# Hydrogen Markets:
# Implications for Hydrogen Production Technologies

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**Abstract**

Different existing and future markets for hydrogen have varying characteristics that impact the competitive advantages or disadvantages of hydrogen generated by alternative technologies. Long-term stable markets favor higher-capital-cost, lower-operating-cost technologies. Dispersed small markets favor modular technologies, such as electrolysis, while large markets may favor centralized nuclear-hydrogen production options using thermochemical cycles that convert heat plus water into hydrogen and oxygen. Potential restrictions on greenhouse gas emissions may result in extremely large demands for hydrogen for liquid-fuel production and other uses, if the hydrogen production technology does not emit greenhouse gases to the atmosphere. Some hydrogen production technologies also create by-products such as oxygen. When a demand for such by-products exists, these by-products may also define the preferred hydrogen production technologies. Potential hydrogen markets, the characteristics of these markets, and some of the implications are described.

## 1. Introduction

The development of hydrogen production technologies requires identification of potential markets and the constraints associated with those markets. The markets partly define the requirements for the production technology as well as potential partners to commercialize new hydrogen production technologies. For example, if a potential user of hydrogen also required large quantities of oxygen, that user (if it were a partner) would only be interested in technologies that co-produce hydrogen and oxygen. Markets are not always easy to identify—particularly when the technology might not be fully deployed for several decades. This paper is an effort to identify potential major markets and some of the constraints associated with those markets. This provides a basis to allow assessment of the requirements for hydrogen production technologies.

The major future markets for hydrogen depend primarily upon four factors: (1) the future cost of hydrogen, (2) the rate of advances of various technologies that use hydrogen, (3) potential long-term restrictions on greenhouse gases, and (4) the cost of competing energy systems. For non-carbon-dioxide-emitting hydrogen production technologies (nuclear, renewables, and fossil fuels with carbon dioxide sequestration), potential restrictions on carbon dioxide emissions to the atmosphere are a key factor in the potential size of future markets. With the Kyoto Accord now in effect in most of the world (except the United States and Australia), there are growing incentives to reduce greenhouse gas releases. Such incentives already exist in some countries. For example, Norway taxes carbon dioxide emissions and thus creates a strong incentive to minimize these releases (Herzog and Golumb 2004). In any scenario where there are restrictions on carbon dioxide releases to the atmosphere and when non-greenhouse hydrogen production techniques at reasonable costs are available, extraordinary demands for hydrogen will likely exist.

## 2. Markets

Eleven potential major markets for hydrogen are considered, several of which represent alternative markets. Each market is characterized by several parameters that impact the choices of preferred production technologies as illustrated in Table 1 and defined below.

- *Oxygen use*. Some markets require both oxygen and hydrogen. Such markets favor hydrogen production technologies that co-produce oxygen.

- *Heat use*. Some process applications require hydrogen and heat. This encourages co-location of the hydrogen production plant with the application.

- *Existing market*. Hydrogen is used in many markets. For existing applications, user technology is not the market constraint. If the cost of hydrogen is reduced, market use will increase.

- *Site specific*. Some hydrogen markets are unmovable. For example, hydrogen for aircraft must be delivered to airports. In contrast, refineries that require large quantities of hydrogen are built where there are low-cost sources of hydrogen. Today, most hydrogen is made from natural gas; thus, refineries that require large quantities of hydrogen are located near low-cost sources of natural gas. For site-specific hydrogen applications, alternative methods of hydrogen production become competitive when their cost is lower than that from natural gas at the specific location.

- *User size*. If a single large hydrogen consumer uses all the hydrogen from a production facility, development of such a facility is simple. However, if many customers are needed to consume the hydrogen from a production facility, major infrastructure elements (pipelines, etc.) are required to deliver the hydrogen as well as the added difficulty of matching production to demand. Markets with many small users are more difficult to commercialize.

- *Steady-state*. Some applications are constant users of hydrogen, while others require variable delivery.

- *Storage and distribution*. Different applications have very different needs for a supporting hydrogen storage and distribution system.

## 3. Descriptions of Markets

### 3.1 Liquid Fuels

About 40% of the U.S. energy demand is met by oil that is converted primarily to liquid fuels. Today's transportation system depends upon liquid fuels (gasoline, diesel, and jet) because of their high energy density by weight and volume and their ease of use. Liquid fuels can be made from hydrogen and any source of carbon (crude oil, heavy crude oil, tar sands, coal, biomass, and atmospheric carbon dioxide). Liquid fuels are typically hydrocarbons that have ratios of hydrogen to carbon of 1.5 to 2. Gasoline, diesel, and jet fuels are characterized by their performance in engines. No fixed hydrogen-to-carbon ratio is associated with each fuel.

**Table 1: Markets for Hydrogen**

| Market | Product | Oxygen Use | Heat Use | Existing Market | Site Specific | User Size | Steady State | Storage & Distribution |
|---|---|---|---|---|---|---|---|---|
| Refineries | Liquid Fuel | No | Maybe | Yes | No | Large | Yes | No |
| Heavy Oil and Tar Sands | Liquid Fuel | Maybe | Yes | Yes | Yes | Large | Yes | No |
| Coal Liquefaction | Liquid Fuel | Yes | Yes | Yes | Yes | Large | Yes | No |
| Atmospheric Liquid Fuels | Liquid Fuel | No | Maybe | No | No | Large | Yes | No |
| Biomass Fuel | Liquid Fuel | No | Maybe | No | Yes | Medium | Maybe | Yes |
| Carbon Dioxide Recycle Fuel | Liquid Fuel | No | No | No | Yes | Medium | Yes | Limited Distribution |
| Chemical | Chemicals | No | Maybe | Yes | No | Variable | Yes | No |
| PENS[a] | Peak Electricity | Yes | Maybe | No | Yes | Large | Yes | Storage |
| Iron | Iron | No | Yes | Yes | Yes | Large | Yes | No |
| Aircraft | $H_2$ Fuel | No | No | No | Yes | Medium | No | Yes |
| Hydrogen Direct Transportation | $H_2$ Fuel | No | No | No | Yes | Small | No | Yes |

[a]Peak electricity nuclear system.

The world is rapidly exhausting its resources (Fig. 1) of the light crude oils (*Nature* 2004) used to make liquid fuels. These crude oils are the easiest to recover, have the lowest costs of recovery, and have the highest market prices. Consequently, for a century, oil companies have preferentially explored for and recovered these crude oils. Liquid fuels will increasingly be produced from other feedstocks with lower hydrogen-to-carbon ratios. In a refinery, these lower-grade feeds are converted to liquid fuels by adjusting the hydrogen-to-carbon ratio of the feedstock. For example, consider a heavy crude oil with a hydrogen-to-carbon ratio of slightly above 1. The hydrogen-to-carbon ratio of this feed can be converted to a liquid fuel by adding hydrogen (hydrocracking) or removing carbon (thermal cracking). The carbon that is removed is ultimately released to the atmosphere as carbon dioxide. Today, refineries use varying amounts of hydrocracking and thermal cracking for liquid-fuel production, depending upon hydrogen costs. If hydrogen is inexpensive, hydrogen will be added. If hydrogen is expensive, large quantities of carbon dioxide may be produced per unit of liquid fuel.

If current technologies are used, the carbon dioxide emissions per unit of liquid-fuel production will likely increase dramatically in the next several decades as the hydrogen-to-carbon ratio of the feedstocks decreases (Fig. 2). Ultimately, in a business-as-usual scenario, the carbon dioxide emissions from the facilities producing the liquid fuels may exceed the carbon dioxide emissions from the actual burning of the liquid fuels in transport vehicles. *Alternatively, if economic hydrogen is available from non-greenhouse-emitting sources and the energy for the fuel processing does not release greenhouse gases to the atmosphere, the atmospheric carbon dioxide emissions from liquid-fuel production per unit of liquid fuel and the net atmospheric carbon dioxide emissions from the vehicles burning liquid fuels can drop dramatically—in principle, to zero.* In the extreme cases, the demand for hydrogen for liquid-fuel production approximately equals the energy content of all the liquid fuels we use today. The hydrogen demand as a function of feedstock is described herein.

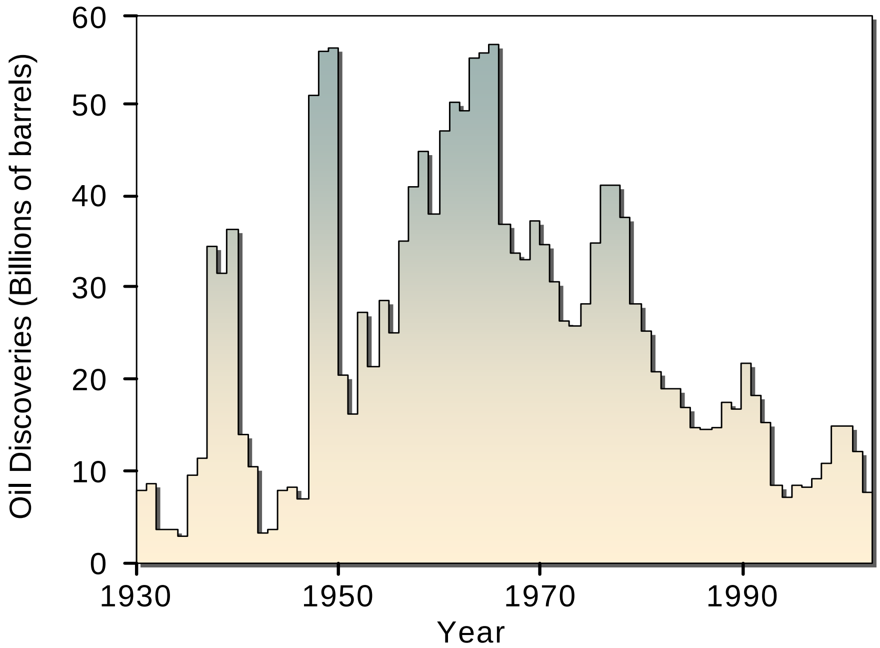


**Fig. 1.  Rate of discovery of conventional crude oils vs time.**

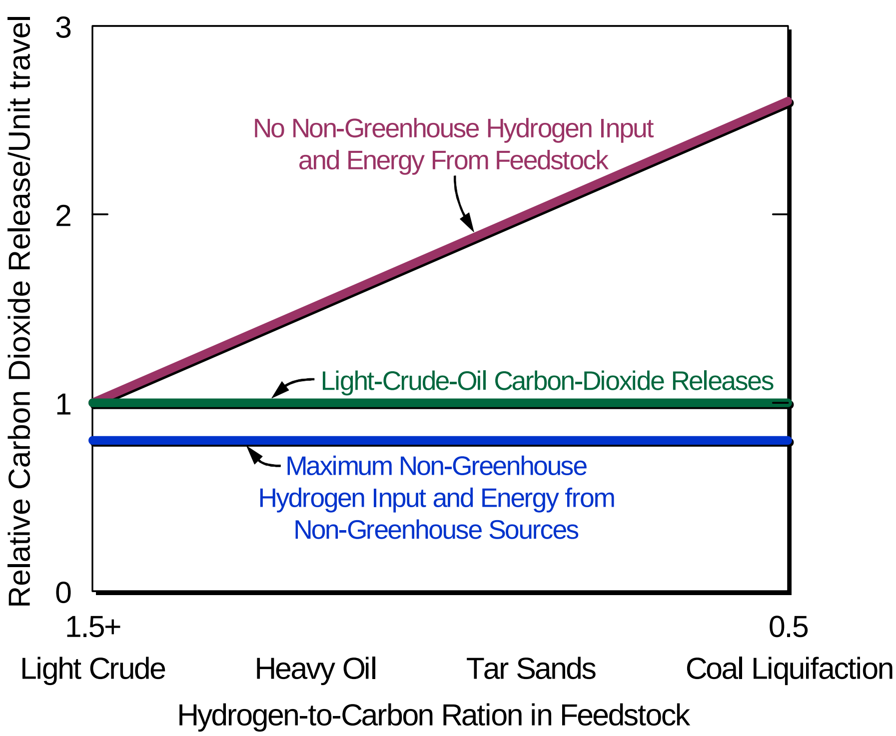


**Fig. 2.  Liquid-fuel carbon-dioxide production per vehicle mile vs feedstock, hydrogen source, and process energy source.**

### 3.1.1 Refineries

Typical refineries that convert light crude oil to liquid fuels are hydrogen neutral, neither consuming nor producing hydrogen. However, if low-cost hydrogen were available or there were penalties for carbon dioxide releases to the environment, the hydrogen-to-carbon ratio of fuels could be increased toward a maximum hydrogen-to-carbon ratio of ~2. In effect, the quantity (energy content) of liquid fuels produced per unit of crude oil or the equivalent transportation service provided per unit of crude oil is increased by 10 to 20%.

### 3.1.2 Heavy Oil and Tar Sands

Many experts believe that conventional oil production will peak in this decade and then decrease. The shortfalls in production are likely to be initially offset by conversion of heavy oils, tar sands, and other low-grade hydrocarbon deposits to liquid fuels (Williams 2003). The amount of synthetic crude oil that can be produced from these low-grade deposits far exceeds those of all conventional oil deposits combined. Massive amounts of hydrogen are required to convert these semiliquid, semisolid materials into gasoline. For example, the hydrogen-to-carbon ratio of tar sands is about 1, a value that must be raised to between 1.5 and 2 to convert the tar sands to gasoline.

Because of the imminent decline in conventional crude oils, the major oil companies of the world are rapidly expanding their facilities that convert these low-grade reserves into oil. Some perspective on the scale of operations can be obtained by examining the Alberta, Canada, tar sands developments. Production is being raised from its current level of 500,000 barrels/day of synthetic crude oil to 2.5 million barrels/day by 2010. Since 1996, $23 billion has been invested to increase production. An additional $37 billion in new plants and expansions has been announced. Most of the new world-class hydrogen plants are being built to support these facilities. If these tar-sand deposits are fully developed and natural gas is used to produce the required heat and hydrogen, the natural gas requirements will be *2 to 3 times the total projected Canadian natural gas reserves*. The demand of heavy oil and tar sands facilities represents the primary factor in the current growth in demand for hydrogen. This demand for hydrogen, and the resultant demand for natural gas to make the hydrogen, is beginning to have a serious impact on North American natural gas demand and prices.

### 3.1.3 Coal Liquefaction

The U.S. has some of the largest deposits of coal. Consequently, coal liquefaction is potentially a large long-term market for hydrogen to produce liquid fuels and minimize imports of oil.

In World War II, the Germans built large-scale facilities to convert coal to liquid fuels to replace imports of fuel. In 1955, South Africa started the first Sasol synthetic fuel plants that convert coal to liquid fuels using the German Fisher-Tropsch process. This complex was ultimately expanded to produce 100,000 barrels of oil per day. Following South Africa, in the 1980s New Zealand built a synthetic fuels plant using natural gas feed. This plant uses a two-step process that first produces methanol and then converts the methanol to gasoline.

There are two classes of coal liquefaction processes: direct and indirect. The direct processes (Beychok 1979) hydrogenate coal directly to produce liquids. The best of these processes have an efficiency of about 65%, which implies that about a third of the energy in the coal (and effectively one-third of the coal) is used to overcome these unavoidable process inefficiencies. Depending upon the coal, some faction of the remaining coal is used to make hydrogen; thus, perhaps a third of the carbon in the original coal is a component of the final liquid fuel.

The indirect processes convert carbon, oxygen, and water into synthesis gas—a mixture of hydrogen, CO, and $CO_2$. The newer synthetic fuel processes convert the synthesis gas into methanol ($CH_3OH$), which in turn is converted to liquid fuels. There are many variants of these processes. All existing commercial plants have used the indirect processes for a variety of reasons: the output of indirect processes is insensitive to the feedstock, the capital costs per unit of production are lower, the processes are technologically easier, and the products contain higher fractions of high-value liquid fuels. The process efficiency (Maiden 1988) for the New Zealand plant is estimated at 54% (ratio of energy value of liquid fuels to energy input).

These processes can be considered black boxes, carbon, oxygen, and water go into the process and liquid fuels and carbon dioxide exit the process. The carbon is used (1) as a chemical feedstock to provide the carbon in the liquid fuel and (2) as a fuel to provide energy for the process—including hydrogen production. At a fundamental level, the feed can be any carbon-containing material: coal, garbage, natural gas, etc.

The economics of liquid-fuel production require very large plants with massive demands for hydrogen and, in most cases, massive quantities of oxygen. The large German program in the 1970s to produce hydrogen using nuclear energy was to supply hydrogen and energy for coal liquefaction. (Germany has large coal resources but no liquid fuels.) The smaller nuclear hydrogen program in the United States in the 1970s had the same goal.

### 3.1.4 Direct Atmospheric Fuel Production

Liquid fuels can be made from water and carbon dioxide extracted from (1) the atmosphere or (2) the ocean. In this case, external sources of energy must be used. This energy can be in the form of electricity and hydrogen, where the hydrogen is used (1) as a feedstock to make the liquid fuels and (2) as an internal energy source to drive the process of producing the fuel. Given unlimited hydrogen, this option provides unlimited liquid fuel. No greenhouse impacts occur because the carbon dioxide is recycled from the atmosphere or seawater. There have been a series of studies on the technology for liquid-fuel production and the cost implications.

- *Navy*. The primary logistical demand for the Navy is the provision of liquid fuels for aircraft and ships. Aircraft carrier flight operations and fleet operations are limited by the capability of the oil tankers to provide fuel. This constraint can be eliminated by the use of a nuclear-powered tanker (Terry 1995) that manufactures jet fuel with nuclear hydrogen from seawater and carbon dioxide from the air or ocean.

- *Fusion energy complexes*. Engineering studies indicate that likely fusion energy plants may be very large [several thousand megawatts (electric) equivalent], even relative to the size of fission nuclear power plants. The very large energy output of these machines would create major difficulties in electrical transmission. These constraints would be eliminated if there were a large local market for that energy such as the production of liquid fuels (Fillo, Powell, and Steinberg, 1981). A series of studies were done to evaluate alternative liquid fuels production with the carbon from atmospheric carbon dioxide.

Most of these studies have assumed that the hydrogen is produced through electrolysis. Detailed studies (Steinberg and Dang, 1975) have examined alternative methods for recovery of carbon dioxide from the atmosphere and ocean. The generally recommended atmospheric-carbon-dioxide-recovery method is the use of aqueous potassium carbonate ($K_2CO_3$) solution for absorption and stripping of atmospheric carbon dioxide. About 80% of the total energy input required to produce the liquid fuel is used in the processes to produce hydrogen from water. The hydrogen is then used to produce the liquid fuel. If a high-temperature reactor is assumed to have 50% efficiency in the conversion of heat to electricity with hydrogen made by electrolysis, about 30% of the thermal energy produced by a nuclear reactor is converted into liquid fuels. This technology has several implications:

- *Liquid-fuel costs.* This option provides unlimited liquid fuels with no greenhouse impacts as long as the hydrogen and electricity come from non-greenhouse energy sources. If there is a non-greenhouse source of energy, it caps the potential costs of liquid fuels because the raw materials (water and atmosphere) are available in unlimited quantities.

- *Hydrogen economy*. From an economic perspective, this technology places an upper economic limit on the allowable costs for using hydrogen directly as a fuel compared with using liquid fuels—if there are constraints on net release of carbon dioxide to the atmosphere. About 80% of the energy for liquid-fuel production using carbon dioxide from the atmosphere or ocean is the cost of hydrogen manufacture. The other energy costs are associated with capturing carbon dioxide from the atmosphere and converting the carbon and hydrogen to liquid fuels. If the costs to distribute and use hydrogen directly as a fuel exceed those of liquid fuels, this technology defines an economic upper limit for the direct use of hydrogen for transportation before it becomes more economic to make liquid fuels from hydrogen and atmospheric carbon dioxide.

### 3.1.5 Biomass Conversion

Biomass today is used to produce liquid fuels such as alcohol by fermentation. This is potentially a non-greenhouse liquid-fuel source because the carbon dioxide used to make the biomass comes from the atmosphere. However, in a plant that converts biomass to liquid fuel, part of the carbon in the feed is converted to carbon dioxide by the biomass to provide the energy to keep the biomass alive. For example, the conversion of corn to ethanol results in roughly a third of the carbon from the original corn in the ethanol, one-third in the by-product animal feed, and one-third in the carbon dioxide released to the atmosphere. Biomass processing facilities are concentrated sources of carbon dioxide recovered from the atmosphere.

This carbon dioxide can be combined with hydrogen to produce liquid fuels. In effect, there is the potential to use biomass as a non-greenhouse-generating carbon source to make liquid fuels as well as an energy source. This type of option has been investigated by Bruce Energy Center of Ontario Hydro and Integrated Energy Development Corporation. The concept was to produce hydrogen through electrolysis of water using electricity from the Bruce Nuclear Generating Station in Tiverton, Ontario, Canada, and to collect carbon dioxide from an ethanol plant. The feeds would then be converted into liquid fuels and chemicals using existing technology (Gurbin and Talbot 1994). This type of liquids fuel production is distributed because of the cost to collect and transport biomass to a central fuel plant location.

### 3.1.6 Carbon-Dioxide Vehicle Recycle Systems

Liquid fuel systems that deliver hydrogen to the vehicle engines, capture the carbon dioxide on-board the vehicle, and recycle carbon dioxide, are being investigated in Japan (Kato et al., 2003). The vehicle is fueled with a liquid fuel and a calcium oxide (CaO) bed. The system contains the following components.

- *Vehicle steam reformer*. The CaO bed is used as a steam reformer where the liquid fuel is converted to hydrogen and carbon dioxide and the carbon dioxide reacts with the CaO to form solid calcium carbonate ($CaCO_3$). The reaction of the CaO and the $CO_2$ (1) is highly exothermic and provides the energy necessary to drive the highly endothermic stream reforming reaction to completion to maximize hydrogen production and (2) removes all the $CO_2$ and thus drives the equilibrium reactions to produce hydrogen rather than a mixture of $H_2$, CO, and $CO_2$.

- *Vehicle engine*. Fuel cells or an internal combustion engine powers the vehicle with hydrogen.

- *Fuel factory*. The $CaCO_3$ bed is returned to a fuel factory where hydrogen chemically reduces the $CaCO_3$ to CaO for recycle to vehicles and the recovered carbon dioxide is combined with hydrogen to produce new liquid fuel.

In this system, carbon is a recyclable hydrogen and energy storage mechanism between the fuel factory and the vehicle. Hydrogen enters the fuel factory and reappears inside the vehicle. Current estimates indicate that the volume and mass of this hydrogen fuel delivery system on-board the vehicle are less than other existing methods to deliver hydrogen to a vehicle. The low volume and mass of the fuel system aboard the vehicle is because energy is stored in two high energy-density forms: (1) the solid CaO reformer beds and (2) the liquid fuel. Most fuel factories would be near cities to minimize transport cost of solid CaO reformer beds. This system configuration implies distributed fuel factories requiring hydrogen—probably via pipeline.

### 3.2 Ammonia and Other Chemical Applications

Ammonia production (fertilizer) consumes about half the hydrogen produced today and is the primary chemical industry use of hydrogen. The market is growing slowly and is international. Ammonia is made where there is inexpensive natural gas that provides inexpensive hydrogen and shipped to the customer. Because of the increasing use of precision agriculture that has lowered the nitrogen fertilizer inputs per unit of food or biomass produced, large growth in demand for ammonia (and thus hydrogen) is not expected in this industry.

### 3.3 Energy Storage for Intermediate and Peak Electrical Production

The demand for electricity varies daily, weekly, and seasonally. As a result, the market price of electricity varies by an order of magnitude as a function of time. To meet this demand, the utilities buy lower-capital-cost peaking power units, typically gas turbines that burn natural gas. In addition, utilities have developed storage devices so that they can buy electricity during times of low demand and low cost and sell the electricity during times of high demand and high prices.

For example, the Tennessee Valley Authority (TVA) operates the Raccoon Mountain pumped-hydro storage facility. This facility pumps water up the mountain when low-cost power is available. During times of high power demand and high-priced electricity, the water direction is reversed to produce electricity. This facility has a rated capacity of 1530 MW(e). Another example is the Duke Power Koewee-Jocasse Project where water is pumped from Lake Koewee to Lake Jocasse during times of low power demand and the water is released through turbines to generate electricity during times of peak power demand.

The variability of the price of electricity creates the potential for a large hydrogen market aimed at producing electrical power at those times of day when the price of electricity is at its maximum. A *peak electricity nuclear system* (PENS) using nuclear hydrogen (Forsberg 2005) has been proposed that consists of three components (Fig. 3):

- *Hydrogen production*. A nuclear power plant with an associated hydrogen and oxygen (optional) production plant to produce hydrogen and oxygen at a constant rate to minimize the production costs.

- *Hydrogen storage*. One or more underground facilities for the low-cost storage of hydrogen and oxygen (optional). Underground caverns, depleted oil and gas fields, and aquifers are the traditional approaches to the low-cost storage of natural gas to meet seasonally variable natural gas demand.

About 8 trillion cubic feet of natural gas can be stored in existing underground facilities in the United States (half of this quantity as a buffer gas to maintain high pipeline pressures). In countries such as Great Britain, salt caverns have been used for many decades for the low-cost storage of hydrogen. Underground storage is the only known low-cost technology for storing compressed gases; however, the economics demand very large facilities.

- *Peak electric production.* Large banks of fuel cells convert hydrogen to electricity during periods of high demand for electrical power and associated high prices for electricity. For every megawatt of steady-state hydrogen production from the nuclear reactor, there would be several megawatts of fuel cells. While the reactor produces hydrogen at a constant rate, the fuel-cell electrical production is highly variable—from zero to many times the rate of energy production from the reactor when the price of electricity is high. The fuel cells may be placed at the reactor site. As an alternative, to reduce electrical grid requirements, hydrogen pipelines may be built around major cities, with large fuel cell facilities located at junctions where the pipeline crosses long-distance transmission lines.

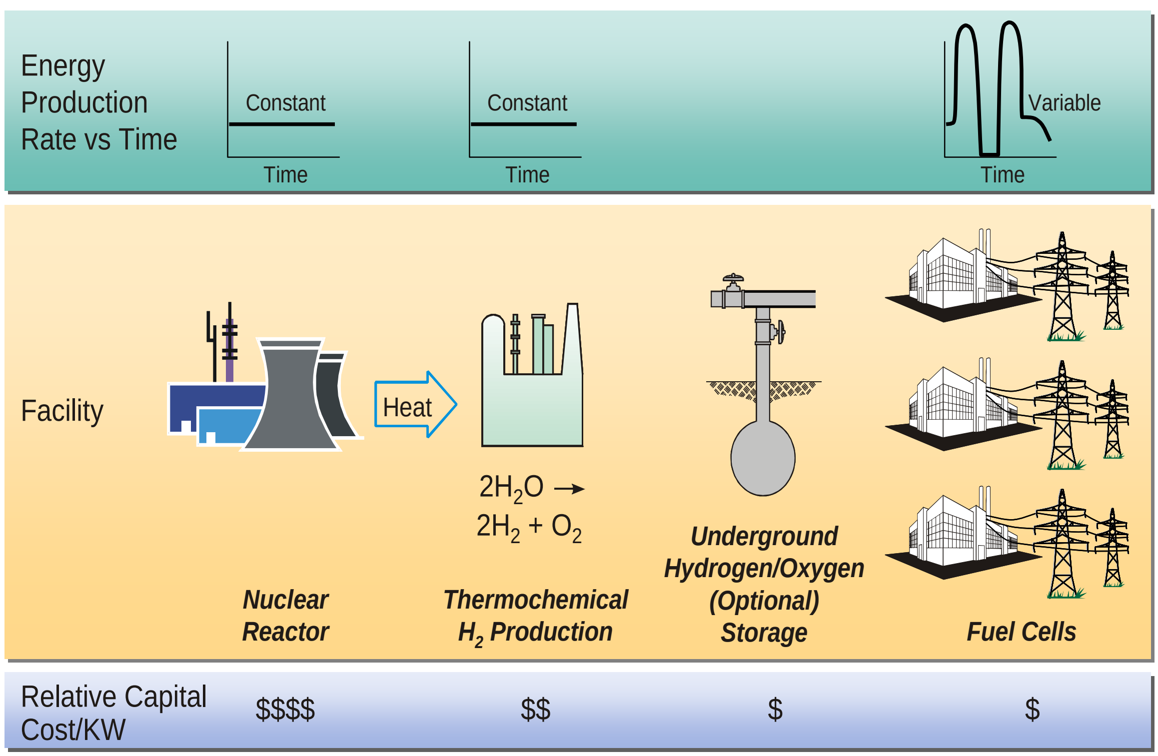


**Fig. 3. Peak Electricity Nuclear System using nuclear hydrogen**.

The economic feasibility of PENS is based on projected costs and efficiencies of fuel cells. The goal of fuel cell developers is to reduce the capital cost for hydrogen fuel cells to <$100/kW(e) with efficiencies of about 70%, compared with costs of $500/kWe for gas-turbine plants burning natural gas with efficiencies of about 50%. This use of fuel cells allows PENS to have a very large capacity to produce peak electrical power compared with the steady-state output of the reactor. The capital costs of fuel cells per kilowatt electric may be further reduced by the use of oxygen rather than air. Hydrogen is produced at a constant rate to minimize hydrogen production costs. However, but the ultimate product, electricity, is sold at times of peak demand for premium prices.

PENS is a stand-alone facility, like the TVA Raccoon Mountain project. It is not dependent on the outside market for hydrogen. Should another demand for hydrogen exist, however, the hydrogen can be sold at the plant gate. In the United States, the potential market exceeds 100 GW(e) equivalent on a steady-state basis if the peak and much of the intermediate load are replaced by PENS. There are several variants of this concept using various hydrogen production and electricity production technologies—all dependent upon the low-cost storage of hydrogen and oxygen on a large scale.

### 3.6 Direct Reduction of Iron Ore

In the production processes for converting iron ores into iron and steel, carbon, primarily in the form of coke, has been traditionally used to reduce the iron oxides to iron metal. However, in the last several decades, there has been increasing production of iron using the direct reduction iron (DRI) process. In 1998, about 4% of the primary iron in the world was produced by the DRI process with rapid growth in iron production. In the DRI process, syngas (a mixture of hydrogen and carbon monoxide) made from natural gas is used to reduce iron ores to iron. The major chemical reactions are as follows:

$$Fe_3O_4 + CO \rightarrow 3FeO + CO_2$$

$$Fe_3O_4 + H_2 \rightarrow 3FeO + H_2O$$

$$FeO + CO \rightarrow Fe + CO_2$$

$$FeO + H_2 \rightarrow Fe + H_2O$$

The DRI process has lower capital costs than alternative methods used to produce iron but requires a low-cost source of hydrogen. The primary market for DRI is to provide a purified iron feed for electric arc furnaces (EAFs) that produce various steel products. EAFs have lower capital costs than traditional steel mills and are environmentally cleaner operations than blast furnaces. Over a third of the world's steel production uses this process. It is predicted that by 2010 up to 45% of the world's steel may be made with EAFs. Historically, scrap metal has been the traditional feed for EAFs. However, there are two constraints: the availability of scrap metal and the various difficult-to-remove impurities (copper, nickel, chrome, molybdenum, etc.) that are present in the lower-grade scrap metal. Blending clean DRI-process iron with scrap metal dilutes the impurities below the level that affect product quality.

Iron production is a significant existing market for hydrogen. If low-cost hydrogen were available, the DRI process would replace other methods of iron production. The economics of DRI relative to other processes depend upon three factors.

- *Technological developments.* The continuing improvements in EAF technology in terms of reduced production costs and increased capabilities to produce higher-quality steel have expanded the market share of this technology. That creates the demand for more iron by the DRI process as traditional sources of scrap metal are exhausted.

- *Environmental protection*. Traditional steel processes use coal and generate large quantities of pollutants. Clean air requirements strongly affect the economics of these competing processes.

- *Hydrogen costs.* The process is used where there is low-cost natural gas for hydrogen production near iron deposits.

A variant of this option was studied in Japan between 1973 and 1980. The "Nuclear Steelmaking Project" conducted major engineering tests and designed a 500-MW(t) reactor. This project was the start of the Japanese high-temperature reactor program.

### 3.7 Aircraft

Liquid hydrogen has been considered for three types of aircraft applications: commercial jets, hypersonic jets, and electric airplanes.

*Commercial jets*. Commercial aircraft can be fueled with liquid hydrogen. The European Union (Airbus Deutschland GmbH 2003) funded a consortium of 35 partners from the aviation sector, led by Airbus Deutschland, to conduct a systems analysis of hydrogen-fueled aircraft—the CRYOPLANE project. This consortium examined a wide range of aircraft from business jets to large long-range aircraft such as the new jumbo Airbus A380. The key issue was to model the liquid-hydrogen fuel system. Per unit energy, liquid hydrogen has four times the volume of jet fuel; therefore, the fuel tanks must be four times larger. Analysis showed that because of the larger external surface area of the aircraft needed to accommodate the fuel tanks, the energy consumption would increase by 9 to 14%. Overall operating costs would increase by 4 to 5% based on fuel alone. It was also concluded that the engines would be equally efficient, the aircraft would have safety equivalent to that of current aircraft, and the environmental impacts would be substantially less (i.e., no carbon dioxide emissions). Further development is needed; however, such an aircraft system could be implemented within 15 to 20 years of a decision to use hydrogen as a fuel.

*Hypersonic jets*. Hypersonic aircraft require liquid-hydrogen fuel. The air velocity through a ram jet requires a fuel with a very fast flame temperature and diffusion rate to ensure combustion within the engine. Hydrogen is the only option. Liquid hydrogen is also used to provide active cooling to leading aircraft surfaces to avoid melting. This market depends upon the development of these jets.

*Electric aircraft*. Aircraft can use electric motors and hydrogen fuel cells to power propellers. These systems have potentially very high efficiencies compared with alternative propulsion systems. If weight and cost can be sufficiently reduced, liquid hydrogen becomes a preferred fuel. The viability of such aircraft depends upon technological progress in fuel cells and related systems.

### 3.8 Hydrogen Auto and Truck Transport System

Hydrogen is proposed as the ultimate transport fuel for cars, trucks, and buses. Recent reports (U.S. National Research Council 2004) describe the various scenarios. This can be considered the ultimate end state of hydrogen development if the various technical barriers are eliminated. Some of the hydrogen transport scenarios assume on-board conversion of liquids to hydrogen. Those scenarios are similar to the liquid-fuel scenarios described earlier, except that there would be a strong emphasis to maximize the hydrogen content of the liquid fuel. Other scenarios assume hydrogen as the stored fuel.

## 4. Conclusions

The future will demand very large quantities of hydrogen; however, it is unclear whether that hydrogen will be used in vehicles or to produce a variety of liquid fuels at large industrial complexes. Constraints on the release of carbon dioxide to the environment would create massive added demands for hydrogen using technologies that do not release carbon dioxide to the environment. The hydrogen demand could equal 40% of the total energy demand if it replaces oil. Many pathways to a hydrogen future involve increasing uses of hydrogen for making liquid fuels from different feedstocks, meeting peak electrical power demands, and producing steel. As a consequence, the transition to a hydrogen economy may be facilitated if the first users are large industrial companies with sizable demands for hydrogen and minimal need for large supporting hydrogen infrastructures.

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