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REVIEW PAPER

The present condition and outlook for hydrogen-natural gas blending technology

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Abstract−Korea's economy should develop a safe and cost-effective hydrogen transport system to realize the hydrogen economy. Among the methods of hydrogen transport, pipelines are the only feasible means of achieving cost-effective and safe transport over longer distances. This technical report proposes a method that would allow for using existing natural gas pipelines to transport mixed gas (hydrogen-natural gas). The properties of the mixed gas, the durability of the pipeline caused by hydrogen embrittlement, and gas loss from leakage are reviewed according to the hydrogen ratio. In addition, several separation methods of mixed gas are introduced. From the survey of international research or pilot projects, if hydrogen is blended with a concentration less than 20%, that does not significantly affect gas quality, safety, risk, materials, and network capacity. This study also suggests the suitable hydrogen supply methods for domestic use.

Keywords: Hydrogen, Blending Ratio, Pipeline, Embrittlement, Leakage

INTRODUCTION

Major economies, including those of Europe, China, and Japan, have announced their intentions of running carbon-neutral goals by 2050, and are now investing in the development of hydrogen-based solutions to climate change. According to the International Energy Agency, the world consumed approximately 70 million tons of hydrogen in 2020, and demand is expected to steadily increase through 2050 (Fig. 1) [1]. In January 2019 Korea established the "Hydrogen Economy Revitalization Roadmap" that incorporates plans to reduce hydrogen production and transportation costs and ensure an adequate supply by 2040, and is seeking strategies to lower hydrogen production and transportation costs to secure supply according to hydrogen demand [2].

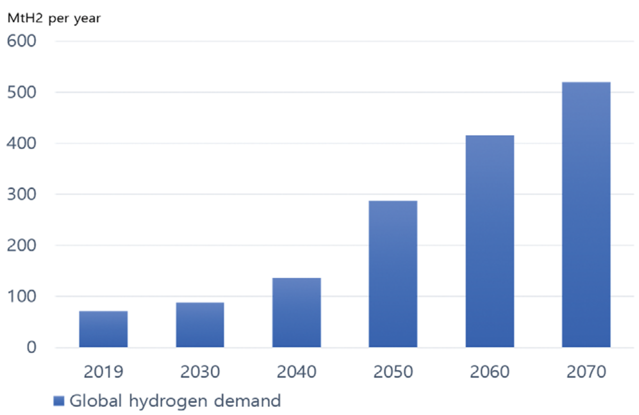

Fig. 1. Predicted global hydrogen demand (Modified) [1].

Hydrogen production methods fall into one of three categories. Grey hydrogen is produced via steam methane reforming (SMR) of fossil fuels such as oil, gas, and coal. Blue hydrogen incorporates a Carbon Capture & Storage (CCS) process that traps the CO_2 generated during the SMR. Green hydrogen is produced using electricity generated by renewable energy [3].

Of these, green hydrogen is the most eco-friendly, as it relies on abundant and renewable raw materials and only produces O_2 as a by-product. While a number of electrolysis methods exist, including those relying on proton exchange membrane (PEM), alkaline, and solid oxide electrolyte (SOEC), their high initial investment costs and significant power consumption renders them uneconom-

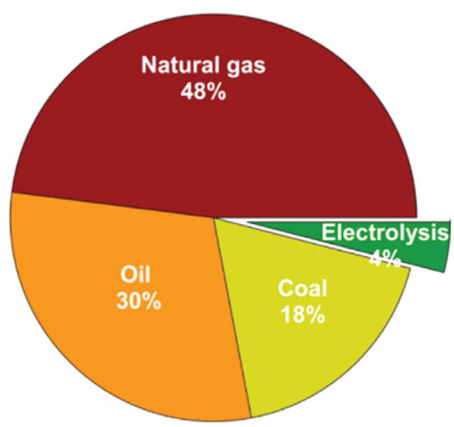

Fig. 2. Worldwide hydrogen production by sources [4].

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Table 1. Hydrogen supply plan *Unit: 1,000 ton [3]

Type	2020		2022		2030		2040	
	Quantity	%	Quantity	%	Quantity	%	Quantity	%
Byproduct (Factory)	130	100	280	60	280	14	280	5
Extraction (LNG)	-	0	170	36	970	50	1,580	30
Electrolysis (Water)	-	0	20	4	140	7	680	13
Overseas (Blue)	-	0	-	0	550	28	2,720	52
Total	130	100	470	100	1,940	100	5,260	100

ical and unfit for mass adoption [4-6]. Accordingly, 95% of current hydrogen is produced through grey and blue hydrogen methods using SMR [7]. Natural gas, which is easy to transport and produces the lowest CO_2 emissions, is widely employed as a feedstock of the SMR-based hydrogen production process (Fig. 2) [2,5,8,9].

The hydrogen generated as a by-product from the production of petrochemical products and grey hydrogen produced through SMR are both important components of domestic supply. Although by-product hydrogen is inexpensive, there is a limit to the expansion of production. SMR emits 8 to 10 kg of CO_2 per 1 kg of hydrogen produced, although the efficacy and cost effectiveness of the process has prompted its wide adoption in Europe and Japan. According to Korea's hydrogen supply plan, SMR is expected to account for the largest amount at 30%, excluding overseas imports in 2040 (Table 1) [3].

One significant barrier that has impeded a more widespread transition to the hydrogen economy has been the lack of a reliable and cost-effective hydrogen transport system [10]. Hydrogen supply and demand chains are classified as either off-site or on-site, on the basis of the supply and demand locations and production volume. Off-site facilities produce hydrogen at a large-scale intermediate hydrogen production base, and the produced hydrogen is transported to fueling stations by trucks or pipelines [8]. It is possible to produce 750,000 kg/day of hydrogen at these facilities [11,12]. While efficient, these facilities impose high initial capital costs and the existence of an efficient transportation infrastructure [13]. On-site facilities produce hydrogen voluntarily at local factories or fueling stations. The process is less efficient but has a lower loss rate during transportation [14,15]. Currently, off-site production methods predominate, only a little hydrogen is produced at local fueling stations [16]. At this point, a standard is being developed to supply hydrogen to the fueling station using an off-site method after producing a large amount of hydrogen by SMR [13]. Therefore, a transportation infrastructure that can stably supply a large amount of hydrogen is required and is classified into trucking and pipeline transport taking into account geographic characteristics, population density, demand, road conditions, and infrastructure characteristics.

Trucking is one method of transporting hydrogen, and available methods are classified based on the state of the transported hydrogen. Gas-type compressed hydrogen is transported in a tube trailer equipped with a high-pressure storage container on a special vehicle to a hydrogen fueling station [17]. These containers allow for stable and direct storage and transport of high-purity hydrogen. This method, however, requires high-pressure compression compared

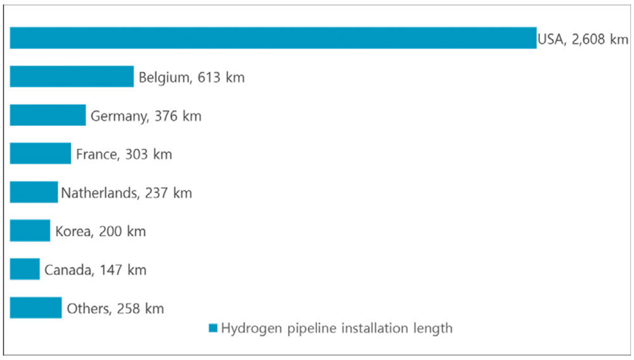

Fig. 3. Hydrogen pipelines installed (Modified) [21,23].

to natural gas compressions, additional costs are incurred, which raises the overall costs [18]. Moreover, according to the hydrogen tube trailer regulations set forth by the US Department of Transportation (DOT), the hydrogen compression pressure per unit cannot exceed 25 MPa, and trucks may only transport 800 kg per trailer [8,19]. While this is significantly less than the amount that can be transported through liquefied hydrogen trucking and pipelines [10, 18], compressed hydrogen trucking may still be efficient where alternative means of transport do not exist for distances below 200 km.

Pipelines are the most inexpensive and efficient means for the long-distance, large-scale transportation of hydrogen with minimal energy loss [10,20]. Over the medium-term, pipelines cost significantly less than trucking, and are particularly efficient in areas with a population high enough to sustain hydrogen demand [10]. As of 2016, more than 4,500 km of hydrogen pipelines had been installed around the world (Fig. 3) [21,22], significantly less than the total number of natural gas pipelines. In Korea, approximately 200 km of hydrogen pipelines have been installed in petrochemical facilities located in Ulsan, Yeosu, and Daesan [23].

The initial capital costs associated with hydrogen pipeline installation are material costs, labor costs, and right-of-way costs [24,25]. Some typical pipeline materials like steel, however, may be ill-suited for hydrogen pipelines, as embrittlement can occur when they are exposed to a high concentration and high-pressure hydrogen over an extended period. The risk of hydrogen embrittlement necessitates the use of expensive materials [26,27], and depending on the pipeline diameter and operating pressure, material costs can run 68% higher than if steel were used [28]. There is a risk of leakage due to hydrogen embrittlement, which requires additional maintenance costs for replacement of the pipe. Moreover, the cost of obtaining the right of way (ROW) access increases up to seven times depending on the installation location [19]. In short, hydrogen pipelines are not only more costly, but also more time-consuming to construct than natural gas pipelines [27,28].

With this in mind, some have proposed a new method that would allow for the use of existing natural gas pipelines to transport hydrogen. Excluding local pipelines, in Korea there are 4,945 km of available pipes [29], while in the United States a network of 482,803 km onshore natural gas pipelines exists [30]. If this method were to be widely adopted, the cost of new infrastructure would be dramatically reduced in contrast to hydrogen pipelines.

The EIA in its 2021 Annual Energy Report predicts that the supply & demand for natural gas will steadily increase until 2050, and that pipelines will be used more actively to supply natural gas [31]. Several studies have already proposed the viability of blending hydrogen and supplying each to appropriate local networks in a low-cost, high-efficiency manner [32-34]. The materials and specifications of pipelines differ across countries, necessitating an examination of the appropriate blending ratio for each individual supply chain. As any leaks may harm humans and damage property, safety evaluations must be conducted of the entire supply infrastructure, including pipelines [32,35]. In anticipation of further efforts to secure a stable hydrogen supply infrastructure in Korea, we assess the feasibility of hydrogen-natural gas blending in consideration of changing characteristics and possible hydrogen embrittlement. In addition, by introducing overseas cases related to hydrogen blending technology carried out in various countries, this study would like to suggest a hydrogen supply method suitable for domestic use.

HYDROGEN · NATURAL GAS BLENDING

The creation of blended gas supplies can be achieved in different ways according to hydrogen production type, supply, and demand chain. In the on-site method, natural gas, which is used as the feedstock for hydrogen production, is directly transported to a fueling station where hydrogen is produced. In the off-site method, hydrogen produced by SMR or water electrolysis at hydrogen production base can be blended with natural gas and transported through existing pipelines to hydrogen fueling station. Hydrogen and natural gas are separated and purified at intermediate destinations, and then extracted hydrogen can be distributed to consumers via the local transportation network (Fig. 4) [2]. The implementation of this blending technology will require careful consideration of the hydrogen separation and purification processes, as well as any leakage problems that may arise as a result of hydrogen embrittlement as mixed gas is pumped through the pipelines. Alternatively, in the case of a gas mixture consisting of 10-30% hydrogen and 70-90% methane (hythane) can be used for fuel and household gas appliances without separation and purification processes. The use of hythane gas is validated through projects in several countries.

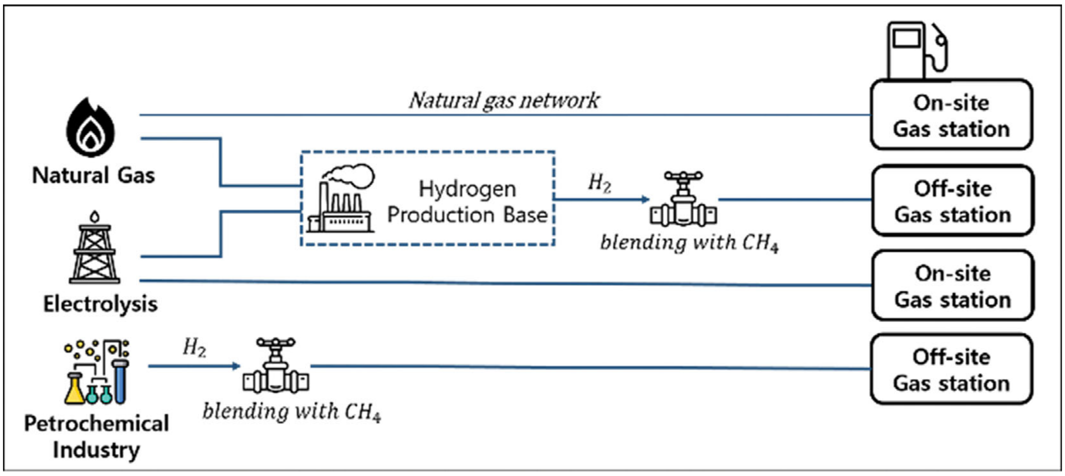

Fig. 4. Hydrogen-natural gas blending processes.

Table 2. Hydrogen/methane compared (Modified) [32]

Properties	Hydrogen	Methane	Unit
Vapor density (at T=293.15 K and P=1 bar)	1.34	1.82	kg/m^3
Dilute gas viscosity (at T=299 K)	9×10^{-6}	11×10^{-6}	Pa·s
Solubility in water	0.0016	0.025	kg/m^3
Specific heat capacity (at T=293.15 K and P=constant)	14.4	2.21	kJ/kg/K
Molecular diffusivity in air	6.1×10^{-5}	1.6×10^{-5}	m^2/s
Auto ignition temperature	585	540	°C
Explosive limits	18.2-58.9	5.7-14	Vol % in air
Flammability limits	4.1-74	5.3-15	Vol % in air

1. Hydrogen · Natural Gas Blending

Hydrogen's physical and chemical properties are markedly different than those of natural gas. Methane is denser and has a higher volume, viscosity, and water solubility than hydrogen. In contrast, hydrogen has higher specific heat capacity, molecular diffusivity, auto-ignition temperature, and explosion and fire risks than methane (Table 2) [32,36]. Accounting for these characteristics of hydrogen, its addition to a natural gas network may increase the risk of fire and explosion as a consequence of ignition and leakage [37]. When mixed gas is transported along an existing natural gas pipeline, an appropriate blending ratio that does not impair the safety and integrity profile of the existing pipeline must be selected.

When the composition of the transported natural gas is changed through the addition of hydrogen, the Wobbe index, flame speed, HHV, specific gravity, and explosion or flammability limit are altered.

1-1. Wobbe (W) Index

The Wobbe index (W), which represents the exchange capacity of different fuel gases, is used to determine how changes in gas quality affect pipeline capacity [38]. A high Wobbe index value suggests overheating or the presence of a significant amount of carbon monoxide, while a too-low value suggests a risk of flame instability or backfire [39]. Accordingly, an acceptable range is specified as an important combustion parameter in gas appliances [40]. When 10% concentration of hydrogen is mixed with natural gas results in a Wobbe index decrease of approximately 2% from baseline (pure natural gas). According to Korean regulations, which are designated from 54.0 MJ/Nm^3 to 56.1 MJ/Nm^3, this reduction is insignificant.

1-2. Flame Speed

Flame speed is a combustion parameter related to backfire and flame stability, which are risks particular to confined areas, affecting the ignition of gases related to gas appliance flame safety. According to Altfeld and Pinchbeck [41], laminar flame speed increases with the ratio of hydrogen. A 10% hydrogen mixture results in an increase in flame speed of approximately 5-10% (Fig. 5) [41].

1-3. Higher Heating Value (HHV)

Higher heating value (HHV) refers to energy content per unit volume of gas as it is completely burned in the air. The HHVs of methane and hydrogen are 38.3 MJ/m^3 and 12.1 MJ/m^3, respectively.

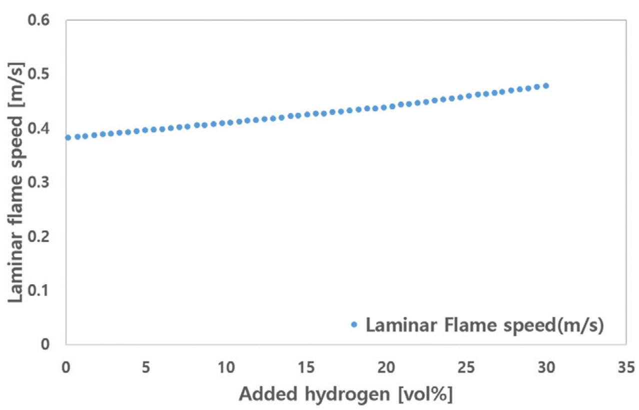

Fig. 5. The relationship between laminar flame speed data and blending ratio (Modified) [41].

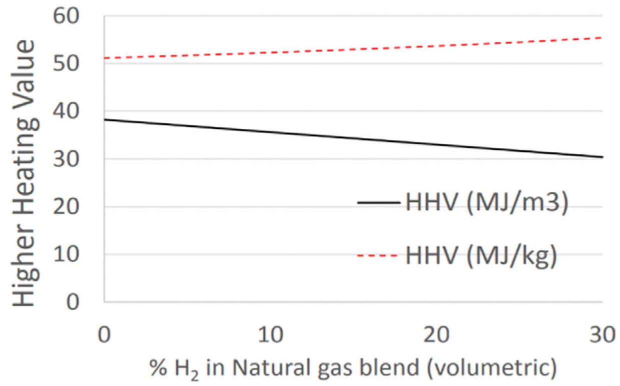

Fig. 6. The relationship between HHV and blending ratio [39].

When the concentration of hydrogen in a methane mixture reaches 10%, the HHV becomes 35.1 MJ/m^3, which is slightly lower than that of pure methane (Fig. 6) [39,42]. As the HHV is reduced when hydrogen is added, there may be a loss of efficiency in, for example, downstream reciprocating engines and gas turbines. A lower HHV requires a higher total volumetric flow rate for equivalent energy transfer, necessitating the addition to or modification of infrastructure with valves, meters, and changes to pipe diameter.

1-4. Specific Gravity

Specific gravity, also referred to as relative density, is the ratio of

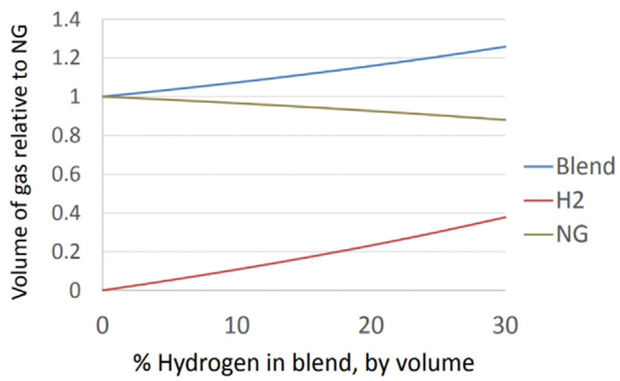

Fig. 7. The equivalent energy content of hydrogen/natural gas mixture [39].

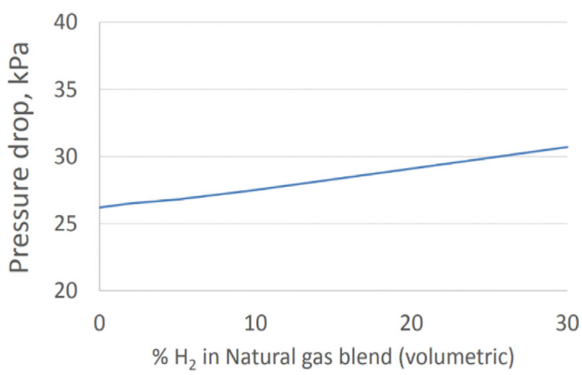

Fig. 8. The relationship between pressure drop and blending ratio [39].

Table 3. The relationship between explosion/flammability range and blending ratio (Modified) [43]

H_2 mixed ratio (%)	0	20	40	60	80	100
Lower Explosive/Flammable Limit	5.0	4.6	4.4	4.4	4.6	5.0
Upper Explosive/Flammable Limit	16.0	19.9	26.0	33.5	47.6	76.5

the density of the gas mixture to the air density. This parameter is important for measuring gas flow. The volume energy density of methane is approximately three times that of hydrogen, 39 MJ/m^3 and 12 MJ/m^3, respectively [42]. When hydrogen forms 30% of a mixture, 1.26 m^3 of the mixed gas (hydrogen-0.38 m^3, natural gas-0.88 m^3) volume is required to deliver the same amount of energy as 1 m^3 of pure natural gas (Fig. 7). In short, total volumetric flow increases along with hydrogen concentration, as gas velocity and pressure drop in the pipeline. For example, if a mixture that includes 30% hydrogen is mixed in a 100 m long 25 mm diameter pipeline operated at an inlet pressure of 40 kPa, there will be 12.5% more pressure loss than a scenario involving no hydrogen (Fig. 8) [39,40].

1-5. Explosive/Flammable Limit

Changes to the concentration of vapor or gas present in the air result in new lower explosion limits (LELs) (the point at which gas explosion occurs) and upper explosion limits (UELs) (the point at which flame does not spread). The LEL and UEL of pure methane are 5.0% and 16.0%, while the LEL and UEL of pure hydrogen are 5.0% and 76.5%. In a methane mixture comprised of 10% hydrogen, LEL and UEL are approximately 4.6% and 19.9%. As the concentration of hydrogen in the blend increases, the explosive range expands (Table 3) [43].

Hydrogen concentration also affects pipeline fatigue life. In cases where the pipeline pressure of an X80 grade pipeline falls between 1.2 MPa to 12 MPa three times a month, fatigue life is significantly reduced. A 20% concentration of hydrogen reduces pipeline fatigue life by as much as 94% (Table 4). Thus, as the amount of hydrogen increases, pipeline lifespan decreases. As oil and gas pipelines typically have an intended life of 50 years, this problem may seem relatively minor, though it must nevertheless be accounted for to avoid possible accidents or additional costs [44].

An optimal ratio between hydrogen and natural gas must be determined to ensure the stable performance and safety of the existing system. According to several recent studies as well as a report from the National Renewable Energy Laboratory (NREL), the storage and transport of hydrogen at concentration between 5-20% does not significantly affect gas quality, safety, risk, materials, and network capacity [37,45,46]. Also, studies have been reported that hydrogen blend can be realized if there is no significant problem in the durability of the pipeline caused by hydrogen embrittlement [40].

Table 4. The relationship between pipeline fatigue life and blending ratio (Modified) [44]

Added hydrogen/vol%	0	5	10	20	50
Fatigue life (year)	783	68	59	52	37

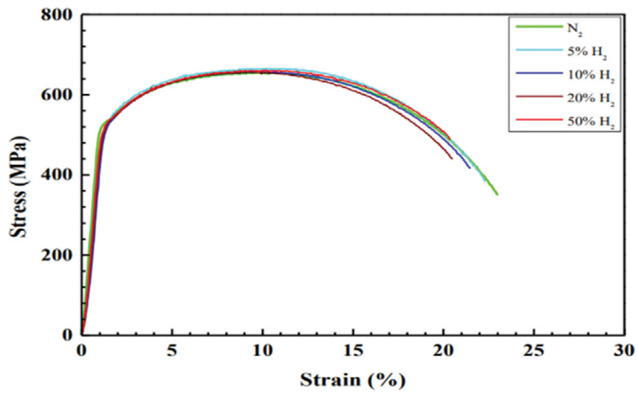

Fig. 9. Influence of the added hydrogen on the tensile properties of the smooth tensile specimens [44].

2. Hydrogen Embrittlement of Pipeline

When steel pipelines are exposed to hydrogen for an extended period, some compressed hydrogen is absorbed into the pipe wall and accumulated in the steel microstructure. This leads to hydrogen embrittlement, which refers to the deterioration of the steel's mechanical properties [47,48].

Meng et al. [44] analyzed ultimate tensile strength, yield tensile strength, elongation, and reduction of area in X80 grade steel exposed to various hydrogen blends [44]. In this experiment, nitrogen was used in lieu of methane to minimize the effect of methane impurities and ensure safety. According to their findings, even high concentrations of hydrogen did not reduce the tested steel's tensile

Table 5. Tensile data of the smooth tensile specimens (Modified) [44]

Added hydrogen vol%	Ultimate tensile strength MPa	Yield tensile strength MPa	Elongation %	Reduction of area (R_A) %
0	656.39	523.90	26.88	77.77
5	666.00	518.56	24.58	75.13
10	657.81	525.52	23.85	74.41
20	656.06	524.83	22.19	65.42
50	661.54	523.67	21.91	64.73

Table 6. The relationship between hydrogen embrittlement and blending ratio (Modified) [44]

Added hydrogen/vol%	0	5	10	20	50
E_I %	0	3.39	4.32	15.88	16.77

strength (Fig. 9). Elongation (the rate at which a material stretches during a tensile test), and reduction area (the difference between the area of the existing specimen and the smallest area after the tensile test), however, both decreased as hydrogen concentration increased (Table 5).

The hydrogen embrittlement Index (E_I) represents the reduction area (R_A) as assessed through a tensile test (Eq. (1)). E_I increases along with the concentration of hydrogen in a blend (Table 6) [44].

$$E_I(\%) = \frac{R_A^{N_2} - R_A^{H_2}}{R_A^{N_2}} \times 100 \quad (1)$$

Once material fractures have begun to form, crack propagation resistance (the expandability of the crack) decreases, and the hydrogen fatigue cracks growth rate increases. Thus, when a certain amount of force is applied to the crack tip, the fatigue crack growth rate (da/dN) of hydrogen increases compared to air or nitrogen as the range of the stress intensity factor (ΔK), which represents the magnitude of the stress field at the crack tip, increases. The fatigue crack growth rate is more than ten times higher for mixtures that include even 5% hydrogen, than those that include no hydrogen (Fig. 10) [37,49].

Fracture toughness (the resistance to fracture due to hydrogen embrittlement) decreases by more than 22% even at a hydrogen pressure as low as 2.0 MPa, as pipeline steel and joints become vulnerable to leakage [37,49]. Several factors, including hydrogen concentration, pressure, temperature, exposure time, stress state, surface conditions, and crack front characteristics of the material determine the rate of hydrogen embrittlement [50]. As hydrogen concentration increases, the leakage problem as brittleness increases [37,51]. Precautions have to be taken to prevent brittleness within pipes, and ensure their safety and longevity.

A corrosion inhibitor or other internal pipeline coating can be used to reduce the risk of hydrogen embrittlement. Corrosion inhibitors form a protective layer between the steel surface and the corrosive environment that delays metal decomposition [52-54]. The inhibitor can be periodically injected when no fluid flows through the pipe using a pipeline intervention gadget (PIG), typically used for pipeline maintenance and inspection work [55]. Such internal coatings not only reduce risk, but also improve flow efficiency by reducing surface roughness and preventing the deposition of sediments [56]. Epoxy coatings are already widely used to mitigate hydrogen embrittlement and prevent corrosion.

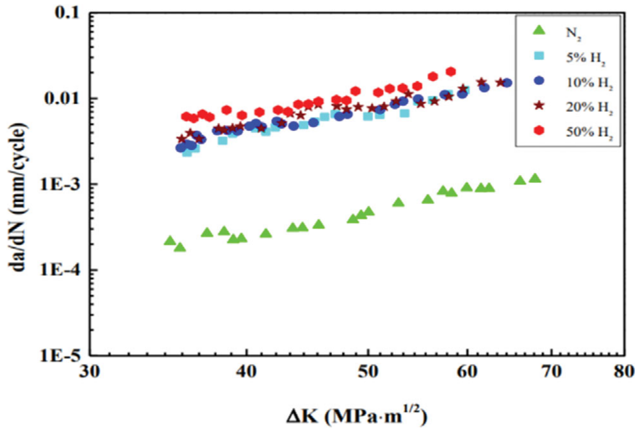

Fig. 10. The relationship between fatigue crack growth rate and blending ratio [44].

In Korea, pipelines have generally been constructed out of relatively low-strength steel, including API 5L X70. In these cases, hydrogen simply leaks out of the pipe due to the loss of the ductility, and hydrogen embrittlement is less of a risk [51]. Nevertheless, the risks of hydrogen embrittlement must be accounted for.

3. Pipeline Leak

Most pipeline problems are the result of leaks, which are themselves caused by corrosion or embrittlement, material defects, natural forces, excavation damage, and other external forces. Leakage is typically a result of either corrosion, embrittlement, or excavation damage (Table 7) [37].

Because hydrogen molecules are smaller and more mobile than methane molecules, and therefore easily penetrate seals and pipe walls, hydrogen leaks at a rate of approximately 1.3-2.8x that of methane leakage and 4x that of air [50]. Both hydrogen and methane

Table 7. Leak incidence by cause (distribution mains and services) [37]

	Mains		Services	
	Number	%	Number	%
Corrosion	55,553	36.42	71,963	21.64
Material defect	10,645	6.98	37,124	11.16
Natural force	12,924	8.47	11,305	3.40
Excavation	23,475	15.39	82,814	24.90
Other outside force	2,834	1.86	13,141	3.95
Equipment	10,293	6.75	42,279	12.71
Operation	3,866	2.53	8,557	2.57
Other	32,956	21.60	65,386	19.66
Total	152,546	100.00	332,569	100.00

Table 8. The relationship between gas loss rate and supply pressure according to hydrogen concentration (Modified) [37]

Hydrogen content (%)	At 0.41 MPa			At 0.02 MPa			At 0.002 MPa		
	H_2	CH_4	Total	H_2	CH_4	Total	H_2	CH_4	Total
0	0.0	49.4	49.4	0.0	2.5	2.5	0.0	0.2	0.2
10	32.9	44.5	77.4	1.6	2.2	3.9	0.1	0.2	0.3
20	65.9	39.5	1,054	3.3	2.0	5.3	0.3	0.2	0.4
50	164.7	24.7	189.4	8.2	1.2	9.5	0.7	0.1	0.8
100	329.3	0.0	329.3	16.5	0.0	16.5	1.4	0.0	1.4

are combustible gases, and there is a risk of fire and explosion when either gas leaks. When hydrogen is mixed with air at a volume ratio of 5%-75% or chlorine gas at a volume ratio of 5%-95%, an explosion occurs when the mixture contacts flame or heat. When hydrogen leaks from pressurized equipment, it auto-ignites as a consequence of the turbulent mixing between the surrounding air, or other ignition factors that may be present, including sparks in electrical equipment or valves [32].

In 2019 a hydrogen storage tank in Gangneung, Korea, exploded. The system operated a fuel cell by storing hydrogen obtained through the decomposition of water using electricity generated by sunlight. At the time of the accident, no palladium filter (an oxygen removal filter necessary for water electrolysis) was installed, as result of which the mixture reached a concentration of over 6% oxygen, generating static electricity and precipitating an explosion [57]. Similarly, in Norway, in 2019, an explosion at a hydrogen fueling station located in Sandvika occurred as a result of hydrogen leakage through a gap in an incorrectly assembled plug in the high-pressure storage device [58]. Such hydrogen leaks lead to safety issues, human injury, and commercial problems.

Table 8 presents leakage rate as a result of supply pressure and hydrogen concentration. The leakage rate increases as the proportion of hydrogen in a mixture increases. Where a gas is comprised of 20% hydrogen, leakage is approximately two times higher than with pure natural gas [37]. In contrast, the gas loss in pipes that operate at low pressures of 0.02 MPa or 0.002 MPa is very small. Recalling, however, that main natural gas pipeline operating pressure is 0.83-6.86 MPa and city gas supply pressure is 0.83-1.77 MPa, leak detection systems will have to be employed to reduce this risk.

The continuous leak of a gas in a closed space can reach dangerous levels. Accurate gas detection systems are already a necessity to ensure the safe operation of gas distribution networks [59], but the increase in incidence risk that corresponds with hydrogen concentration warrants even more reliance on hydrogen monitoring and leak detection technologies [32,39,41,60].

4. Hydrogen Separation Technology

When using hythane, separation technology is not required. But post-transport hydrogen separation is necessary if pure hydrogen or methane is to be used. As most hydrogen produced in Korea is currently used as fuel for hydrogen vehicles, the country must identify and employ an appropriate technology for separating high-purity hydrogen. Currently, three possible separation technologies exist: Pressure swing adsorption (PSA), electrochemical purification and compression (EHPC), and membrane technology.

PSA technology adsorbs non-hydrogen impurities from a gas mixture at high pressure (1.0-2.0 MPa) [37], and is capable of separating 98-99.99% of hydrogen from a mixture with a recovery rate of 60-90% [61]. As the operating pressure increases, the concentration of the adsorbed gas increases. So, it is a versatile technique for the separation of gas mixtures based on physical adsorption. PSA technology is the most suitable method for hydrogen concentration above 50%, that is, high concentration hydrogen such as SMR process. Therefore, about 85% of currently produced hydrogen is purified by PSA. Recently, vacuum PSA technology was developed to capture CO_2 in the SMR process [62]. Unfortunately, the process of adding a compression step, which is necessary to control the pressure of the mixture and to re-inject separated natural gas, is capital-intensive [37,61].

Membrane technology operates on the principle of selective permeation. The random motion of molecules across a permeable membrane is in equilibrium when there is equal partial pressure on both sides of the membrane [37]. When the supply gas enters the membrane separation module, hydrogen is concentrated in the permeable membrane, and gases other than hydrogen are concentrated on the membrane's residual surface (Fig. 11) [63-65]. This process is primarily used for low hydrogen concentration (<30%). The performance of membrane materials is the most critical factor determining the H_2 separation and purification efficiencies. Membranes are classifiable as one of two types: high-density or microporous [66]. Both have limitations in installing modules with large surface areas due to hydrogen embrittlement problems [63]. Nevertheless, compared to alternative gas separation technologies, membrane technology offers the advantages of simplicity in operation,

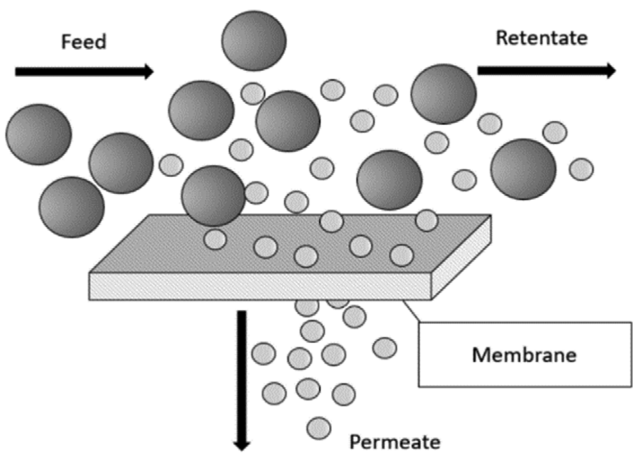

Fig. 11. Membrane separation [65].

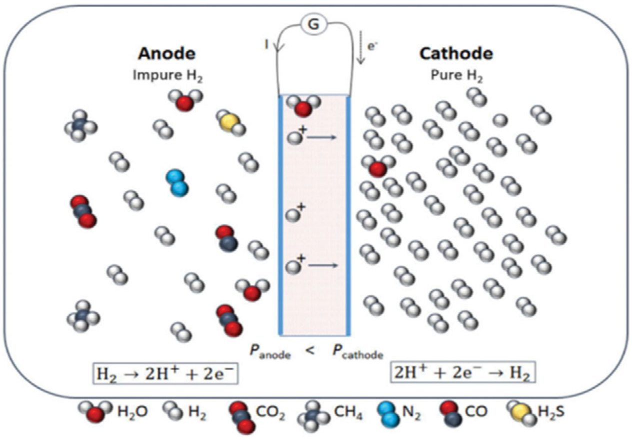

Fig. 12. Electrochemical hydrogen compressor [69].

small footprint, high-energy efficiency, low initial capital investment, and low operating costs [67,68].

EHPC separation relies on an electrochemical membrane with a fuel cell and a water electrolysis system. This system was designed to permeate only hydrogen and exclude natural gas using a proton exchange membrane (PEM), which oxidizes impure hydrogen at the anode and releases high-purity hydrogen at the cathode. In short, protons generated at the anode move selectively through the PEM, and electrons are transferred to the cathode opposite the PEM through the external circuit and recombine into hydrogen molecules. Hydrogen pure enough for use in fuel cells is extracted and accumulated through the continuous application of an electric current (Fig. 12) [69]. EHPC has many advantages over conventional separation systems. For the next process it can simultaneously compress H_2, and the CO_2 is captured and stored without further processing. Therefore, it can reduce greenhouse gas emissions. A pilot project using EHPC technology is underway in California. Additional research and development is necessary, however, before EHPC can be used at high temperatures, and to learn more about the life of the electrochemical hydrogen membrane, and the influence of pre-separation various impurities [70,71].

According to several recent studies, a hybrid system in which multiple separation technologies are applied simultaneously offers promising means of separating hydrogen from a mixture [37,72, 73]. Such hybrid systems combine a high-density membrane that uses palladium with a microporous membrane that uses a carbon molecular sieve (CMS) [73]. An alternative hybrid method based on membrane technology and pressure swing adsorption (PSA),

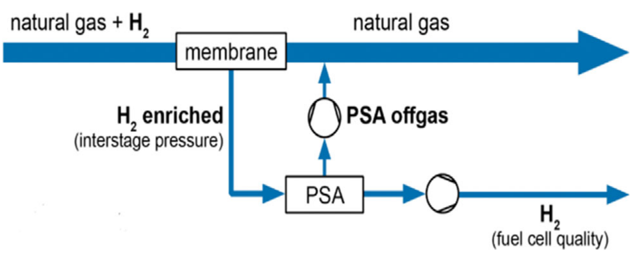

Fig. 13. Hybrid membrane technology [61].

Table 9. Proportion of blending for projects operating or planned by country

Nation	Hydrogen mixing ratio (%) for operating and planning projects	References
Germany	20	[75]
USA (California)	3-15 or 20	[42,78,79]
France	20	[82]
Australia	10	[85]
UK	20	[59,86]
Canada	5	[87]
Netherlands	20	[70]

which uses membrane technology to pre-concentrate and upgrade hydrogen quality using PSA, has also been shown to enable efficient hydrogen separation at various hydrogen supply concentrations (1-10%) (Fig. 13) [61].

HYDROGEN BLENDING GAS SUPPLY PROJECT BY COUNTRY

The concentration of hydrogen appropriate to send through a natural gas pipeline network varies depending on pipeline characteristics and country. A number of pilot projects are underway to determine the ideal mixing ratio, accounting for the need to prioritize both efficiency and safety (Table 9).

Germany currently limits hydrogen to 10% of a mixture [74]. In 2019, however, the European energy company E.on began the 'H2-20 project', which may confirm that 20% green hydrogen mixtures can be transported with no problem. The project will assess the effect of mixed hydrogen on 400-500 appliances connected to a local distribution network, and runs until 2023 [75]. Another project (H2HoWi) is also underway, in which blend concentration is gradually increased to confirm that the presence of more hydrogen does not diminish the robustness of the pipe material. This project aims to supply 100% hydrogen and is expected to finish by 2023 (Fig. 14) [74,76,77].

In California, 3-15% hydrogen mixtures are blended and transported through a natural gas pipeline, then separated and purified in an EHPC system, from which 10 kg of hydrogen per day is sent on to gas stations. We expect that more than 100 kg of hydrogen per day can be sent through such a system within the next two years. This project began in March 2021 and is expected to finish up in the third quarter of the same year [63,78]. To establish a technical standard for hydrogen injection concentration throughout California, green hydrogen will be produced using surplus electricity generated by solar panels and injected into a natural gas pipeline for storage and usage, forming 1-20% of the mixture in the pipeline. A location for this project will likely be chosen in 2021, and it is expected to run until 2030 [42,79,80].

France has conducted a technical and economic feasibility study for hydrogen injection into the existing gas pipeline network. A CAPEX analysis of hydrogen blending and transportation reported that hydrogen can form up to 6% of a mixture and pass through existing natural gas pipelines with no significant modifications

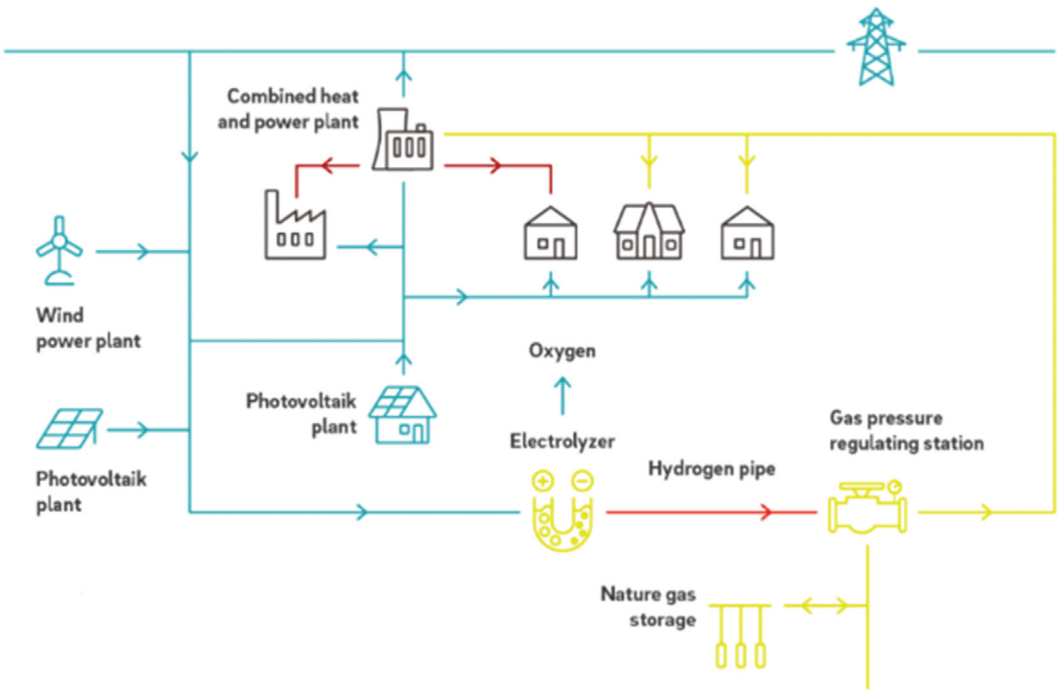

Fig. 14. Schematic of hydrogen blending gas supply project in Germany [77].

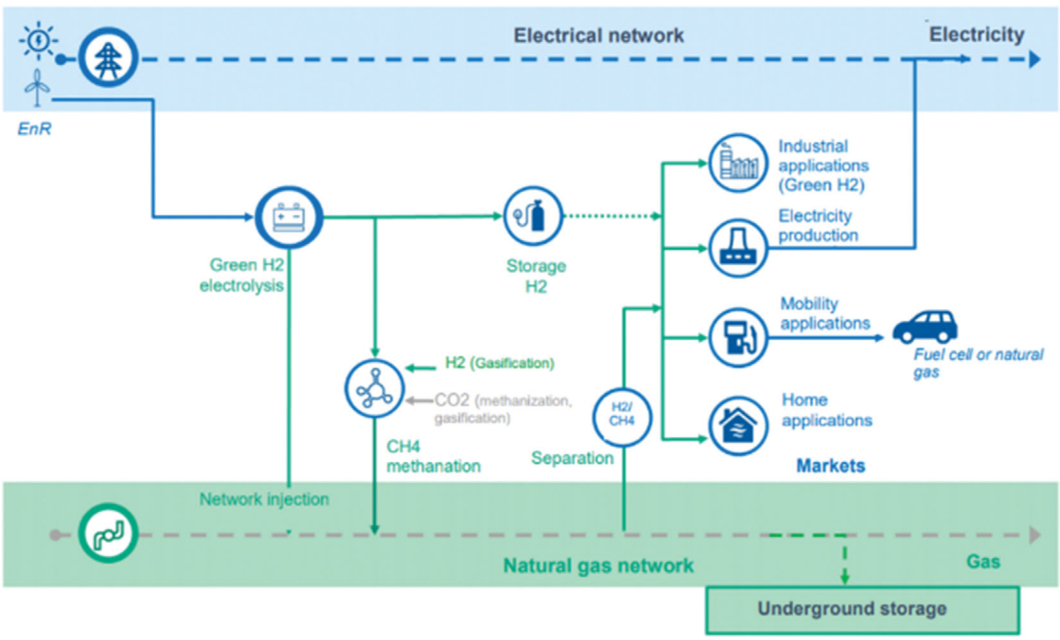

Fig. 15. Schematic of hydrogen blending gas supply project in France [81].

required. But when the presence of hydrogen exceeds 10%, the process would require additional money to be spent on transportation, storage, and distribution systems [81]. Two other pilot projects, one producing hydrogen by PEM electrolysis that injects a 20% hydrogen mixture into the natural gas distribution networks of Le Petit and Dunkirk Urban Community, and the other testing (GRHYD) the use of hythane (hydrogen-methane mixture gas) for household use, are ongoing (Fig. 15) [82].

Australia is performing its own 'HyP SA' project that mixes 5% of the hydrogen produced by PEM electrolysis into Mitchell Park, South Australia's existing gas network (Fig. 16) [83,84]. In 2020 the project began producing hydrogen for the first time, and the test was to run until mid-2021. Another project (HyP Gladstone) based on the HyP SA facility, will supply mixture gas to more than 770 homes by including up to 10% hydrogen in the supplied mixture. This project is scheduled to produce its first hydrogen in 2022 [85].

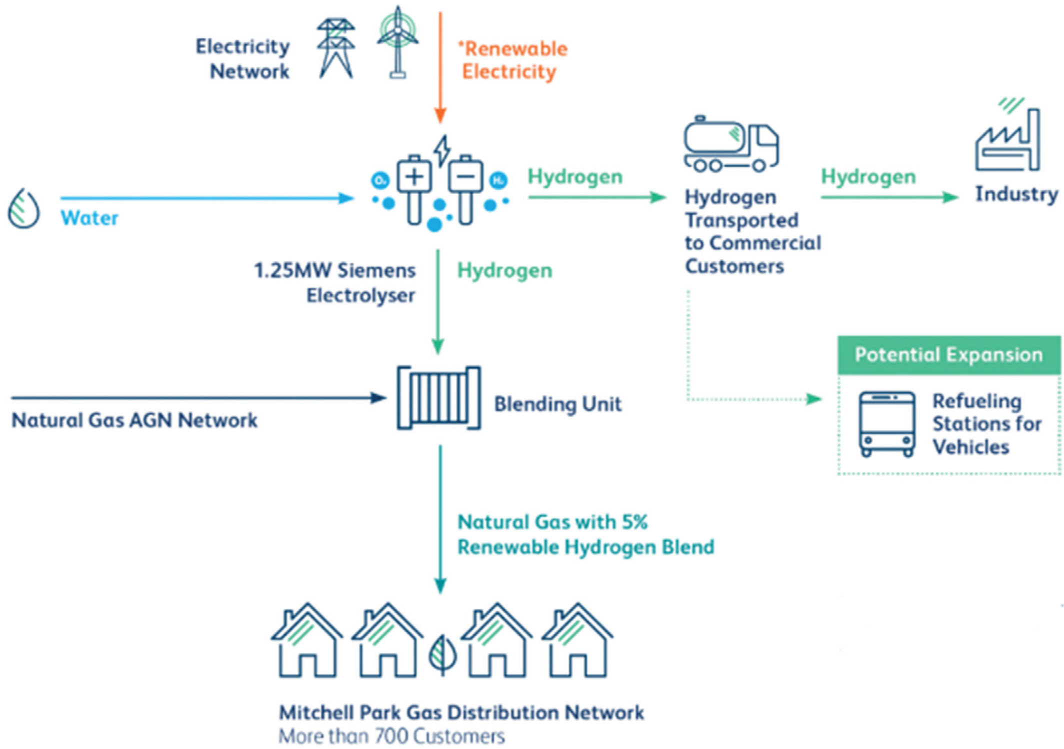

Fig. 16. Schematic of hydrogen blending gas supply project in Australia [84].

In the UK, hydrogen is not permitted to exceed 0.1% of the mixture sent through natural gas networks. The 'HyDeploy' project is current testing the feasibility of sending mixtures consisting of 20% without increasing the risk of harm to the user or modifying existing equipment [59]. Some pipeline networks are being tested for their possibility of mixing hydro-electrolytic hydrogen. In 2020, Keele University reported that a pipeline network and consumer-grade gas equipment can be safely operated even when 20% hydrogen mixtures are injected are injected into the supply chain [86].

In July 2020 Canada announced the 'Fort Saskatchewan Blending' project, the first in Alberta to inject hydrogen at a maximum concentration of 5% into the natural gas distribution network [87, 88]. The Netherlands has also successfully demonstrated that the safe injection of mixtures consisting of up to 20% hydrogen into the natural gas grid is possible through their 'Ameland' project [89].

In sum, projects studying the supply of mixed gas using the existing natural gas piping network, either by separating hydrogen and natural gas from a mixed gas or supplying mixed gas (hythane) without separating, are underway in a number of countries.

HYDROGEN SUPPLY PLAN USING DOMESTIC NATURAL GAS PIPELINE

This study examined the feasibility of transporting hydrogen-natural gas mixtures through existing natural gas pipelines. Considering Korea's particular geographic and industrial conditions, and the need to ensure a stable supply of hydrogen to meet the needs of a growing global economy, we suggest that three off-site supply methods are suitable for potential use. We consider on-site methods inappropriate in light of the problem with the treatment and reduction of CO_2 generated during hydrogen production.

First, hydrogen mass-produced by SMR can be blended at an appropriate blend ratio with natural gas at a hydrogen production base and transported to a supply management site or hydrogen fueling station, through existing pipelines. Once there, the hydrogen can be separated and supplied to the end consumer. If an appropriate blend ratio is selected, a stable supply of hydrogen using a natural gas pipeline is possible.

Alternatively, hythane can be transported through existing natural gas pipelines and used without separation. While initially developed and deployed for the automotive sector, there is some research to suggest that hythane is appropriate and safe for domestic use. Specifically, the UK's 'Hydeploy' project demonstrated that hythane gas at a concentration of 20% can be safely and economically transported through standard gas pipes and used by household appliances. Besides we note that research on hythane gas is ongoing in France.

Third, hydrogen can be transported to its final destination by compressed hydrogen trucking. In larger countries, including the United States and Canada, a pipeline is the most efficient means of transport, as there is a volumetric limit to supply the required amount through trucking. While the growth of a hydrogen economy in Korea will eventually require pipeline use to maximize efficiency, trucking offers a short-term solution to the problem of ensuring that available produced hydrogen is transported to where it is needed.

Most Korean-produced hydrogen is currently used as an industrial raw material, but its use has gradually expanded to include transportation, buildings, and power generation. The time has therefore come for policymakers to assess the options for hydrogen transport and develop the necessary capacity to meet the rapidly increasing demand for a cost-effective and stable hydrogen supply.

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