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A COMBINED NUCLEAR AND HYDROGEN ENERGY ECONOMY - A LONG TERM SOLUTION TO THE WORLD'S ENERGY PROBLEM*

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Abstract

Future demand for the world's supply of carbon-based fuels eventually will exhaust this supply until their use becomes economically infeasible. Hydrogen, which is virtually inexhaustable in the form of water, could be substituted for natural gas and petroleum-based fuels for industrial and residential heating and for transportation. Nuclear energy, either fusion or fission, would be the primary energy source. Thermal energy from the nuclear heat source would be converted to electrical energy in a conventional heat-engine cycle. Hydrogen could be produced from water by a cyclic thermochemical process. Gaseous hydrogen for industrial and residential heat would be transported in a high-pressure pipeline system. Liquid hydrogen stored in metal hydrides could be used for transportation fuels. The basis of this future energy economy would be energy complexes of two types. Large plants, located off shore would produce hydrogen and electricity with desalted water as a byproduct. Smaller plants, located inland near urban centers, would produce primarily electricity and hydrogen.

I. Introduction

Heretofore, we in the U.S. have had an abundance of cheap, naturally occurring energy sources, and through the unabated use of these sources, we now find ourselves at what some call an "energy crisis". Upon scrutiny of the many projections of the supply and demand of these energy sources, two conclusions become evident:

1. The U.S. demand for hydrocarbon fuels, particularly natural gas, can only be supplied by an ever increasing amount from sources other than our current naturally occurring sources. Projections vary quantitatively, but it is generally agreed that a major fraction of the demand will be supplied by other sources within tens of years.

2. Eventually, the world's supply of naturally occurring carbon based fuels will be depleted, simply because these fuels are used much faster than they are replaced by natural processes. Photosynthetic and acceptable methods of synthesizing fossil fuels from CO_2 are being explored, but no method has yet been proven feasible that could significantly close the gap between the fractions of a second to burn carbon and the millions of years to naturally reduce the combustion product, CO_2, to a usable fuel. Of course, projections of "how long do we have" are even more uncertain for the ultimate depletion of fossil fuels. Therefore, in the long run, it is imperative that a substitute be found for carbon-based fuels.

The most important observation of the projections is that the cost of primary fossil fuels must increase because the deficit between demand and production can only be supplied by either importing natural gas and crude oil, discovering new natural reserves of these fuels, or synthesizing these fuels from the more abundant natural reserve of coal. We will assume that importing fuels is unacceptable in the long run because of national security implications and the resulting deficit balance of payments, and that discovering new reserves merely extends the time before importation or synthesization becomes significant. Therefore we will assume that synthesizing fuels from coal will be necessary if we are to continue our carbon-based fuel economy.

Because the ratio of hydrogen atoms to carbon atoms in coal is about one, synthetic substitutes for natural gas and crude oil made from coal require a source of hydrogen. For synthetic crude oil a minimum of one extra hydrogen atom is needed to form the straight-chain saturated hydrocarbon, $C_nH_{(2n+2)}$, and for methane (CH_4), the principal constituent of natural gas, at least three extra hydrogen atoms are needed.

Therefore, a technically and economically feasible means of producing hydrogen should be useful for synthesizing hydrocarbon fuels, and, more importantly, hydrogen may better serve world energy needs than carbon-based fuels. The supply of hydrogen is virtually unlimited in the form of sea water and is essentially replaced as water vapor upon combustion. The switch to hydrogen for energy needs would return the carbon atom to its natural role in the biological life cycle and would provide for the use of the remaining supply of fossil fuels as feedstock in the expanding organic chemical industry.

The use of nuclear fuel as a primary energy source has already proven economically competitive for the production of electricity, principally because of the low cost of nuclear fuel. Although the fuel cost for uranium-burning reactors will increase as rich-ore uranium deposits are depleted, fossil fuel costs are expected to increase more

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* Work performed under the auspices of the U.S. Atomic Energy Commission

rapidly. Furthermore, with the development of the breeder reactor, nuclear fuel costs will stabilize because of the vast supply of natural uranium.

Whether hydrogen is used for hydrocarbon fuel synthesis or as a fuel itself, large production facilities will be needed because of the large quantities demanded along with the economic factors favoring large production plants. For efficient dissociation of hydrogen from water, a high-temperature energy source will be needed. With further development of the high-temperature gas-cooled reactor (HTGR) as a primary nuclear energy source, a plant complex producing hydrogen and electricity could be developed for future long-range energy needs.

II. The Need For New Energy Sources

Future demand for the world's premium oil and natural gas fuels eventually will exhaust the supply until their use as ordinary fuels becomes infeasible. As this happens the large scale use of the world's coal resource, of which the U.S. has a particularly plentiful supply, will become increasingly important. Major air pollution resulting from the use of this coal can be avoided by solvent refining, liquefaction, or gasification of the coal to produce synthetic, clean premium fuel substitutes. However, land despoilation resulting from the surface mining and ash residue of this coal will mitigate increasingly against large scale use, particularly as the more choice concentrations are exhausted and thinner veins and poorer grades are exploited. This will lead to a more concerted effort to make efficient use of the coal, which is now only a very secondary consideration, and to the search for new, substitute fuels. This picture is put into perspective in Table I in which the U.S. reserve, including Alaska, is listed for various fuels along with projected U.S. energy requirements. The ranges of values given for the oil and gas resource reflect real uncertainties that exist as to the actual domestic resource in accordance with various predictions which have been made. The range of values for coal reflect the accessibility and thus the cost of this relatively well mapped resource. The lower value pertains to presently known formations of comparable thickness and depth to those presently being mined. The larger value reflects total remaining resources to a depth of 6000 ft and is clearly not actually recoverable. The range of values given for uranium reflect a variation in price of U_3O_8 from $15/lb to $50/lb. Uranium reserves are not well known and these estimates are probably pessimistic. Thorium reserves are less critical than uranium reserves and are therefore not listed.

The mounting intense pressure of the U.S. energy problem will result in the discovery and utilization of nearly all of the oil and gas reserves to furnish the bulk of energy demand for many years. However, a major energy deficit is inevitable by 1980, if the lower resource estimates are correct, and by 2000 if the higher resource estimates are correct. The nation will look increasingly to coal and nuclear energy to correct this deficit. These will supply energy primarily to generate electrical power while the oil and gas will be used primarily for heating industrial and transportation uses. The major problem to appear in the 1990-2000 time period will be the fact that electricity cannot readily be substituted for these latter needs due to reasons of practicality and cost. Production of synthetic fuels from coal will receive great emphasis, however this is awkward and inefficient as discussed previously and requires massive supplies of hydrogen. A method of producing a substitute fuel using a nuclear heat source is desired to augment production of synthetic fuels from coal during the 1990-2000 transition period and ultimately as a source of nearly all non-electrical energy. If this substitute fuel is hydrogen then it can serve multiple functions - as a primary fuel, as a chemical feedstock for efficient coal liquefaction and gasification, ammonia production, metal ore reduction, and ultimately as an efficient source of electricity using fuel cells. The hydrogen itself is not an energy resource, but rather a particularly convenient intermediate medium for storing and transporting energy. The energy resource is nuclear fuel.

Table I

U.S. Domestic Energy Needs and Resources(1)

		10^{15} Btu
Demand:	(1970-1985)	1340
	(1985-2000)	2170
	(2000-2020)	4650
Oil	(1970)	1230-2300
Natural gas	(1970)	870-1530
Coal	(1970), total	3000-64400
33% utilization, premium veins		1000
Uranium	(1970)	
LWR, HTGR; with recycle[a]		1042-6200
Fast breeders[b] (1/3 of fuel burned)		33600-200000

[a] 310×10^6 Btu/lb U_3O_8

[b] 10000×10^6 Btu/lb U_3O_8

Unless substantial increases in uranium reserves are discovered then some reliance on breeder reactors will be desired to avoid the excessive land despoliation which would be associated with recovery of very low grade uranium ore. A minor fraction of breeder reactors can supply the fuel required for LWR or HTGR converter reactors in order to obtain a net high utilization of the total uranium and thorium mined. An alternative may be the utilization of uranium from sea water.

If fusion energy is successfully developed, then the same arguments for the need for hydrogen generation will apply. Fusion power is presently envisioned primarily as a heat source for electrical power. If fusion energy can be used to generate hydrogen then application of the same techniques with fusion energy should be straightforward. However the U.S. should not rely on development of a fusion source energy, due to the present uncertainty as to even the basic feasibility of the technology. Development of other energy resources, notably solar and geothermal, is not likely to change the predicted scenario appreciably, since these are envisioned as generally local and specialized in application and small in total output compared to the total energy demand.

III. The Combined Nuclear And Hydrogen Energy Economy

Methods of Hydrogen Production

Unfortunately, the only present means of commercially producing hydrogen in the U.S. is by steam reforming of methane from natural gas or partial oxidation of crude oil. Hydrogen is also produced by electrolytic decomposition of water, but the higher cost of this method restricts this method to areas such as in Canada and Norway, where electricity is cheap and there is no natural gas source. The total hydrogen production for ammonia and refined petroleum products consumes about one percent of the natural gas produced as an energy source.

Obviously we cannot afford to produce hydrogen from methane either for a primary fuel or to make synthetic fuels from coal. Therefore, at the present time, the only commercial method available is the electrolysis of water.

Because the energy cost of producing hydrogen by electrolysis is determined in part by the cost of electricity, the energy cost of electrolytic hydrogen will always be higher than that of electricity. Therefore, presuming that economics will continue to govern the choice of primary fuels, hydrogen produced by electrolysis will not supplant fossil fuels (or used to produce synthetic fuels) as long as it is economic to use fossil fuels to produce electricity. But, as stated previously, nuclear fuel is now competitive with fossil fuels for producing electricity and nuclear fuel usage will be increasing while fossil fuel usage will decline during the future growth of the electric power industry. However, the major fraction of the production cost of electricity is in the plant capital cost, so that even if the nuclear fuel cost were zero, the cost of electricity would still be relatively high. For example, the capital cost portion of today's nuclear power plants is ~130¢/10^6 Btu (3 mil/kwh), compared with, e.g. 60¢/10^6 Btu, high fossil fuel costs for today. Because the capital cost of electrolysis plants is relatively low, ~30-40¢/10^6 Btu, the hydrogen production cost would then primarily depend upon the cost of electricity. Therefore, the cost of synthetic fuels would have to approximately triple before hydrogen produced by electrolysis would become competitive as a fuel.

Clearly, a new method for producing hydrogen from water must be found to reduce the hydrogen production cost. The most promising method currently under consideration is a cyclic thermochemical process where the energy to separate hydrogen from water is in the form of heat. Such a chemical cycle consists of two or more steps, proceeding in principle as follows:

$$MO_X + H_2O \rightarrow MO_{X+1} + H_2 \qquad (1)$$

$$MO_{X+1} + (\text{heat}) \rightarrow MO_X + 1/2\ O_2 \qquad (2)$$

where M is a metal anion or complex radical. The ideal thermal efficiency of the above cycle is:

$$\eta = \frac{\Delta H^o}{\Delta G^o} \; \frac{T_2 - T_1}{T_2}$$

where ΔH^o and ΔG^o are respectively the heat and work for the dissociation of water at standard temperature (25°C) and pressure (1 atm) and T_1 and T_2 are respectively the temperatures of steps (1) and (2). For water this relation becomes $\eta = 1.2\ (T_2-T_1)/T_2$, therefore the maximum thermal efficiency is 20% higher than the carnot efficiency of a heat engine cycle at the same source and sink temperatures. To approach this efficiency the actual work (or free energy) for each step should be minimized, and the total work should be near zero. Because $\Delta G = \Delta H - T\Delta S$ (where ΔS = entropy change), these conditions may be approached if the step (1) entropy change is negative and the reaction exothermic at T_1, and, correspondingly, at step (2) the entropy change is positive and the reaction endothermic at T_2.

Several processes have been studied at Aachen University in West Germany, at the Establishment of Ispra, Euratom C.C.R. in Italy, and at General Electric, Gulf General Atomic Institute of Gas Technology, and Los Alamos Scientific Laboratory in the U.S. The process receiving the most study is Marchetti's Mark 1 cycle at the Establishment of Ispra.(2) This cycle is characterized by the following set of reactions.

$CaBr_2 + 2H_2O \rightarrow Ca(OH)_2 + 2HBr$ (1000 K)

$Hg + 2HBr \rightarrow HgBr_2 + H_2$ (320 K)

$HgBr_2 + Ca(OH)_2 \rightarrow CaBr_2 + HgO + H_2O$ (470 K)

$HgO \rightarrow Hg + 1/2\ O_2$ (870 K)

Marchetti claims a thermal efficiency of .55, although this claim is disputed by others. There are however three undisputed drawbacks to this cycle: (1) the chemicals are highly corrosive, which will make the process equipment expensive; (2) there is a large amount of materials circulated per unit of product; and (3) the use of large quantities of mercury introduces a potential toxicity hazard in case of leakage.

Other cycles generally have more than two steps and also involve the handling of corrosive materials such as Cl_2 or HCl. These cycles operate at maximum temperatures in the range of 1000 to 1300 K and have theoretical efficiencies in the range of 0.20 to 0.70. As yet, none of these cycles, including the Mark 1, have been proven experimentally, even at the bench-scale.

Within a decade both synthetic natural gas (SNG) and synthetic crude oil (Syncrude) could be produced from coal on a commercial scale at such a rate to supply a minor (but significant) fraction of the total demand for natural gas and refinery feedstock, provided current methods under development receive continued support. Today, some of these processes for SNG and Syncrude production are being tested on a pilot-plant scale (up to 70 ton coal/day).

All of the "coal gasification" processes currently under development require hydrogenation of the coal to obtain the CH_4 for SNG or the higher hydrocarbons ($> C_5$) for Syncrude, and all of these processes use the water gas reaction ($C + H_2O \rightarrow H_2 + CO$) as a basis for producing this hydrogen. For methane production the reaction chain is:

$$2C + 2H_2O \rightarrow 2H_2 + 2CO \quad \text{(water gas reaction)}$$
$$CO + H_2O \rightarrow H_2 + CO_2 \quad \text{(water gas shift)}$$
$$CO + 3H_2 \rightarrow CH_4 + H_2O \quad \text{(methanation)}$$

with a net reaction of:

$$2C + 2H_2O \rightarrow CH_4 + CO_2$$

Therefore, for every molecule of methane produced, two atoms of carbon are consumed and a molecule of CO_2 is produced as a useless by-product. This implies that if the natural gas supply is supplanted by producing SNG via these processes, the carbon source (in coal) will be consumed twice as fast than the carbon source in natural gas. Actually, for most coal gasification schemes, the energy required for the endothermic water gas reaction is also supplied by burning coal, resulting in even more coal (∿ 30%) consumed as feedstock.

All of these processes have a gasification step where there are differences in the gasification reactor configuration and the method of supplying the endothermic heat of the water gas reaction. There are also major differences in the amount of direct methane production by such schemes as preheating (prior to the injection of steam) or hydrogen enrichment of the steam. The raw gas product from the gasifier contains principally CO and H_2 with smaller quantities of CH_4, CO_2, H_2S, NH_3 and N_2 .

The other major steps, which are common in varying degrees to all processes, are coal preparation and raw gas upgrading. Coal preparation includes size reduction and pretreatment. Raw gas upgrading includes the water gas shift, acid gas (CO_2 and H_2S) removal, and methanation steps. The final product from raw gas upgrading contains > 90% CH_4 and has a higher heating value of 900-1000 Btu/SCF.

However, if an external source of hydrogen were available, the carbon in coal could be hydrogenated directly, at least theoretically, to any hydrocarbon desired without wasting carbon in producing CO_2. Furthermore, significant savings in the capital cost for SNG production should be possible by decreasing volume throughput in the gasifier and acid gas removal system, eliminating the shift reactor, and decreasing the methanation requirement to the CO level produced from the bound oxygen in the coal feedstock. Thermal balances are also more favorable for direct hydrogasification. There are no endothermic heat reactions. The $C + 2H_2 \rightarrow CH_4$ reaction is exothermic, producing ∿37% of the heat production in a methanation step. Although an exothermic reaction within a fluidized bed may introduce temperature control problems, it may be possible to "balance" the heat by injection of a material that will cause an endothermic reaction, e.g., a small amount of H_2O. If water is used, the product CO could be "methanated" in the same manner as in the "conventional" SNG production methods.

Apparently, experimental data on direct hydrogasification is not as prevalent as data on steam-carbon gasification, although some laboratory-scale data is available in the open literature.(3)(4)(5) However, in the HYGAS process (6) the steam feed to the gasifier is hydrogen-rich, therefore additional applicable data may come from the operation of this plant.

A process scheme that may be feasible using direct hydro-gasification is outlined in Fig. 1. This process uses the technology developed for the COED(7) and HYGAS processes that have been supported by the Office of Coal Research. The advantages of this scheme are as follows:

1. By using the multistage pyrolysis process prior to hydrogasification, highly volatile hydrocarbons bound in the coal feedstock are produced as well as a valuable refinery feedstock by hydrotreating of the evolved coal tars. Also the design of the hydrogasifier is essentially independent of the grade of coal feedstock because of the devolatilization during pyrolysis, i.e., the carbon content of the char feed to the hydrogasifier is higher and should be more uniform than that in the coal feed and such problems as agglomeration in fluidized-beds would not apply in the hydrogasifier.

2. With only exothermic reactions in the gasification and purification process, more flexibility exists for heat and process stream utilization. For example, the utilization of heat in hydrogasification stages becomes a variable rather than a requirement. As mentioned previously, possibly water recycled from the methanator could be injected to provide a net heat of reaction of near zero. Hydrogasification could be integrated into the pyrolysis stages to provide heat and hydrocarbon formation. The carbon content of char from the hydrogasifier is variable. Carbon depleted char could be "fired" by hydrogen or air to produce heat for conversion into electricity for plant electrical power requirements. The amount of methanation becomes variable - from the amount required to convert the CO produced as the result of bound oxygen in the coal feedstock to any amount depending on the economics of sizing methanation and steam-gasification with a recycle process water stream.

3. Probably the most important advantage is that the required technology development for hydrogasification is not very extensive for second generation coal gasification processes, particularly if the COED and HYGAS processes are selected for first generation plants. Presuming that hydrogen production costs will remain too high for direct hydrogasification to economically compete in the foreseeable future, direct hydrogasification would only be feasible for second generation processes anyway, so there is more time for a reasonable program for development of hydrogen production technology.

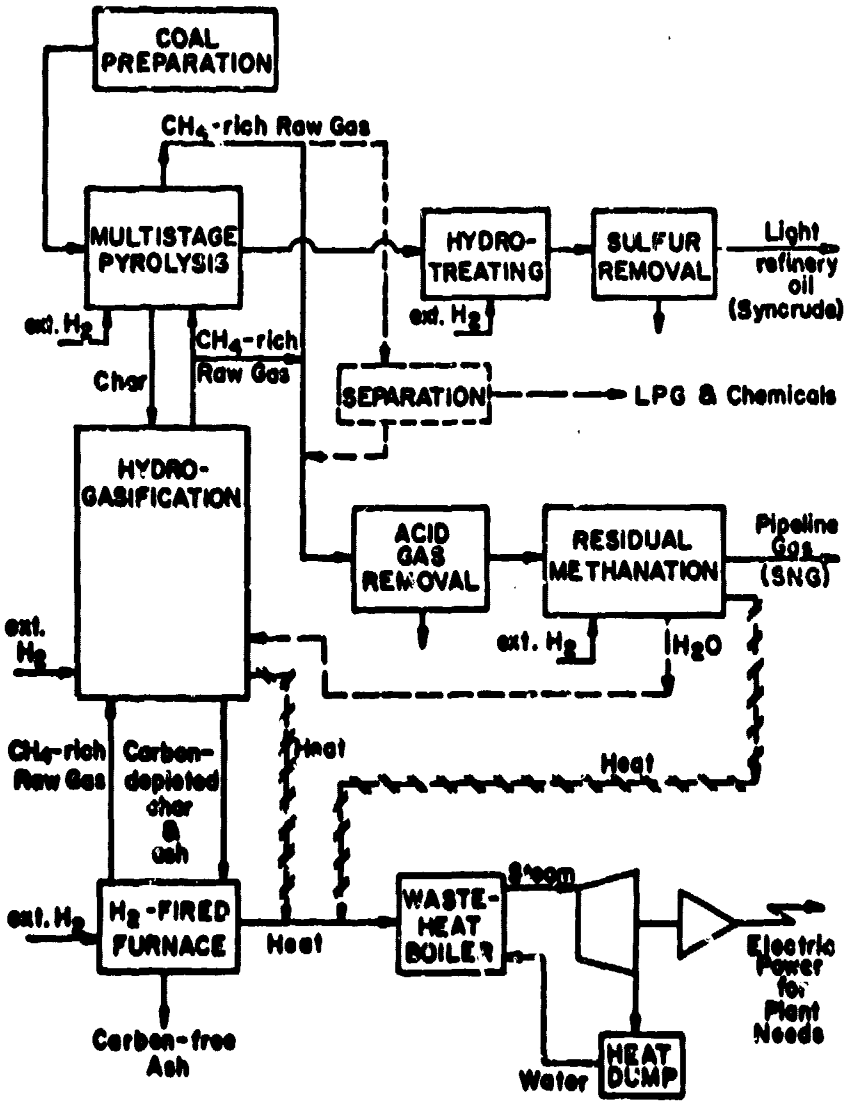

Fig. 1. Direct hydrogasification process (dashed lines represent options).

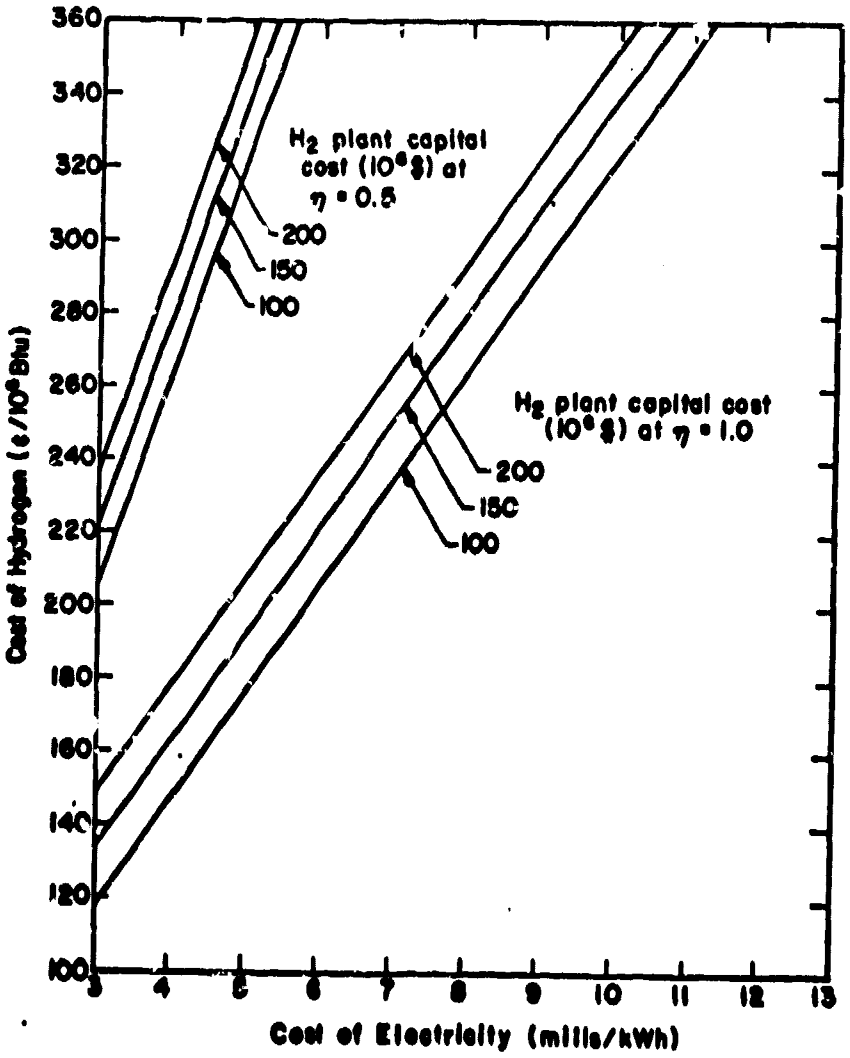

Fig. 2. Cost of producing electrolytic hydrogen as a function of electricity cost, hydrogen plant capital cost, and the electrical to hydrogen energy efficiency.

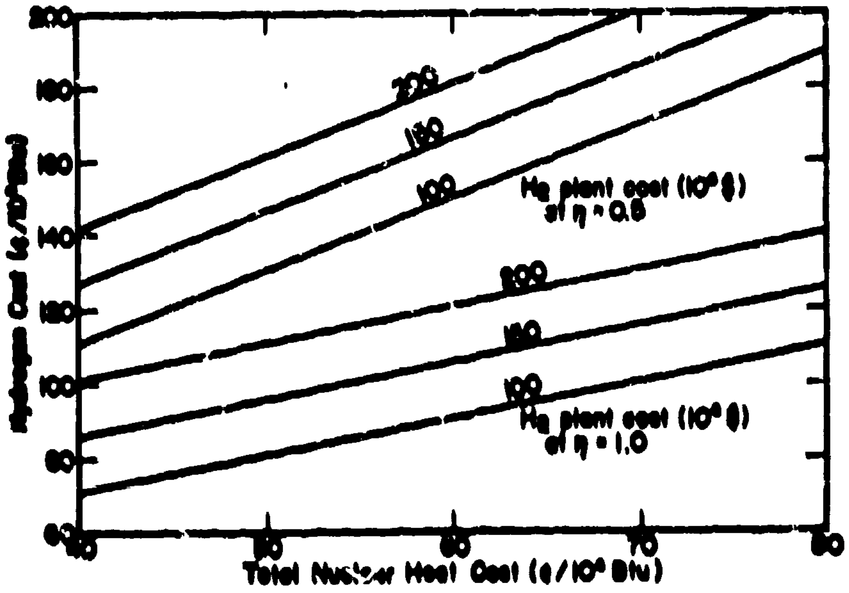

Fig. 3. Cost of producing thermochemical hydrogen as a function of nuclear heat cost, hydrogen plant capital cost, and thermal conversion efficiency.

Cost of Hydrogen

As previously stated, the high cost of electricity makes the use of electrolytic hydrogen as an energy source economically unattractive. This is further emphasized in Fig. 2, where the sensitivity of hydrogen cost to electricity cost is illustrated. These costs include the electricity cost, hydrogen plant capital cost, and the effect of electrical to hydrogen energy conversion efficiency (η). The plant capital cost is based on a plant capacity of 1300 ton/day with a plant service factor of 90% and is factored into production cost at a fixed annual capital charge of 16%. However, for thermochemical hydrogen production the electricity cost would be replaced by the nuclear heat cost, which will be a minor fraction of the electricity cost. For comparison with electrolytic hydrogen costs, the thermochemical hydrogen costs over a likely range of nuclear heat costs and based on the same capital costs as those for electrolysis are shown in Fig. 3. Although these costs may seem high compared to current fossil fuel costs, projections of future costs, listed in Table II, indicated that within approximately 30 yr hydrogen costs could become competitive with those of fossil fuels if fossil fuel costs increase at an expected rate of 4%.

TABLE II

Projection of Energy Production Costs(¢/10^6Btu)

Energy Source	1970	1975[a]	1995
Natural gas	30	60	131
Crude oil	60	70	153
Western coal	15	20	44
SNG(from western coal)	--	100[c]	136

a adjusted after deregulation

c 1980

For production of SNG by direct hydrogasification to be competitive with SNG produced by the water gas process, the hydrogen cost is afforded by savings from reduced coal consumption and savings in SNG plant cost. Such an estimate of hydrogen cost is shown in Fig. 4 with a Wyoming subbituminous B coal (HHV = 9420 Btu/lb) as feedstock for a 250(10)^6 SCF/day plant. Assuming a plant capital cost savings of 35%, the competitive hydrogen cost would be ~120¢/10^6Btu for the projected western coal cost in 1995 and an estimated capital cost of 300 (10)^6 $ for "conventional" 250(10)^6 SCF/day gasification plant.

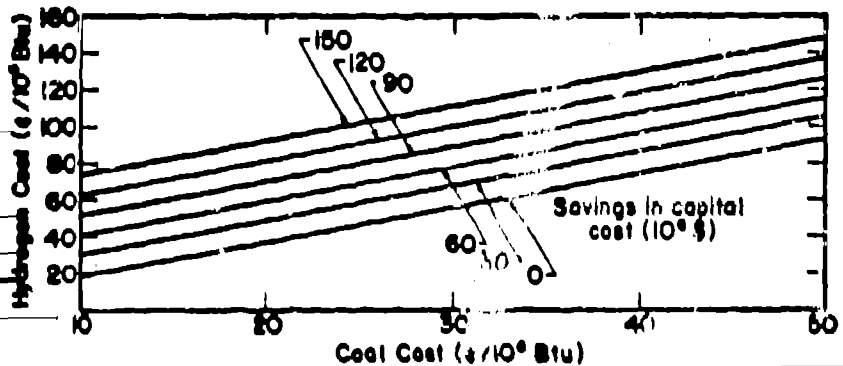

Fig. 4. Hydrogen production cost for competitive SNG production by direct hydrogasification

Although the foregoing cost estimates and projections are somewhat speculative, they do indicate a reasonable possibility that hydrogen costs could become competitive within approximately 20 years, which is a reasonable time to develop the technology for a thermochemical hydrogen production process.

The Energy Production Complex

For future energy needs we will assume that by the year 2020 the U.S. demand will be 3(10)^{17}Btu/yr corresponding to a capacity of (10)^{7}MW and that one-half of this demand is for electricity and one-half is for hydrogen as a transportable fuel. We will further assume that it will become economic to produce a fraction of the demand in large plants located off-shore along with production of desalted water from waste heat. Because approximately one-half of the U.S. population resides within 100 miles of the coastline, this fraction could be supplied with 100 plants (located 30 miles apart on the average) each producing 3(10)^{4}MW as shown in Fig. 5.

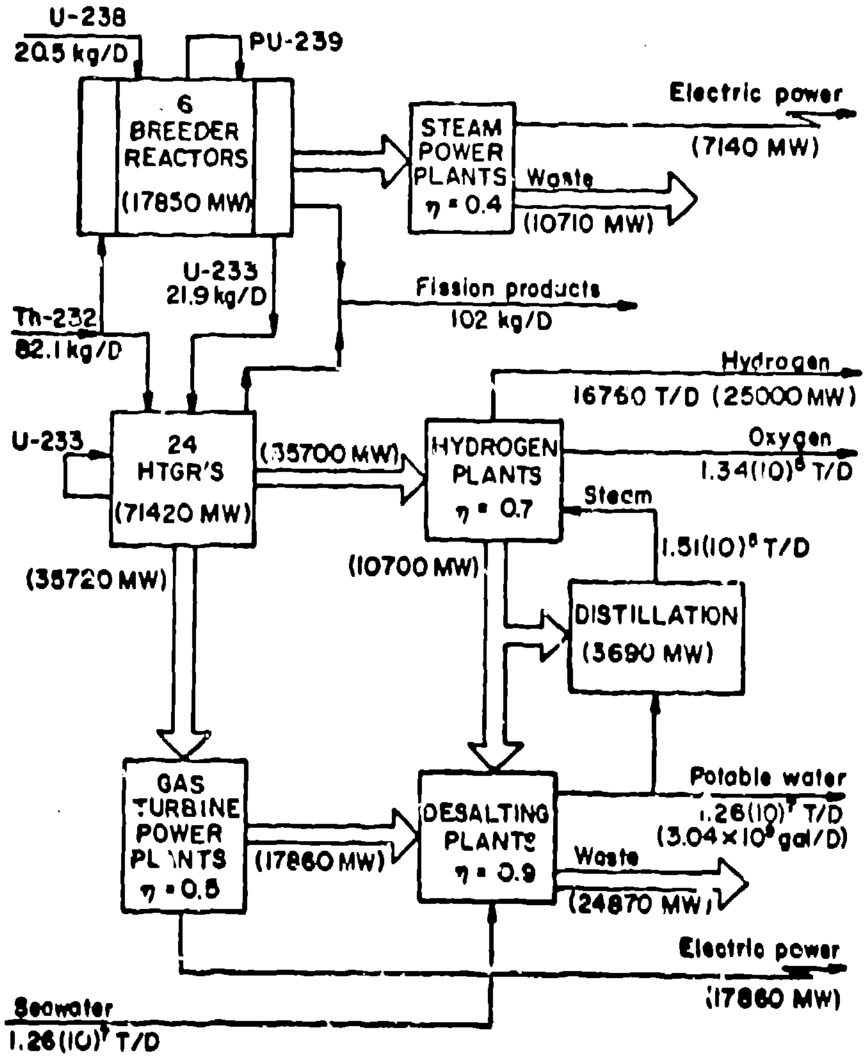

Fig. 5. Large off-shore energy complex.

Because controlled thermonuclear energy has not yet been proven scientifically feasible, we will assume the primary energy source is nuclear fission. To obtain a maximum of high-temperature energy, a combined fast breeder and thermal converter nuclear heat supply(8) is used. With a four to one ratio of converters (HTGR's) to breeders and a conversion ratio of 0.8 in the HTGR, the nuclear system will be self-sustaining with a Th-232 to U-238 feed ratio of four if the fast breeder plutonium breeding ratio is 1.0, supplying PU-239 only for itself and sufficient U-233 to sustain the HTGR's. Because of the high temperature, the significant advantage of the HTGR is that the rejection temperatures of the hydrogen and gas turbine plants can be high enough for water desalinization without drastically reducing the conversion efficiencies of hydrogen and electricity production. Assuming that HTGR fuels can be developed to produce gas temperatures up to ~1400 K (2060°F), the gas turbine plant efficiency could be 0.5 (at 2/3 of Carnot) with a heat rejection temperature of 367K (200°F) and the hydrogen plant efficiency could be 0.7 (at 0.9 of theoretical) with a heat rejection temperature of 450K (350°F).

In addition to the required demand for hydrogen and electricity, these plants (based on a production 14 lb/10^3Btu for a multi-effect evaporation plant would supply approximately the 1960 per capita consumption of water for irrigation, industrial, and municipal uses(9)

The only significant environmental impact of such large complexes would be the large amount of heat to reject. The majority of this heat could be stored in the desalted water (at a temperature < ~ 125°F) for subsequent dissipation over a large area by transportation, storage, and the irrigation needs. Part of the remaining fraction would be rejected to the ocean and the remainder could be rejected to the atmosphere by air-cooling.

The other one-half of the energy demand could be supplied by 1000 similar complexes at 1/10 capacity and located near urban population centers. The principal difference between these and the off-shore complexes is that the desalting plants would be replaced by a different heat rejection system and the energy ratio of converters-to-breeders would probably be decreased to approximately three to one. Because the hydrogen and gas turbine plant rejection temperatures can be relatively high, the major fraction of waste heat can be used to produce low-pressure process steam for residential heating and other industrial purposes.

IV. Hydrogen for Energy Distribution

Almost all attempts at a long term solution to the "energy crisis" involve the use of hydrogen in one form or another. Hydrogen becomes important not as a primary energy source but rather only as an energy transfer mechanism. Indeed in some instances the use of hydrogen may impose additional source energy requirements, e.g., liquefaction energy. Obviously in a broadly based "hydrogen economy" the portable or transportable hydrogen fuel may be needed in either the gaseous or liquid form or in the form of a metallic hydride.

Hydrogen gas supplied by pipeline can directly replace natural gas in almost all industrial and residential heating uses. Although extra energy conversions should be avoided, hydrogen could in special cases also be used to generate electricity by means of fuel cells. The distribution of hydrogen gas by pipeline is both feasible and may be economical(10). In proposing such an energy distribution system one must consider the lower energy density of hydrogen (325 Btu/ft^3 compared to 1000 Btu/ft^3 for natural gas) as well as its compensating lower density and viscosity. The combination of these factors results in the possibility of using existing natural gas pipelines for the distribution of hydrogen gas. However this use of existing natural gas pipelines will require consideration of material suitability and existing leakage. Appliances (jet size) will also have to be converted to hydrogen use. None of these tasks is insurmountable. Many U.S. cities used town-gas energy systems (containing up to 50% hydrogen) before converting to their present natural gas system(10). Since much of the objection to hydrogen is based on safety it is of interest to note that the city of Barcelona has halted its conversion to natural gas from town-gas due to safety problems encountered with the natural gas(11). An industrial pipeline system now distributes hydrogen gas over a network some 130 miles long in Germany(12).

Among the advantages of a hydrogen gas energy distribution system is its excellent energy storage capability. This would be especially valuable for a cyclical energy source such as solar energy or off-peak power from a constant power generating station. Advantages in the combustion of the hydrogen include the absence of carbon monoxide (no venting required) and the possibility of catalytic oxidation at low temperatures (perhaps as low as 100°C)(10).

Perhaps the most important contribution of hydrogen to future energy systems will lie in its use as a portable fuel in the field of transportation. The successful operation of internal combustion engines has been demonstrated to be both efficient and nearly nonpolluting on numerous occasions(13,14,15). Fuel storage methods to be considered are gaseous hydrogen (GH_2) at high pressure, liquid hydrogen (LH_2) and metallic hydrides. For air transportation using hydrogen, LH_2 is an obvious choice. This is probably also true for railroad and fleet vehicle operation. For privately operated automobiles the use of LH_2 is usually considered to be unsuitable either because of safety or because of exhorbitant losses due to boiloff, flashing etc. However, this conclusion is too hastily drawn and the method of fuel storage for automobiles is too important to allow the advantage of LH_2 to be so easily dismissed.

Storage of fuel as GH_2 does not appear at all attractive from the standpoint of tankage weight and volume. While metallic hydrides may prove to be the most attractive method for fuel storage they must still be demonstrated to be feasible from the standpoint of repeated regeneration, tankage cost and safety.

A preliminary investigation of the use of LH_2 for fuel storage for automobiles has indicated that its use is not as dangerous or wasteful as commonly believed(16). It is true that by assuming worst cases for all possible losses, a loss of 14% of total usage results. However, more intelligent operation can result in a considerable reduction of this loss and furthermore almost all hydrogen losses can be recovered as a gas for alternate uses. For example, the above mentioned total loss includes the boiloff loss from continuous venting from 10^8 automobiles which accounts for over six of the 14%. However, a 30 gallon tank with a 1% per day boiloff loss can be closed off for approximately one week before reaching the pressure where venting would be required(16). Under these circumstances only a small fraction of this loss would ever be realized.

The LH_2 tank required for an automobile is already close to present day state-of-the-art. With current production techniques a 30 gallon dewar tank with a 1% per day boiloff loss and sufficiently rugged to withstand most collisions would probably cost about $2500. However, application of mass production techniques would lower the cost drastically. (Estimates as low as $250 have been made(17).)

Distribution and refueling automobiles with LH_2 are the areas most in need of study and demonstration at this time. Current techniques for service station storage and over-the-road bulk transport are already satisfactory. However, techniques for purging and efficient transfer to the use vehicle must be developed. While the service station could look much like today's station it is not yet established whether the automobile tank should be refilled in place or exchanged for a more controlled refilling(16).

Any attempt to examine the possibility of a major modification to our present private transportation system should also look at the consequences to the overall energy situation. Consumption of gasoline in 1972 was approximately 10^{11} gallons (approximately 10^{16}Btu). To provide the hydrogen equivalent via electrolysis starting with a thermal energy source would then require approximately 3 x 10^{16}Btu. If all the hydrogen is to be liquefied and this additional energy must also come via electricity originating from a thermal source, approximately 10^{16} additional Btu are required. The result is multiplication of the source energy requirement by a factor of three (for hydrogen) or four (for LH$_2$)(18). This amount can be reduced considerably by the more efficient burning of hydrogen; fuel savings of up to 50% have been reported(13). However further modification to automobiles to decrease fuel consumption will also be necessary.

The 1968 production of hydrogen in the U.S. amounted to 2.28 x 10^{12} ncf(19). To replace the 10^{11} gallons of gasoline used in 1972 would require approximately 15 times this hydrogen production. The maximum LH$_2$ production that once existed in the U.S. was 1.8 x 10^8 gal/yr. Thus to replace 1972 gasoline usage with LH$_2$ would require a 1600 fold increase in liquefaction capability.

Switchover to a hydrogen powered transportation system would be accomplished without major disruption(16). A dual-purpose fuel engine operating on either hydrogen or gasoline could be used as hydrogen distribution is introduced. In this manner cities where pollution problems are worst could be converted first. Over a period of ten years an adequate distribution system could be built. Such a LH$_2$ system would require (for fuel consumption at the 1972 level) 137 GH$_2$ production facilities (e.g., electrolysis plants each 73 ton/h), 800 liquefaction facilities (300 tons/day each), 300,000 service stations and 20,000 bulk transport trailers. The total cost has been estimated at $133 billion(18). While this cost is great, it should be compared to a National Petroleum Council forecast of $110 billion expenditure over the next 13 years for exploration, capital equipment, etc.(20).

The cost of the LH$_2$ fuel is, of course, very speculative. It has been estimated that given a production and distribution system, present techniques could allow operation of an automobile at no more than 66% cost increase. However, without a hydrocarbon source for producing hydrogen this price would depend on the ultimate price of source energy. Based on Gregory's estimate of approximately $3.00/$10^6$Btu(21) for electrolytic hydrogen, fuel operating costs of approximately 7¢/mile (2-1/2 times present gasoline cost) has been predicted(18). However, for a thermochemical hydrogen cost of ~$1.50/$10^6$Btu (Fig. 4), the fuel operating cost could be reduced to 3.5¢/mile.

In the operation of an automobile with hydrogen (and certainly LH$_2$) safety is an important consideration. Certainly much more detailed study is required to result in the best possible systems for purging, venting, disposal, etc. However, preliminary studies indicate LH$_2$ can be safely produced, transported, stored, and vented (16). Considering the previous record of automobile accidents (50,000 deaths/yr), a LH$_2$ fuel system with almost no safety precautions would not significantly alter this most dangerous aspect of an automotive transportation system.

In conclusion it is submitted that hydrogen seems to offer the most efficient and least disruptive automotive fuel system alternate to gasoline. Liquid hydrogen <u>is</u> a possible fuel storage alternate. Such a system will be more costly in energy source requirements. Some advantages may be gained from use of the refrigeration in the LH$_2$ e.g., generation of O$_2$ enrich oxidizer from air.

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