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The Nuclear-Hydrogen Renewables Economy

Charles Forsberg
Oak Ridge National Laboratory*
P.O. Box 2008; Oak Ridge, TN 37831-6165
Tel: (865) 574-6783; Fax: (865) 574-0382
E-mail: **forsbergcw@ornl.gov**

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THE NUCLEAR-HYDROGEN RENEWABLE ECONOMY

Charles W. Forsberg
Oak Ridge National Laboratory
P.O. Box 2008, Oak Ridge, TN
Tel: (865) 574-6784; forsbergcw@ornl.gov

ABSTRACT

Different technologies have different characteristics. The intrinsic characteristics of renewable energy systems, hydrogen, and nuclear energy suggest a natural coupling of these three technologies to reduce costs, help eliminate our dependence on foreign oil, and reduce greenhouse gas emissions and the associated dangers of climatic change.

Hydrogen can potentially address some of the major challenges associated with the use of renewable energy sources. The abundant renewables, such as wind and solar, have variable electricity production rates that do not match our needs for electricity. The sun does not always shine, and the wind does not always blow. A Hydrogen Intermediate and Peak Electric System can convert hydrogen and oxygen to electricity when the wind does not blow and the sun does not shine. Although biomass is currently being converted to ethanol, a liquid fuel, the ethanol that can be produced from available biomass is insufficient to meet the total demand for liquid fuels for our transport system. The addition of hydrogen to biomass can increase the liquid fuel yield per unit of biomass by a factor of 3 to 4 and enable biomass to become our primary source of liquid fuels.

Hydrogen, as an energy carrier, is fundamentally different from electricity. Whereas electrical systems can transport energy in both directions through the transmission grid, hydrogen, like natural gas, flows from high to low pressure. Hydrogen can be inexpensively stored on a large scale but is expensive to store on a small scale. Economic hydrogen production is intrinsically a large-scale operation. As a consequence of the centralized transport, storage, and production characteristics of hydrogen, the use of nuclear energy (a centralized energy technology) to produce hydrogen is a natural coupling.

1. INTRODUCTION

The national energy debate is often framed as an either/or choice between nuclear, fossil, and renewable energy sources. However, each energy source has its own unique characteristics, strengths, and weaknesses. As a consequence, combining different energy sources together usually leads to reduced costs and reduced environmental impacts. Today we are rethinking our energy systems because of two problems: (1) our dependence on foreign oil and the resultant involvement in unstable parts of the world and (2) the potential for major changes in climate, ocean life, and environment resulting from the changing composition of the atmosphere caused by the burning of fossil fuels. The above factors suggest that our energy future may lead to a nuclear-hydrogen renewables economy.

This paper explores such a future based, to the degree possible, on the intrinsic characteristics of nuclear energy, hydrogen, and renewables. For example, the intrinsic characteristics of nuclear hydrogen (hydrogen made using nuclear energy) are its centralized production, the co-production of hydrogen and oxygen from water, and the availability of low-cost heat from the reactor. These characteristics are independent of the specific hydrogen production technology—be it centralized electrolysis (electricity and water to hydrogen and oxygen), hybrid cycles (heat, electricity, and water to hydrogen and oxygen), or thermochemical cycles (heat and water to hydrogen and oxygen).

Three questions are addressed. Can hydrogen enable the use of biomass to meet all our liquid fuels needs? Is hydrogen required for the large-scale use of renewable electricity? Is nuclear energy the ultimate source of hydrogen?

2. BIOMASS, HYDROGEN, AND LIQUID FUELS

Our transportation system is based on liquid fuels; however, these oil-based fuels are increasingly expensive, come from politically unstable regions, and are a major source of greenhouse gases. Major initiatives are underway to replace oil with biomass-derived liquid fuels such as ethanol, which would help prevent increases in atmospheric carbon dioxide levels. Plants convert atmospheric carbon dioxide, water, and solar energy to biomass. The burning of biomass-derived liquid fuels returns the carbon to the air as carbon dioxide, a complete cycle that does not impact the carbon dioxide levels of the atmosphere. As a consequence, there are strong incentives to use biomass for liquid fuel production.

It is projected that by 2030 up to 30% of the liquid fuels consumed in the United States could be made from biomass,[1–2] with an ultimate production capability twice as large. Today corn (starch) is converted to ethanol; however, the supplies of corn are limited. The longer-term future is the use of cellulose to make liquid fuels. Table 1 shows the estimated sustainable biomass production for the United States[1] to be about 1.3 billion dry tons per year. All of the biomass except "grains to biofuels" and some of the "process residues" are cellulosic feedstocks. The large biomass feedstocks are crop residues (primarily corn stover) and perennials such as switchgrass and poplar trees specifically grown for energy use on marginal lands. Long-term studies[3] indicate that biofuels could provide about 30% of the global demand in an environmentally acceptable way without impacting food production. However, the resources of biomass are ultimately limited. The question is whether we can more efficiently use our biomass to ultimately meet all our liquid fuel needs.

Table 1. Ultimate Biomass Availability in the United States

Agriculture		**Forest Residues**	
Source	**Millions of dry tons**	**Source**	**Millions of dry tons**
Crop residues	428	Manufacturing residue	145
Perennial crops	377	Logging debris	64
Grains to biofuels	87	Fuel reduction treatments	60
Process residues	106	Fuel wood	52
		Urban wood waste	47
Total agriculture	998	Total forest	368

Two strategies are being considered for more efficient use of biomass. The first is to reduce the use of biomass and fossil fuels for process heat in the production of biomass liquid fuels. Today the energy input to grow corn, transport it, and convert it into ethanol is about 70% of the energy value of the ethanol. Half that energy is in the form of low-pressure steam used primarily in distillation columns to separate the ethanol from the fermentation mash. Ethanol production is viable because much of the fossil energy input is in the form of solid and gaseous fossil fuels that are converted to a high-value, high-octane (~112 octane) liquid fuel. In Brazil, where ethanol is made from sugarcane, the sugar is squeezed from the sugarcane and converted to ethanol while the crushed sugar cane plant is burnt to produce steam for the distillation columns. Although this approach reduces the use of fossil fuels, it eliminates the option of converting the crushed sugarcane plant to liquid fuels. Several strategies have been proposed to reduce the fossil and biomass energy used for process heat in biomass-to-liquid-fuel production. In the Midwest, ethanol plants could be built near existing nuclear power plants and use the low-pressure steam from these nuclear plants. With the recent rise in natural gas prices, the cost of steam from nuclear plants is now about half that from natural gas.[4–5] An alternative longer-term strategy is to develop biomass-to-liquid fuel processes that avoid the energy-intensive distillation processes (described below).

The second longer-term strategy is to make better use of the biomass. When biomass with existing commercial technologies is converted into ethanol, only a fraction of the biomass carbon becomes part of the liquid fuel. Much of the biomass is consumed (oxidized to CO_2) as an energy source to convert the biomass to fuel ethanol. For example, in the conversion of corn to ethanol (CH_3CH_2OH), about one-third of the original carbon is part of the ethanol product, another third is released as carbon dioxide (the respiration product of the yeast that made the ethanol), and the final fraction contains the non-fermentable protein-rich components of the corn that becomes animal food.

$$\text{Biomass} \rightarrow CH_3CH_2OH + CO_2\uparrow + \text{Residues}$$

Another alternative exists: add hydrogen from an outside source and convert every atom of carbon into high-grade liquid hydrocarbon fuels—not ethanol. The energy value[6–7] of these liquid fuels is 3 to 4 times greater than that achieved by using biological processes to produce liquid fuels. There are two strategies to accomplish this.

If hydrogen and biomass are fed to the Fisher-Tropsch process, all of the carbon in the biomass can be converted to liquid fuels. Fisher-Tropsch is the classical multi-step process that converts fossil fuels such as coal and natural gas to syngas (a mixture of CO and H_2) that is in turn converted to liquid hydrocarbons such as diesel. Hydrogen serves as the energy source for the Fisher-Tropsch process and is used as the source of the extra hydrogen needed to fully convert biomass (a mixture of compounds containing carbon, hydrogen, and oxygen) to a hydrocarbon fuel. As a secondary benefit, this option[8] produces gasoline, diesel fuel, and jet fuels—all of which are compatible with our current transport system.

$$\text{Biomass} + H_2 \rightarrow (CH_2)_n + H_2O$$

Alternatively, we can add hydrogen directly to biomass[9–10] to produce liquid fuels (hydrogenation). Several processes, in the early stages of development, have the potential for substantially lower costs than Fisher Tropsch because (1) theoretically less hydrogen is required per unit of liquid fuel produced and (2) these alternative processes can potentially be implemented on a smaller scale. For production of liquid fuels from biomass, plant size is a major issue. Biomass is bulky and heavy; thus, high costs are associated with transporting biomass any distance. For this reason, ethanol plants are distributed across the Midwest Corn Belt. There is a trade-off between the economics of scale for the biomass-to-fuel plants and the costs of biomass transport. The central requirement for both options is the need for hydrogen.

Major efforts are underway to develop economic technologies to directly use hydrogen as a fuel in vehicles. This credible possibility is attractive because hydrogen allows the use of fuel cells, an energy conversion system that is more efficient than the internal combustion engine and intrinsically less polluting. However, the challenges are large. Liquid hydrocarbon fuels for transportation have major advantages in terms of high energy density and safety. Table 2 shows the properties of different possible future fuels[8] with different types of engines. These data indicate why making liquid hydrocarbon fuels such as diesel fuel from biomass may be a lesser challenge than developing hydrogen-fueled vehicles—except for special applications (such as urban buses and delivery vehicles), where weight is not major constraint.

Table 2. Comparisons of Different Fuel Systems for Automobiles

H2 Storage Mechanism[a]	Engine Type and Eff (%)[b]	Est. Miles for a Tank of Fuel	LFL[c] (vol. %)	UFL[d] (vol. %)	Toxicity[e]	Storage Pressure (bar)	Storage Temp.
Compressed H_2	Fuel Cell: 70	219	4	74.2	MAH	700	Room
Liquefied H_2	Fuel Cell: 70	264	4	74.2	MAH	1	4 K
Metal hydride	Fuel Cell: 70	132	4	74.2	MAH	1	Room
Liquefied NH_3	Hybrid: 40	234	15.5	27	IDLH: 500 ppm	10	Room
Compressed CH_4	Hybrid: 40	416	5	15	AH	700	Room
Liquefied CH_4	Hybrid: 40	418	5	15	AH	1	109 K
Methanol	Hybrid: 40	285	6	36	TWA: 200 ppm; IDLH: 6000 ppm	1	Room
Ethanol	Hybrid: 40	285	3.3	19	TWA: 1000 ppm IDLA: 3300 ppm	1	Room
$LiBH_4$	Fuel Cell: 70	245	4	74.2	MAH	1	Room
Diesel hybrid	Hybrid: 40	800	0.77	5.35	Low (>1369 ppm for 8 h)	1	Room

[a]Metal hydrides at 5% H_2/lb metal at 8 lb/ft^3; Liquefied NH_3 = liquefied ammonia; $LiBH_4$ (lithium borohydride) as a 50% slurry in water.
[b]Eff = engine efficiency.
[c]Lower flammability limit.
[d]Upper flammability limit.
[e]MAH = minor asphyxiation hazard; AH = asphyxiation hazard; IDLH = Immediately Dangerous to Life or Health; TWA = Time Weighted Average, typically over 8 hours.

3. WIND, HYDROGEN, AND ELECTRICITY

If renewables such as wind and solar energy are to meet a significant fraction of our electrical demand, there will be a massive demand for non-renewable electricity at night, during cloudy weather, or when the wind does not blow. Hydrogen can be used to meet this highly variable electrical demand. Three classes of hydrogen-fuel options exist.

- *Combined-cycle plants*. Hydrogen can be used as a replacement for natural gas in traditional heat-to-electricity technologies such as turbines. The current state-of-the-art commercial technology[11] to meet intermediate and peak electric loads is the integrated combined-cycle plant. The natural gas is fed to a Brayton power cycle (jet engine) that produces part of the electrical power. The hot exhaust from the Brayton cycle is then fed to a conventional steam boiler to produce steam, which is sent to a conventional steam turbine. The plant efficiencies are ~55%, with overnight capital costs of ~$570/kW(e).

- *Fuel cells*. In the longer term, fuel cells that directly convert hydrogen to electricity have the potential for higher efficiency and potentially lower costs.

- *Hydrogen Intermediate and Peak Electricity System (HIPES).* Unlike fossil hydrogen production methods, nonfossil hydrogen production methods convert water to hydrogen and oxygen. The hydrogen and oxygen may be used to produce intermediate and peak electricity at potentially lower capital costs and significantly higher efficiencies[12–13] than burning hydrogen in combined-cycle plants or in fuel cells. This new technology option is being explored but has not yet been demonstrated.

HIPES consists of three major components (Fig. 1).

- *Hydrogen production*. Hydrogen is produced from water, with the by-product production of oxygen. The hydrogen and oxygen can be produced by (1) dedicated nuclear plants or (2) use of grid electricity at times of low electrical demand.

- *Hydrogen and oxygen storage*. Underground storage facilities are used for the low-cost storage of hydrogen and oxygen on a daily, weekly, or seasonal basis.

- *Hydrogen-to-electricity conversion*. Fuel cells, steam turbines, or other technologies are used to convert the hydrogen and oxygen to electricity. The use of pure oxygen with the hydrogen distinguishes this technology from other methods used to produce peak electric power.

The economics of HIPES are based on (1) minimization of the cost of hydrogen production by producing hydrogen at the maximum rate possible from capital-intensive facilities or using low-cost electricity at times of low electricity demand; (2) low-cost bulk hydrogen and oxygen storage; and (3) low-capital-cost, high-efficiency conversion of hydrogen and oxygen to electricity. Because of the wide variation in peak electricity demand, the hydrogen-to-electricity production capacity is many times that of the hydrogen production capacity.

Because the system design is driven by the peak electrical need, the hydrogen-to-electricity component is described first. Two technologies (unconventional fuel cells and unconventional steam turbines) have been identified for conversion of hydrogen and oxygen to electricity at higher efficiencies and lower capital costs than those available with traditional combined-cycle plants.

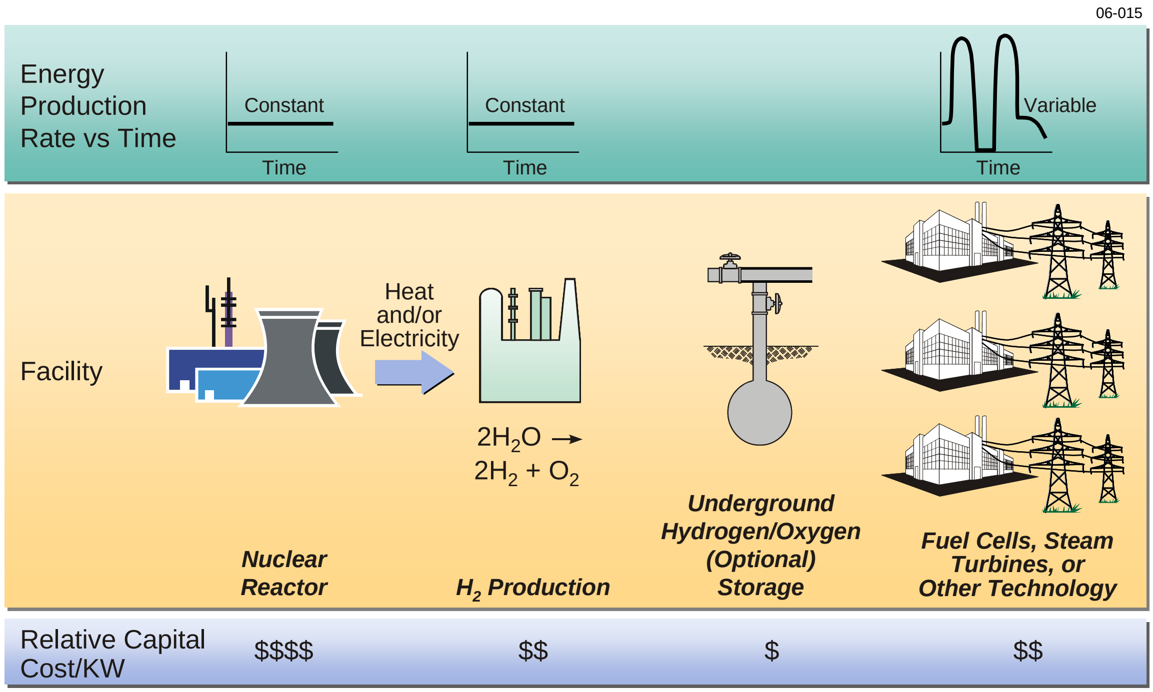

Fig. 1. Hydrogen Intermediate and Peak Electrical System.

The traditional technology to convert heat to electricity is the steam turbine. Heat from burning fossil fuels, nuclear reactors, or solar sources converts water to steam. To produce electricity, the steam is sent through a turbine that turns a generator. Historically, steam turbine peak temperatures have been limited to ~550°C because of corrosion in the boiler where the water is converted to steam. This restriction has limited the efficiency of the process to ~40%. The most expensive component is the boiler, because it requires massive amounts of surface area to transfer heat from its source (burning fossil fuels, nuclear heat, or concentrated sunlight).

If hydrogen and oxygen are available, an alternative steam cycle (Fig. 2) exists.[13–14] Hydrogen, oxygen, and water are fed directly to a burner to produce high-pressure, very high temperature steam. Because the combustion temperature of a pure hydrogen–oxygen flame is far beyond that acceptable for current materials of construction, water is added to lower the peak temperatures. The technology is that of a low-performance rocket engine. The resultant steam is fed directly to a very high temperature turbine that drives an electric generator. Through the use of advancing gas turbine technology with actively cooled blades, it is expected that peak steam temperatures at the inlet of the first turbines will approach 1500°C. The projected heat-to-electricity efficiency for advanced turbines approaches ~70%.

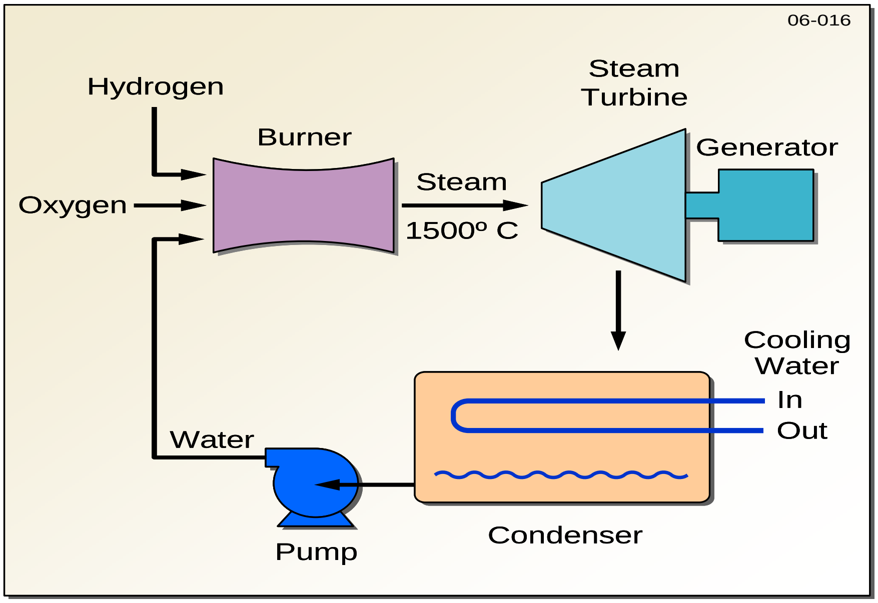

Fig. 2. Oxygen–hydrogen–water steam cycle.

The technology is based on ongoing development of an advanced natural-gas electric plant that uses oxygen rather than air.[15] Figure 3 shows the test burner that replaces a steam boiler. Combustors with outputs of ~20 MW(t) are being tested. With a natural gas and oxygen feed, a mixture of steam and carbon dioxide (without nitrogen) is created. In the condenser, the steam is condensed and the carbon dioxide is available for (1) injection into oil fields to increase the recovery of oil and/or (2) for sequestration. The higher heat-to-electricity efficiency and the production of a clean carbon dioxide gas stream for long-term sequestration of the carbon dioxide greenhouse gases create strong incentives to develop the technology for burning of fossil fuels.

HIPES has potentially lower capital costs than the hydrogen-fueled combined-cycle plants [$570/kW(e)], as previously discussed.[14] The high-temperature turbine remains, but the need to compress air as an oxidizer is eliminated. The massive flow of nitrogen gas (~80% of air) through the system is eliminated. Equally important, the expensive high-surface-area boiler in the combined-cycle plant is also eliminated and replaced by a small burner. These changes simultaneously increase efficiency (55 to 70%) and lower capital costs. However, HIPES represents a new option with significant uncertainties remaining.

Fig. 3. Fuel-oxygen combustor (Courtesy of Clean Energy Systems).

4. HYDROGEN AND NUCLEAR ENERGY

As an electrical carrier, hydrogen is fundamentally different from electricity. On either a small or large scale, electricity can be transported efficiently at relatively low costs via transformers, power electronics, and transmission lines. The electrical distribution system is a two-way system in which electricity can move both directions through transformers. In contrast, hydrogen transport involves the moving of mass. As a light gas, its characteristics are very different from those of liquid fuels. These differences have major implications for the production, transport, and use of hydrogen.

Production economics. The cost of hydrogen and the cost of hydrogen compression are strongly dependent on the scale of operations. The massive economics of scale reflect fundamental technological factors. For example, whereas small efficient transformers exist to increase the voltage (pressure) of electricity, no one has successfully built small and efficient hydrogen compressors. This economic reality is a consequence of the fact that hydrogen has the lowest molecular weight of any gas. The low molecular weight requires hydrogen compressors to operate at much higher speeds than other gas compressors. Several internal surface-to-volume effects result in small-compressor inefficiencies. The same low molecular weight implies large (expensive) production facilities unless the equipment is operated at high pressures. The safety and instrumentation requirements are nearly scale independent. While the production costs for different methods of electricity production (coal, nuclear, wind, etc.) vary by a factor of 3 while the plant sizes vary by 3 orders of magnitude, the production costs for hydrogen from primary energy sources show strong economics of scale.

As the lightest and smallest atom, hydrogen tends to leak from most systems and diffuses through most materials. The leakage losses are dependent upon the external surface area of the equipment. As the area increases, the losses increase as well. This favors large production systems with small surface-to-volume ratios and presents a fundamental challenge for solar hydrogen production systems similar to photovoltaic cells that have massive surface areas.

Markets. Unless it is used directly as a fuel, the largest markets for hydrogen are large industrial facilities that have large demands for hydrogen provided on a continuous basis.

Storage. Only one nonfossil method currently exists for weekly or seasonal storage of large quantities of energy (Quads) at low cost—storage of hydrogen as compressed gas in large underground facilities. No other low-cost technologies have been developed. Underground storage is the same technology used for seasonal storage of natural gas.[16] In the natural gas industry, the most rapid consumption occurs in winter. However, it is uneconomical to design transcontinental pipelines and natural gas treatment plants to meet peak natural gas demands. Instead, the natural gas is produced and transported at a relatively constant rate throughout the year. A variety of different types of large underground storage systems in different geologies at locations near the customer are used to store the excess natural gas produced during the summer for subsequent use in the winter (Fig. 4).

- *Man-made caverns*. Underground caverns are mined, with access to the surface provided via wells. The most common type of cavern is located in salt domes, where the cavern is made by pumping down fresh water and dissolving out the salt.

- *Pressure-compensated man-made caverns*. Underground caverns are mined, with access to the surface provided via wells. In addition, a surface lake connected to the bottom of the man-made cavern is created. The water pressure from the surface lake results in a constant pressure in the cavern that is equal to the hydraulic head of the water.

- *Porous rock with caprock*. Porous rock exists with an impermeable caprock above it that forms a natural trap for gases (inverted "U" shape). Wells are drilled into the porous rock, and injected gas pushes out whatever other fluids exist in the rock. Much of the world's natural gas is found in this type of geological trap. Similar structures are found worldwide without natural gas, many of which have been used for natural gas storage. In most cases, these are parts of aquifers and the injection of the gas pushes out the water.

The total existing natural gas storage capacity in the United States is 8.4×10^{12} ft^3, which is equivalent to about one-third of the natural gas consumed in the United States in 1 year. These facilities are large, with average storage capacities between 10 and 20 billion cubic feet. The usable capacity depends upon the required pressure at which the natural gas must be delivered to the pipeline and the rate of delivery. For high-pressure gas delivery, the capacity is about one-half, with one-half of the gas used as buffer gas to maintain storage facility pressure and minimize compression back to pipeline pressures.

The same technology is used commercially for storage of gaseous high-pressure hydrogen in salt to match variable industrial hydrogen demand with production, including assurance of hydrogen supply while hydrogen production facilities are shut down for maintenance. Hydrogen storage should be viable in other geologies as well. Measurements of the helium content of many types of rocks provide reasonable assurance that hydrogen can be held in many geologies for long periods of time. Although there have been limited assessments and experience with hydrogen storage in some other geologies, the technology is not fully commercial.

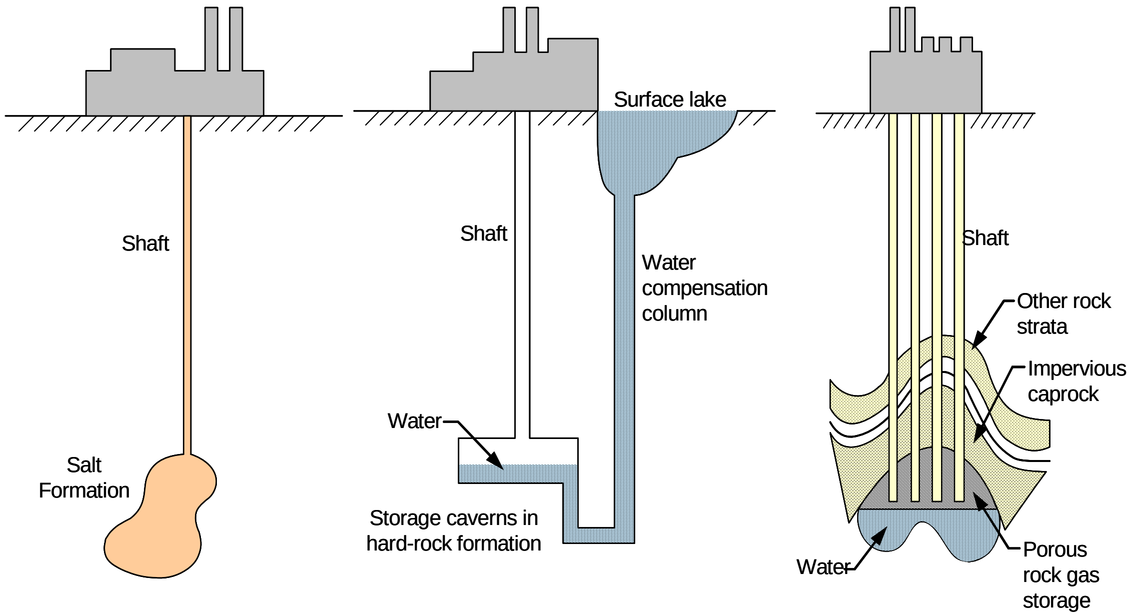

Fig. 4. Technologies for underground storage of compressed gases.

The capital cost[12, 17–18] of an underground facility to store 1 GW-year of hydrogen (lower heating value) is estimated to be about $200–$400 million ($0.80–$1.60/kg storage capacity). The total value of the hydrogen stored in such a facility will exceed the total capital cost of the facility. Although the capital cost is sufficiently low as to make viable the seasonal storage of hydrogen, the technology is available only on a large scale.

Transportation. Because of the inefficiency and expense of small compressors, the use of small scale hydrogen compression to move hydrogen from distributed hydrogen production systems to centralized storage is both inefficient and capital intensive. However, it is relatively easy and economic to move hydrogen from centralized facilities to distributed users down the pressure gradient such as is done with natural gas. On the other hand, economics and safety limit the distance that oxygen can be transported.

The combined economics of hydrogen transport and storage result in a major competitive advantage for centralized hydrogen production compared to with decentralized hydrogen production technology. A decentralized hydrogen production technology must be much less expensive than a centralized hydrogen production technology to overcome these penalties yet production technologies favor large facilities. At the most fundamental level, hydrogen is intrinsically a large-scale technology.

Nuclear energy is a large-scale centralized source of energy that requires high levels of technological competence. Large economic incentives (the need for security, training, maintenance, etc.) favor siting multiple reactors in large nuclear parks. Many of the institutional challenges would be reduced if nuclear energy could be confined to such sites. The characteristics of nuclear energy and hydrogen match. The economics of both systems strongly favor large-scale centralized facilities. Large-scale hydrogen production, storage, and use require high levels of design and operational competence. Hydrogen and nuclear energy are natural complements, regardless of whether the hydrogen is made by low-temperature electrolysis, high-temperature electrolysis, or thermochemical systems.

5. CONCLUSIONS

Every energy technology has fundamental characteristics that give it unique advantages for some missions and unique disadvantages for other missions. The characteristics of renewables, hydrogen, and nuclear energy suggest strong synergisms and a potential movement toward a nuclear-hydrogen renewable energy economy.

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