocarbons as a feedstock. In this respect, switching from hydrocarbons to electricity may require additional costs associated with the conversion of existing facilities, or the construction of new ones. Indirect costs – such as the development of new energy infrastructure (for example, renewable power and extensions to the grid) and the replacement of old energy infrastructure (like gas turbines and pipelines) – should be added to the expenditures associated with the replacement of steam reformers with electrolysers. Since these costs seem to be expensive, they are likely to hamper the transition process.

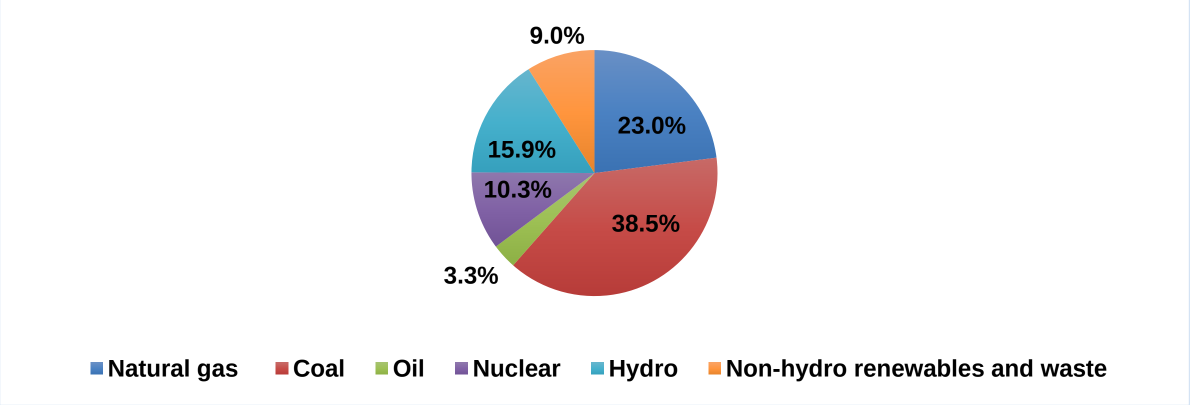
Lower efficiency. The thermal efficiency of steam reforming is currently between 70 and 85 per cent, whereas the (electrical) efficiency of electrolysis varies between 50 and 70 per cent. Although it is possible that the efficiency of electrolytic hydrogen production could rise to about 85 per cent with technological improvement (SINTEF, 2015), an efficiency level comparable to steam reforming is yet to be reached.

Lower production efficiency makes economics of electrolysis weaker than for steam reforming. Indeed, the average energy consumption per kg of hydrogen varies between 52.5 and 70.1 kWh for electrolysis, whereas it only reaches 50 kWh in the case of steam reforming (see Table 2). As, at the moment, natural gas 'is cheaper than other fuels' in most cases, it will be economically feasible to prefer electrolytic hydrogen generation to steam reforming only when electricity is cheaper than natural gas, ceteris paribus (Di Pascoli, Femia, and Luzzati, 2001, p. 187).

4.2. The choice between electrolysis and steam reforming in a net zero future

Currently, the price for natural gas (methane) is generally several times lower than the price for electricity in most countries of the world. In September 2019, the world average retail price for electricity was 0.15 USD/kWh for households and 0.13 USD/kWh for businesses, whereas the natural gas equivalent was only 0.06 and 0.05 USD/kWh, respectively (Global Petrol Prices, 2019a and Global Petrol Prices, 2019b). This substantial price difference is partly due to the fact that electricity is a secondary energy source whereas natural gas is a primary energy source (EIA, 2019). Globally, more than 60 per cent of generated electricity is derived from hydrocarbons (Figure 6).

Figure 6: Source shares of electricity generation



Source: IEA (2019a)

For illustrative purposes, we make a simple comparison between the energy cost of producing hydrogen through steam reforming versus electrolysis, using the aforementioned retail prices for natural gas and electricity (we are aware that these may not be realistic prices for this purpose, however, given the spread between gas and electricity prices per kWh, our argument here still holds). As it was shown in Table 2, steam reforming, as the more efficient process, requires between 45.8 and 50 kWh per kg of hydrogen, in comparison to 52.5–70.1 kWh in the case of electrolysis. Therefore, taking the average price of natural gas and electricity for industries and the average energy consumption, we could calculate the average energy cost per kg of hydrogen for each technology as follows:

a) ***Steam reforming:*** 45.8–50 kWh/kg * 0.05 USD/kWh = 2.29–2.5 USD/kg

b) ***Electrolysis:*** 52.5–70.1 kWh/kg * 0.13 USD/kWh = 6.83–9.11 USD/kg

Although the above calculation is very simplistic and the actual costs of hydrogen produced by steam reforming and electrolysis vary from place to place, it is easy to see that, on average, the energy cost per kg of H_2 produced through steam reforming is around three to four times lower than through electrolysis. In other words, with similar operating costs, to achieve the same price per kg of H_2, an average electrolyser should use electricity at a price which is three to four times lower than the current average price of electricity – namely 0.033–0.043 USD/kWh instead of 0.13 USD/kWh.

On the other hand, while being more economically attractive, steam–methane reforming does not provide a direct solution to the challenge of carbon emission. Although using natural gas, in contrast to coal, naphtha, or fuel oil, could potentially be viewed as a more environmentally friendly approach to the process, carbon dioxide emissions are unavoidable since they are still part of the chemical reaction (as shown in the formulae below):

$CH_4 + H_2O \rightarrow CO + 3H_2$ (Steam–methane reforming reaction)

$CO + H_2O \rightarrow CO_2 + H_2$ (Water–gas shift reaction)

This means that if the net zero target is to be met without completely abandoning the original feedstock, ammonia producers will have to invest in carbon capture and storage (CCS). CCS is an important option for decarbonizing certain industrial processes, and is a key technology for decarbonizing energy systems which have a high share of fossil fuels (World Energy Council, 2016). Operating CCS facilities in parallel with running conventional ammonia production will result in further expenses being added to the ultimate cost of hydrogen, and thus ammonia. Although avoided CO_2 costs will depend on a number of factors, the type of feedstock used will be the most significant factor in determining their variability (Global CCS Institute, 2017). For the ammonia production industry, the added costs resulting from the use of CCS are estimated to vary between 23.8 and 25.4 USD/tonne – namely 0.025 USD/kg CO_2-eq on average (ibid[10]).

To incentivize ammonia producers to adopt low-emission approaches, there is a need for either direct regulation or taxation of CO_2. This would account for the economic damage caused by each marginal tonne of carbon dioxide emissions (Institute for Policy Integrity, 2015, p. 18) in the final price of the hydrogen and ammonia generated. A widely adopted metric is the social cost of carbon (SCC). Although there is no global consensus on its exact value, in 2015, the SCC had been expected to grow in subsequent decades from about 15 to about 60 USD/tonne, with the annual levelized cost varying between 26.24 and 59.35 USD/tonne (Luckow et al., 2015). If we take this estimation, the average SCC per kg of CO_2-eq would be around USD0.043. Although this value is greater than the value assessed by the US Environmental Protection Agency (USD0.036), it is close to USD0.045 – namely the SCC price set by the Obama administration (Bordoff, 2017 and Fleurbaey, et al., 2019).

This level of carbon tax is too low to effectively achieve a market-based transition away from fossil fuels, and some countries have increased the carbon tax. For instance, while Finland's tax per tonne of CO_2 reached USD65 in 2017, Sweden 'disincentivized' potential polluters, forcing them to pay twice that amount (USD131) (Carbon Market Watch, 2017). On the other hand, some other countries have introduced significantly lower carbon taxes. In particular, with Denmark and France setting the tax bar at about half the average level (at 26 and 25 USD/tonne CO_2, respectively), Ireland lowered it even

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[10] The costs estimated by IEA (2019c, p. 40) for the integrated ammonia/urea plants are even higher: USD90–115 t/CO_2

further – to 22 USD/tonne CO_2 (ibid). Hence, with no universal agreement on the adequate price for carbon, the actual carbon tax level appears to reflect the value judgements of the respective governments.

There are also governments which have adopted tradeable emission certificates (as an alternative to or in addition to carbon tax), by regulating the total emission volume through the introduction of caps. In this approach, the price of carbon dioxide per tonne will be volatile and will not necessarily reflect the social cost of such emissions. For example, in 2017, the weighted average trading prices per tonne of CO_2 in countries such as South Korea and New Zealand were USD18.81 and USD12.01, respectively; however, in China, the world's top polluter, it was only USD5.74 (Carbon Market Watch, 2017 and International Carbon Action Partnership, 2020).

Currently, most of the world's countries have neither carbon tax nor emission trading schemes (World Bank, 2020) and this makes estimation of the total actual cost of steam reforming difficult. However, for illustration, if we consider the price tag of 0.043 USD/kg of CO_2-eq and using the estimated amounts of pollution from the steam reforming process (based on different types of feedstock), the approximate costs of CO_2 avoided and left in the process of hydrogen production could be represented as in Table 3:

Table 3: Approximate pollution levels of steam reforming technologies by feedstock and the cost of CO2 avoided and left

Feedstock	General pollution level (kg CO_2-eq/kg H_2)	Pollution level with CCS (kg CO_2-eq/kg H_2)	Cost of CO_2 avoided (USD/kg H_2[11])	Cost of CO_2 left (USD/kg H_2[12])
Coal	18–21.39	~4.08	0.35–0.43	0.18
Natural gas	8.9–12.9	3.07–3.4	0.15–0.24	0.13–0.15
Naphtha	~9.46	~3.9	~0.14	~0.17
Fuel oil				

Sources: Adaptation from Dincer, Colpan, and Kadioglu (2013), Luckow et al. (2015), Global CCS Institute (2017) and Mehmeti et al. (2018)

Given the data presented above, it could be calculated that the average cost of hydrogen produced from steam reforming of methane will rise up to at least 2.57–2.89 USD/kg:

Energy cost (2.29–2.5) + Cost of CO_2 avoided (0.15–0.24) + Cost of CO_2 left (0.13–0.15) = Cost of hydrogen (2.57–2.89 USD/kg)

This means that in order to generate hydrogen at the same cost, electrolysers would need electricity prices to be between 0.041 and 0.049 USD/kWh:

Hydrogen cost (2.57–2.89 USD/kg) / Energy consumption (52.5–70.1 kWh/kg) = Electricity prices (0.041–0.049 USD/kWh)

Apart from being almost the same as the assumed average price of natural gas (0.041–0.049 vs. 0.05 USD/kWh), such prices for electricity (and even lower) are thus potentially achievable. With the 2020 target on the levelized cost of hydrogen being 2.30 USD/kg, the US Department of Energy (2019) considers the feasible electricity price for 'green' hydrogen production facilities to be 0.037 USD/kWh.

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[11] Cost of CO_2 avoided (USD/kg H_2) = (General pollution level (kg CO_2-eq/kg H_2) – Pollution level with CCS (kg CO_2-eq/kg H_2)) x Average cost of CO_2 avoided (USD/kg CO_2-eq)

[12] Cost of CO_2 remaining (USD/kg H_2) = Pollution level with CCS (kg CO_2-eq/kg H_2) x Average SCC (USD/kg of CO_2-eq)
Here, the cost of CO_2 remaining varies among the different types of feedstock, as the implementation of CCS also leaves different pollution levels.

Given the falling cost of solar and wind power in recent years (especially in the areas most suitable for the placement of these resources), achieving such a cost for electrolytic hydrogen generation is not impossible.

An important point to note is that the costs of steam reforming are also very much contingent upon the scale of the reforming facilities. Indeed, the cost of producing hydrogen via steam reforming of natural gas (methane) varies from around 1.25 USD/kg for large systems to about 3.50 USD/kg for small ones (Dagdougui et al., 2018, p.11). While there are large benefits from economies of scale in centralized production, distributed (in other words, decentralized) production infrastructure at smaller scale, based on conventional technology, could potentially be more expensive than the green distributed system based on electrolysis. Therefore, small-scale decentralized systems are likely to be the pathway for the future development of the ammonia industry in a decarbonized environment (ibid). This is feasible, especially because of the cost decline of decentralized resources and the very low marginal cost of renewable electricity.

Apart from becoming economically attractive, with the gradually falling costs of renewable electricity, electrolysis-based hydrogen production offers additional advantages in comparison to hydrocarbons-based steam reforming. Specifically, CCS applications at their current stage of technological development do not allow for achieving a fully carbon-free process. In particular, as seen from Table 3, though significantly reducing CO_2 emissions, they do not fully absorb the entire amount of carbon dioxide generated during the hydrogen production process. Indeed, even the estimates including just the ‘carbon captured from energy production at a fossil fuel plant itself and not upstream emissions’ assume that CCS can ‘remediate 85–90 per cent of carbon emissions’ (Stanford News, 2019). However, in the case that all the upstream emissions associated with power plants are included, the actual amount of CO_2 captured is likely to be even lower – down to 11 per cent, as the Stanford University research demonstrates (ibid and Jacobson, 2019[13]).

While currently being characterized with relatively low overall capture efficiency, CCS applications will generate additional capital, operating, and maintenance costs. These expenses, however, may not guarantee that the carbon dioxide stored is safely kept for the entire duration of the facility’s operation. Indeed, as most CCS technologies presuppose the injection of pollutants into underground formations, ‘potential CO_2 leakage is a major concern for geological storage’ (Leung, Caramanna, and Maroto-Valer, 2014, pp. 435). Additionally, such an approach puts significant limitations on the use and scale of CCS technologies with respect to hydrogen and ammonia production. In particular, it currently almost completely excludes the possibility of applying them at the small-scale facilities of smaller businesses, giving priority instead to large capital-intensive investment projects.

Finally, a facility with a CCS system ‘would also need roughly 10–40 per cent more energy than a plant of equivalent output without CCS’ (Eldariry and Habib, 2018, p.2). Hence, to maintain hydrogen production at the same level, more hydrocarbons will have to be combusted to cater for the production itself and for the carbon capture. In this sense, using CCS instead of promoting renewable H_2 generation will create a perverse incentive to intensify emissions, instead of reducing pollution to comply with net zero objectives. Thus, combining steam reforming with carbon capture and storage will bear an additional negative social cost, when compared to the use of renewables.

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[13] ‘Upstream emissions are emissions, including from leaks and combustion, from mining and transporting a fuel such as coal or natural gas’ (Stanford News, 2019).

5. Green ammonia and investors

5.1. Key cost factors of green ammonia production

Traditionally, ammonia generation has been organized to favour large-scale industrial production for the purpose of utilizing economies of scale and thus minimizing costs (Ammonia Industry, 2018). This is not surprising given the historical demand growth for ammonia. Indeed, ‘the tremendous increase in ammonia demand from 1950 to 1980 necessitated larger, more energy-efficient plants’ (Pattabathula and Richardson, 2016, p. 70). As a result, most plants that were built between 1963 and 1993 had large single-train designs (ibid, p. 71). This trend still continues to date, and despite the feasibility of the distributed production of ammonia in small ammonia plants, most producers prefer to build large facilities near cheap raw material sources (ibid, p.74). Scale efficiency is thus a key investment determinant. Currently, in many places such as the USA, the cost of ammonia generated by conventional gas-powered small-scale facilities significantly exceeds the cost associated with the respective large-scale installations (see Table 4):

Table 4: Approximate estimated costs of ammonia production in the US for gas- and electricity-powered projects (USD/mt-NH_3) in 2017[14]

Plant size		**Large**			**Medium**			**Small**		
Production per day (mt-NH_3/day)		~ 2000			~545			~91		
Type of feedstock		Natural gas	Electricity		Natural gas	Electricity		Natural gas	Electricity	
			H_2	Haber–Bosch		H_2	Haber–Bosch		H_2	Haber-Bosch
Expenses (USD/mt-NH_3)	**Feedstock/energy**	93	441	67	93	441	67	93	441	67
	Capital	55	33	32	88	33	51	113	33	66
	Operations & maintenance	22	41	13	62	41	36	133	41	77
	Total	**170**	**627**		**243**	**669**		**339**	**725**	

Sources: Authors’ adaptation from Hochman, et al. (2019)

As seen from Table 4, the cost of ammonia produced with electricity does not have a large variance based on the size of the production facility, as the difference between the total cost of a metric tonne of NH_3 associated with large- vs. small-scale plants is USD98. Although this seems like a significant sum per se, it is less substantial when compared to the total cost of ammonia produced with electricity in large- vs. small scale electric plants (627 USD/mt-NH_3 vs. 725 USD/mt-NH_3). In comparison, the ammonia costs related to small conventional installations are twice the costs of large-scale plants of conventional type (339 USD/mt-NH_3 vs. 170 USD/mt-NH_3).

Specifically, when natural gas is used as a feedstock, reducing the operation size from large to medium (namely shrinking it by 3.6 times which is 2000/545) will result in an increase in the cost of production by 42 per cent. However, this number is only 6.7 per cent when the feedstock is electricity. This suggests that the development of small-scale facilities for the generation of green ammonia by means of electrosynthesis is unlikely to be tremendously different in terms of costs from that of large-scale ones for the same purpose. Therefore, with the rapid growth of decentralized renewables generation

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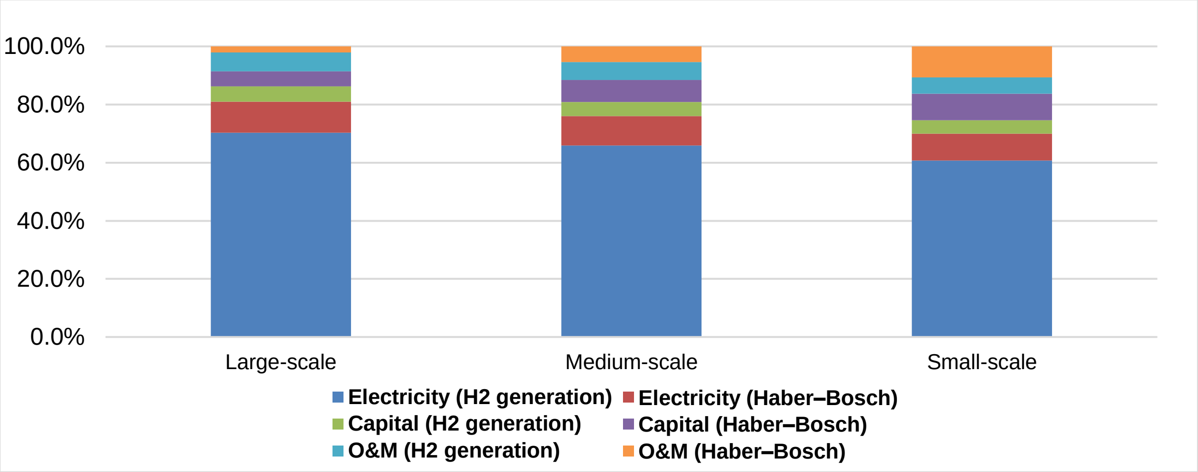
[14] Calculations for conventional ammonia production are based on the cost of natural gas equalling 3.08 USD/MBTU. Here, MBTU should be read as ‘million British thermal units’. For the electrolysis-based ‘green’ NH_3 generation, the electricity cost of 50 USD/MWh is used.

technologies in the future, electricity-based NH_3 production is likely to be organized and expanded in the form of a small- or medium-scale operations.

Indeed, in contrast to the previous trend – which was moving towards larger and ever larger production facilities – a new trend is expected to emerge that moves towards smaller plants. These will, however, be sufficiently large to serve a regional market while representing a viable business model (Ammonia Industry, 2018a). Although in the US model, demonstrated in Table 4, the cost of green ammonia is significantly higher than the cost of NH_3 obtained through conventional processes, this may not necessarily be the case everywhere, as the actual costs are highly place-specific. In other words, under certain conditions, electricity-based ammonia production may be cost-competitive with conventional gas-based generation.

To identify these conditions, it is useful to review the previously described US model from a different perspective – namely, highlighting all the components of the final NH_3 cost (see Figure 7).

Figure 7: 'Green' ammonia production costs by components



Sources*:* Authors' adaptation from Hochman, et al. (2019)

The key cost components of green ammonia production are electricity, capital investment, and operations and maintenance (O&M). As seen from Figure 7, with a share of around 80 per cent in large- and 70 per cent in small-scale installations, the electricity costs significantly outweigh the rest of the components. At the same time, capital[15] and O&M costs – jointly varying between 30 and 20 per cent for small- and large-scale facilities – still represent a substantial share. These three categories of expenses will have a direct impact on the ultimate cost of ammonia; we therefore examine them further below.

Electricity cost

Unlike other energy sources such as oil and gas which have a global market, electricity is mainly local. This means that there is a huge difference between the cost of electricity across the world, as it depends on generation mix and government policy, as well as the structure of the electricity market. In some places, electricity is subject to significant taxation (such in Europe) whereas in other places it is heavily subsidized (such as in MENA). Thus, little can be said about the price of electricity at the global level.

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[15] Here, low capital costs are due to the assumed implementation of membrane-less electrolysers characterized by high 'potential for simple construction and high current densities […] driving down capital costs to the levels required for water electrolysis to compete with steam–methane reforming' (Esposito, 2017, p.651).

Nonetheless, there are some general trends in the electricity sector – such as decentralization and digitalization – that are expected to affect the cost of producing electricity worldwide.

The likely effect of decentralization on electricity production costs is evident from recent solar and wind power auctions. For example, the record low bid of 0.016 (0.01567) USD/kWh for an 800 MW Qatari solar PV facility, or Saudi Arabia's ACWA Power bid of 0.017 (0.016953) USD/kWh for the 900 MW fifth phase of the Mohammed bin Rashid Al Maktoum Solar Park in Dubai (PV Magazine, 2019 and PV Magazine, 2020) are indications of the rapid cost decline of renewables in suitable areas of the world. Such prices are three times lower than the 2019 average retail price of natural gas (0.05 USD/kWh).[16] If a reliable electricity supply at such a price is utilized for the production of green ammonia, production costs can be significantly reduced.

For illustration, let us consider the US model described in Table 4 *w*ith a three-fold decrease in the cost of energy input compared with natural gas. If such a decline in energy cost is realized, the ultimate cost of a tonne of NH_3 produced with electricity by small-scale facilities becomes comparable to a tonne produced with natural gas:

Cost of electricity (USD441 + USD67)/3 + Capital cost (USD33 + USD66) + O&M cost (USD41 + USD77) = USD386 (vs. USD339 for conventional production)

For large-scale facilities, however, electricity-based NH_3 generation, even at the same cost of energy, is less cost-competitive when compared to gas-based production:

Cost of electricity (USD441 + USD67)/3 + Capital cost (USD33 + USD32) + O&M cost (USD41 + USD13) = USD288 (vs. USD170 for conventional production).

Indeed, even with the assumption of massively low electricity prices, the cost of 288 USD/mt-NH_3 for large-scale 'green' ammonia production is less attractive than both large- and medium-scale conventional ammonia synthesis, with the respective costs being 170 and 243 USD/mt-NH_3. This, however, may not pose a significant threat for the future development of 'green' NH_3 generation projects, as technologies for small-scale ammonia production are becoming increasingly viable as the industry moves toward more sustainable and renewable feedstocks (Nitrogen+Syngas, 2018). In other words, renewable electricity may change the traditional paradigm of ammonia production facility design based on economy of scale.[17]

Capital cost

The capital expenditures incurred by investors are normally diluted with the growing scale of the ammonia generation plant, and thus the ultimate capital spending per tonne of NH_3 at large plants will be less significant than at small installations. For instance, according to Vrijenhoef (2017, p.6), for the large conventional ammonia plants in the USA, the average capital cost per tonne investment is 'in the range of 1,000–1,500 USD/tonne annual capacity installed'. In contrast, 'for the smaller plants of 4,000 tpa[18] the capital expenditure costs can be as high as 3,000 USD/tonne installed' (ibid). That is why small-scale ammonia production facilities are often viewed as less attractive for investors.

There is an argument that the production of small-scale loops disintegrated from the rest of the ammonia cycle may currently bear low economic sense. Traditionally tied to the main feedstock (natural gas) used in all the stages of NH_3 generation, conventional ammonia plants represent an integrated workshop of large-scale hardware, taking advantage of the interconnectedness of all the elements, allowing greater energy efficiency to be achieved, and economies of scale to be utilized. In most places,

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[16] Global Petrol Prices (2019b).

[17] Further research is needed to analyse the possibility and implications of the overall reduction of global electricity prices due to the fall in renewable prices.

[18] tpa – tonnes per annum

gas turbines are integrated with an ammonia process to improve energy efficiency (Sahafzadeh et al., 2013, p. 594). Therefore, if the production process is disintegrated, energy efficiency may be not be optimized. Similarly, the high costs of water electrolysis, coupled with the often low price of natural gas, makes the electrolysis-based Haber–Bosch (HB) process less economically attractive than conventional HB synthesis (Ye et al., 2017, p. 713).

The above argument is true for most conventional plants; however, this rationale does not consider the fact that small-scale ammonia production can be (and already is) organized in a 'modular' way. As hydrogen and nitrogen units are being deployed at a smaller scale, the cost of such standard units is low because the need to use integrated front-ends for small-scale ammonia plants is absent (Vrijenhoef, 2017, p. 7). Consequently, the construction expenses are minimized, as both units can, in theory, be supplied more or less off-the-shelf, delivered to the production site, and assembled as modules (ibid).

In such conditions, the main remaining fraction of capital costs is related to the Haber–Bosch (ammonia synthesis) loop, which is responsible for about 10 per cent of all the expenses (see Figure 7). Advances in this area – such as the skid-mounted ammonia loop 'with a maximum height of 12 metres' – make this piece of technology not only easily transportable but also capable of being used as one of the modules in the production cycle (Vrijenhoef, 2017). Therefore, all the elements of the ammonia production system can disintegrated with no loss of economic efficiency. Alternatively, to further minimize the capital cost or to eliminate the massive upfront capital costs altogether, all parts of the equipment can potentially be treated as a long-term lease (Ammonia Industry, 2018a).

Operations and maintenance cost

Apart from energy and capital costs, potential investors should consider the costs of operations and maintenance of green ammonia plants. Here, with respect to operations, the load factors of the NH_3 generation facilities should be taken into account as they directly influence productivity and thus the ultimate cost of the product. For instance, due to varying geographic and climatic conditions, renewable energy sources with high intermittency (such as solar and wind power) may not generate a sufficiently stable electricity supply on a continuous basis to make ammonia production economically feasible everywhere. Some studies estimate that investment in green ammonia production based on intermittent energy feedstock should be suggested in areas 'where load factors can reach up to 3,000 full load hours (FLH) for solar photovoltaics (PV) and up to 5,000 FLH for wind turbines' (Philibert, 2017, p.1). Although this potentially increases the maintenance expenses, due to the greater time in operation, the ultimate costs may be reduced, as 'high investments in electrolysers require a large onstream to minimize costs per ton' (ISPT, 2018, p.6).

When it comes to the valuation of operating costs, however, these depend, among other factors, on the combination of the exact characteristics of each specific facility and specific area of operations. As seen from Figure 7, operating costs are generally responsible for about 15 per cent of the total expenditures. In absolute terms this can be very low for small-scale facilities compared with large-scale ammonia plants. Indeed, for a small facility running on sustainable electricity averaging 0.02–0.03 USD/kWh, operating costs can be as low as around 50 USD per tonne of ammonia (Vrijenhoef, 2017, p.5). Therefore, with low capital costs for the modular deployment of ammonia facilities, this increases the economic attractiveness for investors.

5.2. Other drivers of green ammonia production

Although renewable electricity is growing fast in many regions of the world, natural gas-based ammonia production in large facilities still dominates the NH_3 market. In the absence of stable low-cost low-carbon electricity, intermittency-free ammonia plants based on hydrocarbons are likely to remain the mainstream form of production. In places where fossil fuels are cheaper than electricity, this advantage is more obvious. For example, as seen from Table 4, in the USA, the average cost of a metric tonne of NH_3 produced at small-scale conventional plants (339 USD/mt-NH_3) is USD386 (53.2 per cent) cheaper than a metric tonne of ammonia generated in a small-scale electric plant (725 USD/mt-NH_3). Not surprisingly, for large-scale facilities, this difference (USD457 or 72.9 per cent) is even more significant. Similarly, the average gap between electricity- and gas-based ammonia in Europe is 300 EUR/mt-NH_3 (ISPT, 2018).

In such circumstances, successful 'green' ammonia production is economically feasible if there are policies that restrict emissions or internalize the cost of externalities. In other words, the cost gap between a metric tonne of conventionally-produced ammonia and a metric tonne of 'green' ammonia could be narrowed or eliminated through appropriate policies.

With legislative pledges to achieve net zero carbon by the end of the first half of this century, many progressive governments have already imposed some forms of carbon pricing either in the form of tax or tradeable emission certificates. The use of cap-and-trade schemes is becoming particularly popular. However, since the market price for CO_2 allowances may not necessarily reflect the real social cost of emissions, imposing carbon taxes with emission limits on heavy polluters could potentially stimulate 'green' ammonia businesses more effectively than allowing them to sell the certificates to potentially wealthier large-scale conventional NH_3 producers. Alternatively, governments can introduce a minimum price for tradeable emission certificates that will allow small 'green' ammonia and other businesses to compete with larger conventional producers through levelling their costs of production. Just as in the case of emission restrictions and carbon taxes, this will require a thorough economic analysis as well as a specific legislative initiative in each particular country.

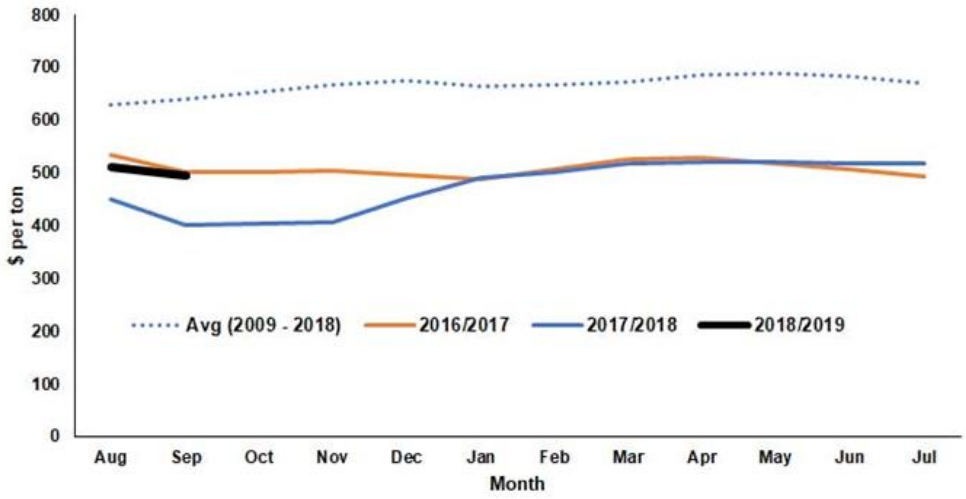
There is also the possibility of offering incentives to green ammonia producers. Various incentives (such as subsidies or tax breaks) could be used as an alternative, or to complement, carbon pricing in order to narrow the cost gap between conventional and 'green' ammonia; this could also create favourable conditions for the sustainable operation of such businesses in the future. Specifically, apart from the subsidies to renewable energy producers that already exist in many countries of the world, governments could subsidize decarbonized hydrogen generation. Since renewable energy generation and ammonia synthesis are, in contrast to the production of 'green' hydrogen, already quite well-developed, incentivizing H_2 production will help this part of the ammonia cycle to be brought 'to scale' (Hydrogen Council, 2020, p. vi). The claim is that, globally, 'achieving competitive renewable hydrogen from electrolysis requires the deployment of aggregated 70 GW of electolyser capacity' (ibid). Thus, by providing incentives for 'green' hydrogen producers in the form of subsidies or tax breaks, governments could make such businesses more competitive and scale up the production.

5.3. Green ammonia revenue generation

As mentioned previously, small-scale NH_3 generation based on renewables produced in favourable geographical conditions (such as solar power in the Middle East region) could potentially result in the cost of a metric tonne of 'green' ammonia being as low as USD386. In these circumstances, depending on the specific cost components and government policies in each case, the revenue of 'green' NH_3 producers will vary. For example, if no other expenditures are incurred, in the case that the price of a metric tonne of ammonia remains at the 2009–2018 average decade level (see Figure 8), the revenue of low-cost green ammonia producers could theoretically be in the range of 234–294 USD/mt-NH_3 (*620–680 USD/mt-*NH_3 *– 386 USD/mt-*NH_3 *= 234–294 USD/mt-*NH_3).

At the same time, due to the oil price shocks of early 2020, the price of anhydrous ammonia in spring this year fell to its lowest level in a decade (Successful Farming, 2020). Specifically, according to ICIS (2020), the average monthly contract prices in April 2020 were around 215–250 USD/mt, which is lower than the minimum production cost of sustainable ammonia by more than USD100. This makes green NH_3 generation at USD386 uncompetitive on a global fertilizer market where 'conventional' ammonia producers would have competitive advantage due to the currently low feedstock prices.

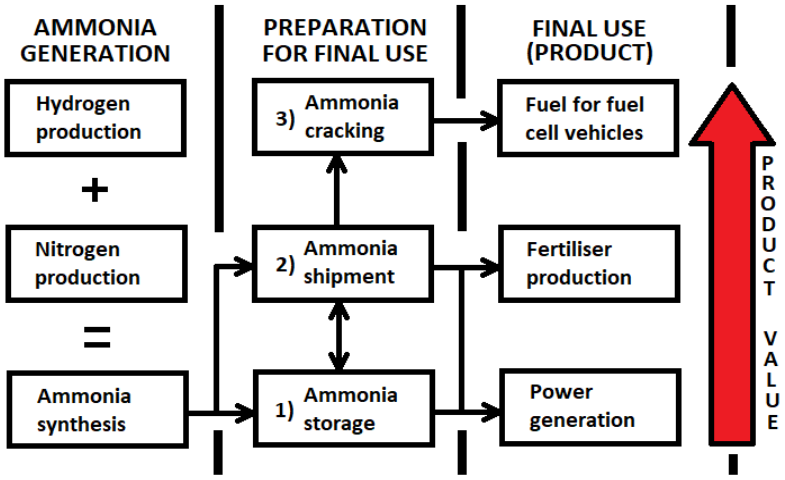
Figure 8: Anhydrous ammonia prices by month from 2009 to 2018 (USD/mt-NH_3)



Source: US Department of Agriculture (2019)

On the other hand, as mentioned in previous sections, while being primarily used as a feedstock for the production of fertilizers, pure ammonia can also be combusted in gas turbines for subsequent power generation, used in ammonia fuel cells, or decomposed to extract hydrogen that is later used for hydrogen fuel cell-based propulsion.[19] Although the former process currently does not appear to be attractive due to ammonia's very low combustion efficiency, the latter is argued to be a more efficient use of ammonia (Kobayashi et al., 2019, pp. 112). Specifically, utilizing NH_3 as a hydrogen carrier would mean taking advantage of the higher product value of this chemical substance, which is likely to result in higher price levels for the final product, as well as potentially greater revenue generation by 'green' ammonia companies (Wilkinson, 2017) (see Figure 9).

Figure 9: Ammonia production pathway



Source: Adaptation from Wilkinson (2017)

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[19] NH_3 decomposition (cracking) represents the reverse of the synthesis reaction:
$NH_3 (g) \rightarrow 1/2\ N_2 (g) + 3/2\ H_2 (g)$

As shown in Figure 9, in the case that NH_3 is used as hydrogen carrier, apart from the direct production costs, ‘green’ ammonia’s pathway to the final customer is associated with three additional sets of expenditures: (1) storage, (2) transportation (shipment), and (3) cracking. Although further technological development, and progress in the overall transition to a net zero economy, could mean that all these costs are likely to be occupied by niche companies, small-scale ‘green’ NH_3 enthusiasts may have to cover them by themselves, in order to deliver the product to the target destination. That is why it seems reasonable to estimate whether such a journey of ‘green’ ammonia as a means of carrying hydrogen makes economic sense, in comparison to the direct delivery of hydrogen to the final consumer (for example fuel cell vehicle owners). In this connection, such a comparison should encompass the ultimate cumulative costs after all the relevant post-generation stages. Here, for ‘green’ ammonia, apart from direct spending on NH_3 synthesis (0), it will include all the three described phases (storage (1), transportation (2), and cracking (3)), whereas for ‘green’ hydrogen it will exclude the final phase (decomposition) – leaving H_2 synthesis (0), storage (1), and shipping (2) (see Table 5).

Table 5: Approximate storage, transportation, and decomposition costs (best case)

#	**Cost type**			**Ammonia**	**Hydrogen**		
0	**Production costs (USD/mt)**			*386*	221		
1	**Storage costs (USD/mt)**	**Storage form**		**Compressed**			**Liquefied**
		Tanks		~120–180	~145–234		~820–1,990
		Salt caverns			~101–165		
A	Minimal cumulative costs: production + transportable storage (USD/mt)			~506–566	~366–455		*~1,041–2,211*
2	**Transportation costs (USD/mt-km[20])**	**Indicative distance (km)**		**Atmospheric air pressure (bar)**	***350***	***430***	***n/a***
		Road (truck)	<1,000	~0.21	*~1.88*	~1.47	~0.58
		Rail	~800–4,000	~0.025	~0.39	~0.35	~0.18
		Shipping	>4,000	~0.019	~0.37	~0.33	~0.057
B	Minimal cumulative costs: production + transportable storage + transport (USD/mt per 1000 km)			~531–591	~736–825	~696–785	*~1,098–2,268*
C	Minimal cumulative costs: production + transportable storage + transport (USD/mt per 2000 km)			~556–616	~1,106–1,195	~1,026–1,115	*1,278–2,448*
3	**Decomposition (cracking) costs (USD/mt-H_2)**			~241–343	n/a		
D	Minimal cumulative costs (ammonia): production + transportable storage + transport (1000 km) + decomposition			~773–934			
E	Minimal cumulative costs (ammonia): production + transportable storage + transport (2000 km) + decomposition			~797–959			

Source: Adaptation from ARENA (2018), CSIRO (2018), Boddula and Asiri (2020), Royal Society (2020)

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[20] mt-km (metric tonne-kilometre) – the transportation of one metric tonne of hydrogen/ammonia by a given transport mode over a distance of one kilometre.

- **Production costs (0)**

In Table 5, at the initial stage indicating expenses related to ammonia and hydrogen synthesis (section 0), the approximate cost of 'green' NH_3 is estimated in compliance with the model described in Section 5.1 where the cost of electricity is assumed to be around 0.016 USD/kWh (namely three times lower than the estimated cost of 'green' ammonia production for average electricity-powered projects in the USA) (described in Table 4). Following this assumption, the costs of 'green' ammonia production at a small-scale electricity-based facility is calculated to be around USD386/mt. As H_2 generation represent the first stage in the process of ammonia production, for the same facility the cost of hydrogen production could be calculated as follows:

Cost of electricity (USD441)/3 + Capital cost (USD33) + O&M cost (USD41) = USD221/mt

- **Storage costs (1)**

Traditionally, for the long-term preservation of large amounts of hydrogen and ammonia, '*low-temperature* storage is used based on cost considerations' (Bartels, 2008, p.63). At the same time, apart from low temperature, *high pressure* is normally applied to enable the storage of both substances in either compressed or liquefied form in specialized tanks or (salt) caverns (ibid). Here, though, underground storage of ammonia in salt caverns is often not considered, due to the challenges associated with its high toxicity (Bartels, 2008), Keeping hydrogen in underground salt caverns, however, is a technically feasible option, despite the fact that most globally generated H_2 is currently stored in tanks as a compressed gas or cryogenic liquid (US Department of Energy, 2020).

Indeed, at the moment, underground hydrogen storage in salt caverns is represented by only a handful of projects in the UK and USA, which is primarily due to the fact that most of the suitable underground storage facilities are exploited for the preservation of natural gas – a more popular fuel in the current energy paradigm (Caglayan et al., 2020). Here, economic reasons play a key role, because a H_2 cavern contains around four times less energy than an equivalent cavern storing natural gas (Stonergy, 2019).

Nonetheless, the idea of keeping H_2 in salt caverns could potentially gain more popularity in the future. This is because, due to its low volumetric energy density, 'high-pressure tanks of sufficient size that store enough hydrogen (as a gas) to be useful to energy systems on a nation scale are simply impractical' (Energy Post, 2020). Furthermore, hydrogen preservation in vessels is subject to H_2's permeability challenge (Nemanic, 2019).[21] Instead, if geological conditions allow, substantial amounts of pressurized H_2 can be preserved underground (at 45–150 bar) (Stonergy, 2019). The downside, however, is that the global potential of underground hydrogen storage is geographically restricted, due to its transportability limitations.

When it comes to storing these substances in a deliverable form, keeping compressed ammonia in a transportable vessel (tank) is cheaper than preserving either compressed or liquefied hydrogen in a tank (*120–180 USD/mt for compressed NH_3* ***vs.*** *145–234 USD/mt for compressed H_2 or 820–1,990 USD/mt for liquefied H_2*).

At this point, however, despite the fact that transportable storage of ammonia is cheaper than transportable storage of hydrogen, the cumulative expenditures (generation + transportable storage) would still be lower for hydrogen (*~506–566 USD/mt-H_2 for NH_3* ***vs***. *~ 366–455 USD/mt for H_2*,due to the lower initial production expenses of H_2 (see *section A* in *Table 5*). On the other hand, if investors also include capital costs, the odds will be on 'green' ammonia's side again. Indeed, according to Bartels

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[21] Hydrogen permeates through many non-metallic materials in the molecular (namely diatomic) form; as atomic hydrogen, it can permeate through structural metals (Walker, 2008).

(2008, p. 70), ‘ammonia storage facility capital cost is nearly 25 times less than that of hydrogen per unit of stored energy’.

- **Transportation and decomposition costs (2 and 3)**

As seen from section 2 in Table 5, delivering ammonia is significantly cheaper than delivering hydrogen by all traditional transport modes. Here, in addition to representing the mode with the shortest indicative operating range, road transport (truck) appears to be the most expensive option for both ammonia and hydrogen. In contrast, transportation of both substances for extremely long distances (over 4,000 km) is economically most attractive if conducted by maritime transport, when compared to rail and road. At this stage, the minimal cumulative costs calculated per 1,000 km (in other words, production + transportable storage + transportation) indicate that ammonia is already cheaper than the next-cheapest variant – that is hydrogen compressed at 430 bar:

For ammonia:

Production cost (386 USD/mt) + Transportable storage cost (120–180 USD/mt) + Minimal transportation cost
(19 USD/mt per 1000 km) = 531–591 USD/mt per 1000 km

For hydrogen:

Production cost (221 USD/mt) + Transportable storage cost (145–234 USD/mt) + Minimal transportation cost
(330 USD/mt per 1000 km) = 696–785 USD/mt per 1000 km

Although at this point it seems clear that the delivery of hydrogen over long distances is more expensive than similar transportation of ammonia, the cost of decomposition of NH_3 should be added to obtain a clear picture of the competitiveness of ammonia as a H_2 carrier:

Pre-cracking cost (532–591 USD/mt per 1000 km) + Cracking cost (241–343 USD/mt-H_2) = 772-934 USD/mt-H_2 per 1000 km (see part 3 and sections B and D in Table 5).

As seen, although the costs happen to be close to those incurred in the case of hydrogen delivery, transporting such ‘green’ NH_3 a distance of 1,000 km for the purpose of delivering H_2 is still slightly more expensive than transporting pure H_2 (*~772–936 USD/mt-H_2 per 1000 km for NH_3* ***vs.*** *~ 696–785 USD/mt-H_2 per 1000 km for H_2* (see *sections B and D* in *Table 5*)

On the other hand, in the case that ammonia’s delivery distance rises to 2,000 km, it already appears to be significantly cheaper than hydrogen (*~797–959 USD/mt-H_2 per 2000 km for NH_3* ***vs.*** *~1,026–1,115 USD/mt-H_2 per 2000 for H_2*) (see *sections C and E* in *Table 5*).

Apart from road, rail, and maritime transportation, ammonia can also be delivered through pipelines. In fact, in some regions of the world, long-distance ammonia delivery is typically conducted through pipelines as they represent a more economical transport method (Appl, 1999). In the USA, for example, cost considerations spurred the development of an extensive network of NH_3 pipelines, the total length of which had already exceeded 4,800 km more than a decade ago (Bartels, 2008). In contrast, despite the extensive use of hydrogen in US industry, only 719 km of H_2 pipelines had been constructed in the same timeframe; this could potentially indicate a significantly lower interest in this mode of hydrogen delivery (ibid). One of the reasons for such low popularity of this transport mode could be the problem of hydrogen embrittlement, which affects steel pipelines. To combat this issue, a different type of steel[22]

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[22] Ammonia pipelines use carbon steel; hydrogen pipelines should be made from steel with yield strength of 689 megapascals (MPa) rather than from high-strength steels (Argonne National Laboratory, 2007).

is required for H_2 pipelines and additional testing is needed before high-pressure hydrogen pipelines are used on a large scale (Argonne National Laboratory, 2007).

The ammonia pipeline system also has a higher efficiency than the hydrogen pipeline system (93.4 per cent against 86.9 per cent, respectively) (Bartels, 2008, p. 95). In addition, due to the special structure of the ammonia molecule (namely, having one nitrogen atom and three hydrogen atoms), the NH_3 pipeline is able to carry 'nearly twice the energy for an assumed pipe diameter' when compared to the H_2 pipeline (ibid). As a result, the cost estimations of Bartels demonstrate that for the long-distance transportation of energy (here, over 1,610 km) ammonia pipeline infrastructure appears to be cheaper than the equivalent for hydrogen (ibid). Furthermore, 'as the transmission distance increases, the cost of transporting hydrogen by pipeline escalates faster than the cost for ammonia since a greater number of compressor stations are required' (IEA, 2019c, p. 78). Following this principle, 'if the transmission distance is 2,500 km the cost of transporting ammonia by pipeline, including the conversion cost, becomes broadly similar to the cost of transporting hydrogen as a gas' (ibid). Hence, for the purpose of carrying and delivering hydrogen over long distances on land, ammonia appears to be economically more attractive than either compressed or liquefied pure hydrogen.

Overall, it could be concluded that, despite possessing a higher initial cost of production, ammonia could potentially represent an economically feasible option for delivering 'green' hydrogen over long distances, as well for preserving it in a transportable form for a long time. In fact, according to the Royal Society (2020, p. 24), out of all the energy storage options not based on fossil fuels, 'ammonia is the lowest-cost method and the most technologically-ready option for transporting energy over long distances'. That is why, despite the currently less attractive technological and market conditions facing green ammonia producers in generating revenue from ammonia synthesis for its direct combustion or further use as a fertilizer, it seems that there is an economically efficient alternative – in other words, that of producing ammonia for the purpose of preserving hydrogen.

6. Summary and Conclusions

Storing large volumes of energy for prolonged periods of time in a transportable form can significantly assist decarbonized energy and power systems. Specifically, apart from offering the possibility for connecting energy sources with consumers, periodic and seasonal transportable storage can balance the energy system at times when climatic conditions are unfavourable. This could allow for a more efficient utilization of renewables in the energy system and facilitate the decarbonization of the entire energy sector.

Out of all the currently available types of energy storage solutions, only some electrochemical, mechanical, and chemical options allow for the preservation of energy for periods exceeding weeks and months. Despite possessing impressive volume and duration characteristics, mechanical energy storage solutions (such as pumped hydro and compressed air) are less attractive than electrochemical (li-ion and flow batteries) or chemical storage (natural gas, hydrogen, and ammonia) when transportation of stored energy is needed. On the other hand, at the current stage of technological development, transportable batteries with significantly lower storage duration appear to be substantially less advantageous than most of the chemical options in terms of storage capacity, energy density, as well as deployment costs. That is why chemical storage options represent a promising solution for the long-term large-scale preservation of energy in a transportable form.

Natural gas, hydrogen, and ammonia are notable candidates among chemical energy storage solutions. Natural gas has a number of advantages over hydrogen and ammonia, but it has a serious drawback as it is a fossil fuel. Unlike natural gas, hydrogen and ammonia could potentially be generated carbon-free. Hydrogen has a lower volumetric energy and higher vapour pressure than ammonia. These characteristics create additional difficulties for its preservation and transportation, by making its handling more complicated, expensive, and less safe. On the contrary, despite representing a toxic substance whose 'green' production technology is not fully established or scaled, ammonia is a relatively rapidly deployable and easy-to-handle substance that does not produce any carbon emissions in the case of direct combustion of if used for ammonia or hydrogen fuel cell. As a result, for a decarbonized scenario, ammonia, if produced in a green way, is a promising substance for storing transportable energy in large volumes and for a long period of time.

Ammonia best fits in the energy system as an energy vector of hydrogen. Additionally, as a hydrogen carrier, ammonia represents a more economical way of delivering hydrogen over long distances than the conventional way of transporting hydrogen in compressed or liquefied forms. In this sense, green ammonia producers could also benefit from the integration of their product into the hydrogen energy economy of the future. Apart from the intra-sectoral alignment of different elements of the energy industry across territories and geographic areas, spreading the use of ammonia as a means of long-term large-scale energy storage could allow for cross-sectoral integration, which would offer new benefits to other sectors (such as transport).

Despite the unique features of ammonia, its use in the energy system has been very limited. Indeed, about 80 per cent of the global use of ammonia is related to the fertilizer industry and only less than 1 per cent is utilized for energy-related purposes. Thus, the integration of ammonia into the energy system offers a broad space for further improvement. However, the conventional method of producing ammonia, based on fossil fuels, is an impediment to its growth in the energy system. Specifically, in most cases, at the first stage of the ammonia production process (utilizing natural gas to produce hydrogen through steam–methane reforming) is cheaper than using electrolysis. The second phase (nitrogen production via air separation or pressure swing adsorption) incurs similar costs for both feedstocks (natural gas and electricity). The final stage of ammonia generation (based on the Haber–Bosch process or electrolytic/electrochemical synthesis) again puts the odds in favour of natural gas, due to the low overall prices of this fuel and maturity of the technology.

Nevertheless, a set of endogenous and exogenous factors can tip the balance in ‘green’ ammonia’s favour. In particular, in places where climatic conditions allow for ultra-low-cost green electricity (such as that produced from wind or solar PV installations), small-scale ammonia synthesis can compete with conventional ammonia facilities of the same scale. This is currently limited to specific places, but with further technological progress, the production of ‘green’ ammonia by small-scale facilities could become well-spread internationally. Also, the possibility of decentralized ammonia production through distributed generation would lower transportation costs and thus potentially offer a cheaper product.

There are other factors that could facilitate the development of the green ammonia industry in the future. Specifically, apart from the likely growth in global demand for ammonia, government incentives for decarbonization (through introducing emission restrictions, carbon taxes, subsidies, or tax breaks for investors) can boost green ammonia production.

In sum, ammonia represents a promising solution for the dilemma of long-term large-scale energy storage. As such, with the potential to integrate different elements of the energy system, it could become a decisive element in the global effort to reduce carbon emissions and enhance overall decarbonization strategies. However, at the current stage of technological development, green ammonia production appears to be economically efficient only if conducted on a small-scale basis in specific geographic regions, where weather and climate conditions favour ultra-low-cost electricity generation. Therefore, there is a need for policy and regulatory support to encourage large-scale deployment of this storage solution. Furthermore, the rules around energy storage, as well as its very definition, need to be updated and clarified so that innovation and deployment of green ammonia technology are stimulated and barriers to its growth are lifted.

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