BNL 21498

J

Conf-760482--1

HYDROGEN STORAGE, WATER ELECTROLYSIS AND FUEL CELLS FOR ELECTRIC ENERGY STORAGE*

F. J. Salzano, C. Braun, A. Beaufrere, S. Srinivasan
G. Strickland, J. J. Reilly
Department of Applied Science
Brookhaven National Laboratory
Upton, New York 11973

April 1976

ABSTRACT

The Brookhaven National Laboratory (BNL), supported by the Energy Research and Development Administration (ERDA) has in progress a program to develop the technologies of electrochemical hydrogen production, storage and conversion to electricity in fuel cells as a method of utility energy storage. The process and physical configuration, performance and costs of such a system are presented and discussed, as well as the prognosis for eventual application in a utility system. The key requirement necessary to make hydrogen production attractive for utility applications is the flexible and maximum utilization of the capital facilities required for production, storage, and where applicable, electric conversion.

INTRODUCTION

In recent years, hydrogen has received a great deal of attention as an energy supply and storage media.(1-19) This attention is in recognition of the ease with which hydrogen can be

---

*Paper presented at a meeting Vendredi 9 Avril 1976, Grenoble - Journee d'etudes organisee par - SEE - Groupe regional - Dauphine-Savoie. President: M. Buyle-Bodin, et Section 14 (Electrochimie-Electrometallurgie-Electrothermie), President: M. Laurent. Le Stockage de L'Energie Par Voie Electrochimique Quelques Voies Nouvelles.

CONTRACT NO. E(30-1)-16

DISCLAIMER

produced from non-fossil energy sources such as nuclear and solar. This interest also recognizes the important role played by storable portable fuels and the substitution possibilities for hydrogen in the energy system.

Presently, hydrogen is an important industrial commodity, which in terms of resources consumed in the United States, corresponds to approximately 1% of the total ($\sim 1 \times 10^{15}$Btu/yr). Projected industrial demand based on current trends is expected to grow, and by the years 1985 and 2000 may reach the level of 1.5×10^{15}Btu/yr and 3×10^{15}Btu/yr, respectively.(18) Irrespective of whether or not the concept of the so called "Hydrogen Energy Economy" comes to fruition, hydrogen now plays and will continue to play a major role in the energy system. Current hydrogen demands are primarily supplied from natural gas and petroleum resources. These resources are currently in short supply and their availability is expected to decline with a corresponding rise in prices. Eventually these resources will be effectively exhausted. As this trend continues, it is expected that a major fraction of future industrial demands for hydrogen will be supplied from coal; however, as more and more nuclear capacity becomes available, smaller, but significant fractions of the industrial hydrogen requirements could be supplied from these energy sources. Thus, from a utility point of view, hydrogen production is one approach among many, which can help level the output load from nuclear systems and allow maximum utilization of available capital facilities. Unlike other storage options, the hydrogen produced can be used inside, or sold outside of the electric utility system, thus offering versatility and flexibility unavailable with other storage schemes.

The problem of choosing between various storage schemes for a utility system is obviously a complex question in that not only are various technological approaches possible, but there are also non-storage and non-technological options which could achieve load leveling of a nuclear electric system to varying degrees. The various storage options to be considered take many forms, each with its own unique characteristics; however, a quality that distinguishes them is the practical and economic residence time periods for the energy stored. Some options such as superconducting magnetic energy and flywheels storage appear best suited for short time periods on the order of minutes or hours. Various battery options appear attractive for daily storage. Pumped storage is presently operated on a weekly cycle with energy added in large quantities on weekends and smaller additions made during the week.

Hydrogen as an energy storage option appears to be unique in terms of the variety of ways in which it can be applied as an energy storage medium. The various modes of application which generally represent long term storage options, i.e., either weekly cycles or longer are listed below.

1) The most widely discussed option is hydrogen electric-to-electric storage system, which unlike the battery options may be attractive for application involving weekly cycles.

2) Hydrogen could simply be produced from excess nuclear capacity and sold as an industrial commodity or injected into existing natural gas pipelines of combination electric-gas utility systems. This associated with the concept of underground seasonal storage has been discussed.

3) It is likely that as a result of storage capacity hydrogen markets will be interruptible and hydrogen production would be possible from nuclear spinning reserve where the electric supply could quickly and easily be shifted from hydrogen production to the existing electric grid to meet peak or unexpected electric demands. Coupling this concept with seasonal storage has some attractive features.

4) At a time when efficient low cost reliable fuel cells become viable electric generating devices hydrogen could be produced to supply supplemental fuel to fuel cells, or hydrogen storage would serve as capacitance to reduce or eliminate the varying load on distillate fuel reformers required by oil fed systems. The prospects for "dual mode" systems in which hydrogen would be produced and distributed to either fuel cells for electric production or injected into the natural gas system has been well discussed by R. Fernandes.(20)

5) The prospects may be attractive for hydrogen and oxygen production and storage at central station nuclear plants in which the hydrogen and oxygen combustion would supply super heat to a low pressure nuclear steam produced in an LWR and subsequently used to generate electricity to meet peak demands in a super heat turbine. Incremental efficiencies for hydrogen oxygen conversion in the range of 50% to 60% appear achievable.

6) And last, but not least, a new concept is being considered at BNL which involves the electrolysis of hydrochloric acid (HCl) in an electrolyzer which serves also as a fuel cell to recombine the H_2 and Cl_2 for electric production. Thus,

this system via storage of H_2 and Cl_2 would serve as an electric-to-electric storage system with an overall efficiency in the range of 70% to 80%. A further advantage is that by supplying pure water to the electrolyzer hydrogen and oxygen would be produced in the same unit, thus reducing the required capital investment. This system would offer great flexibility and allow utilization of available technology from the large-scale electrochemical industry, e.g., for chlorine storage and chlorine electrode systems.

In general, when considering the application of hydrogen as an energy storage system it is desirable to design systems which allow maximum flexibility of operation and thus have high utilization factors for the required capital facilities.

In this paper we discuss hydrogen as an electric-to-electric storage option in detail and present recent cost estimates for such a concept as well as discuss its competitive position and future prognosis relative to the allowed costs. We will also discuss the application of hydrogen production for natural gas injection, and the HCl electrolysis scheme for electric-to-electric storage and hydrogen production.

ELECTRIC-TO-ELECTRIC STORAGE

The Brookhaven National Laboratory with support from the ERDA and with some support from ESEERCO has been developing the technologies required for electric-to-electric storage via hydrogen production storage and reconversion. Work in progress at BNL consists of a variety of efforts ranging from engineering analysis and design of hydrogen storage plants to improvements in the techniques of electrolytic production.(21) This work includes plans to construct a prototype electrolytic hydrogen production and storage facility based on the use of iron-titanium hydride and which could be coupled to a fuel cell for conversion to electric energy.

In the scheme presented below it is assumed that electric energy supplied from a utility network during off-peak hours is used to produce hydrogen which is stored in an iron-titanium hydride compound. During peak-load periods, the hydrogen is released by heating the hydride and used to generate electric power in a fuel cell.

During hydrogen storage (metal hydride formation) energy is liberated and must be removed; during hydrogen release, energy must be supplied. Two methods for removing or supplying the energy have been considered. The first, termed "convective case," involves transferring heat to or from circulating hydrogen which flows through the hydride and heaters or coolers external to the hydride containment vessels. The second, termed "conductive case," involves transferring heat to or from a heat transfer fluid which flows through tubes buried in the hydride internal to the hydride containment vessels. The first approach is less attractive because under long cycling the hydride particles undergo size reduction and would likely exhaust from the storage vessel.

A preliminary plant design and cost estimates were made utilizing a "conductive type" metal hydride hydrogen storage bed. This design was based on chemical characteristics of iron-titanium as determined in the labroatory,(22, 23) small-scale engineering test bed data(24) and on engineering analyses made by the BNL staff and plant designs by its subcontractors.** Technology representative of the current state-of-the-art and advanced technology are separately considered in the cost and performance estimates. The design details presented consider the use of current technology.

PLANT PROCESS AND DESIGN

Figure 1 is a flow schematic for the overall plant process. During the hydrogen charging phase, high voltage, 3-phase, ac power from the utility power network is transformed and rectified by solid state rectifiers to dc. The dc power is supplied to water electrolyzers which are capable of producing 3250 lbm-H_2/hr and 25,800 lbm-O_2/hr, maximum. During normal operation, 2800 lbm-H_2/hr and 22,000 lbm-O_2/hr are produced. The oxygen is released to the atmosphere, while the hydrogen is cooled and passed through a deoxygenator to remove residual oxygen. The hydrogen is then passed through a dryer to remove residual water vapor and the final product hydrogen gas has a dew point of -76°F or less. The dry gas then flows to the combined hydride bed/heat exchangers where it is absorbed and stored.

**Burns & Roe, Inc., Engineers and Contractors, Hempstead, N.Y.

Figure 2 shows pressure-temperature conditions and other characteristics during the hydrogen charging of the combined powdered metal hydride bed/heat exchangers. During charging, the valve downstream of the hydride beds is closed. Cooling water circulates through the heat transfer tubes buried in the metal hydride to remove the heat released as the hydrogen is absorbed and iron-titanium-hydride is formed. The sensible heat in the bed is also removed by this stream. The cooling duty is thus determined by the requirements that 2800 lbm per hour of hydrogen be stored and 6750 Btu be removed for each pound of hydrogen added.

Figure 3 shows pressure-temperature conditions and other characteristics during the discharging (desorption) of the combined hydride bed/heat exchangers. During discharging, the valve between the hydrogen dryer and the hydride beds is closed, and the valve from the beds to the fuel cell packages opened. Water, heated using waste heat from the fuel cell packages circulates through the same heat transfer tubes used during storage, to supply the heat of dehydriding and sensible heat as the hydrogen is released. As the sensible heat energy is small compared to the reaction energy required, it is neglected. The heating duty is thus determined by the requirements that 2800 lbm of hydrogen be released per hour and 6750 Btu be supplied for each pound of hydrogen released.

The general arrangement plan view of a 26MW(e) iron-titanium metal hydride storage (conductive type) electric power plant is shown in Figure 4. The main subsystems of this plant includes a 24 module, Lurgi high pressure (30 atm) water-KOH electrolyzer, 10 iron-titanium hydride hydrogen storage heat-transfer beds, and a 24 module hydrogen-air fuel cell system using phosphoric acid as the electrolyte.

The electric auxiliaries include; an ac-dc rectifier to convert 3-phase, 60 H_Z power from the utility network to operate the electrolyzers, an inverter and transformers to convert the fuel cell 500 volt dc electrical output to 3φ 6.9kV ac bus voltage. Figure 5 shows the hydrogen flow between the major components and the auxiliaries associated with producing and storing the hydrogen including electrolyte separators, hydrogen coolers, water separators, deoxygenators and dryers. Figure 6 is a flow diagram of the process heating and cooling systems. The cooling/heating water auxiliaries include: hydride cooling water-tower system, electrolyzer intercooling system, electrolyzer coolant cooler, and a dehydriding heating water system operated on reclaimed heat from fuel cells. An electrolyte flow diagram is shown in Figure 7. It is to be noted that a plant utilizing an advanced technology electrolyzer and fuel cells of the General Electric solid polymer type require no flowing electrolyte.

Figure 8 is a simplified one-line diagram of the plant's main electrical system. This system is comprised of a 115kV high-voltage substation, four 34 MVA, 115/6.9kV stepdown transformers, 6.9kV switchgear, 24 rectifiers rated at 6.9kV, 3.4MW, and 24 inverters rated at 6.9kV, 1.1MW.

PLANT PERFORMANCE

Figure 9 shows the estimated nominal plant performance. During the hydriding portion of the plant cycle, the gross electrical power input is 72.5MW(e) 3 ø ac to the solid state rectifiers. The rectifiers have an estimated conversion efficiency of about 97 percent, so 2.16MW are rejected to the atmosphere as heat and about 70.0MW(e) dc are distributed to the 24 electrolyzers. The electrolyzers convert the 70.0MW(e) into 2800 lbm-H_2/hr with a conversion efficiency of about 72 percent, based on the high heating value of hydrogen (61,000 Btu/lbm). About 20.0MW of heat are rejected directly and through the circulating cooling water system to the atmosphere (see Figure 6). The 2800 lbm-H_2/hr produced by the electrolyzers are stored in the hydride beds at a uniform rate with an assumed efficiency of 100 percent; i.e., with no leakage. The heat of hydriding, 5.54MW, (6750 Btu/lbm), is rejected to the atmosphere by means of the cooling water system, (see Figure 5 and 6). Hydrogen chemical energy is thus stored at the rate of 50.1MW, based on the high heating value of hydrogen, and the nominal hydriding effectiveness for the charging portion of the plant cycle, defined as the ratio of the rate of hydrogen chemical energy stored to the total plant power required, is 69 percent.

During discharging or dehydriding, hydrogen is liberated from the hydride beds at a uniform rate of 2800 lbm-H_2/hr. The heat of hydriding, 5.54MW, is supplied, for normal operation, by utilizing heat rejected by the fuel cell packages, which are assumed to operate with a conversion efficiency of 55 percent, based on the high heating value of hydrogen. In addition, about 0.44MW of heat from the fuel cell packages are also used to preheat the hydrogen before it enters the fuel cells to prevent quenching the electrochemical reactions. From the 50.1MW rate of hydrogen chemical energy input to the fuel cells (2800 lbm-H_2/hr), 27.6MW(e) dc is extracted and 22.6MW is rejected. As noted, 5.54MW and 0.44MW of the rejected power are utilized, while the remainder is transferred directly to the atmosphere. The 27.6MW(e) dc is distributed to the SCR inverters, which have an estimated conversion efficiency of 97 percent, and converted to 26.7MW(e) with about 0.90MW of heat rejected to the atmosphere. About 0.7MW(e) of the 26.7MW(e) is used to power auxiliaries during dehydriding leaving a net plant output of 26.0MW(e) 3 ϕ ac. Thus, the nominal dehydriding effectiveness for the power generation portion of the plant cycle, defined as the ratio of the net plant output to the rate of hydrogen chemical energy available, is 52 percent. For the complete plant operating cycle, therefore, the efficiency or ratio of net plant output to total plant input, is 36 percent. Even with a projected fuel cell conversion efficiency of only 55% and the overall plant efficiency could be improved to a value above 50% with a 90% efficient electrolyzer. The key to greater efficiencies is in the utilization of a conversion device more efficient than the first generation phosphoric acid air fuel cell expected to be available. Alkaline fuel cells involving the use of oxygen do achieve efficiencies as high as 70%(19) which coupled with a 90% electrolytic production efficiency would set 60% as an upper bound for the overall electric-to-electric storage efficiency.

CAPITAL COSTS

The capital cost of the first <u>one-of-a-kind</u> 26MW(e) metal hydride storage electric plant described herein and constructed on an improved building site in the Northeastern part of the United States is estimated at $170/kW(e)-hr for a ten hour charge/discharge cycle. This is considered to be representative of the state-of-the-art and does utilize available components, except for the fuel cell. Thus, this cost estimate serves as a first baseline of comparison with other types of electric storage plants based on available technology and allows judgment regarding the value of advanced technology development and procedures. An advanced technology 1980 demonstration plant with the same storage and process scheme but having higher overall efficiency (50%) is estimated at $66/kW(e)-hr. This higher efficiency is mainly accomplished by operating the electrolyzers at higher temperatures.(21) Table I shows the distribution of costs of this advanced technology plant now under study at BNL and Table II indicates the cost distribution as a percentage compared with the present state-of-the-art power plant described above. By far the greatest cost reduction comes about by the utilization of an advanced technology electrolyzer. Although a very reliable unit of moderate efficiency, the present Lurgi electrolyzer is representative of current technology and market conditions, while the advanced technology electrolyzer now under study at BNL and its subcontractors,(19,21) is capable of operating at much higher current densities as well as consisting of a fewer number of modules. Thus, it will be smaller and lighter which leads to lower costs and will require less floor space and foundation. It also will have lower installation costs as there will be less piping, valves, controls and instruments. The accessory electrical equipment will also be less expensive because there will be fewer number of major modules.

The allowed cost for the introduction of electric storage devices into the national energy system was examined, utilizing the Brookhaven Energy System Optimization Model (BESOM). Allowed cost curves versus distillate oil prices shown in Figures 11 and 12 were reproduced from Reference (25), but put in terms of 1975 instead of 1970 dollars. At the present oil price of approximately $\$2.6/10^6$Btu and at a load factor of 0.1, Figure 11 indicates that the allowed cost, or break-even cost for the advanced technology electric peaking plant with an overall efficiency of 50%, would be about \$500/kW(e). However, if the cost of fuel were to increase to $\$3.9/10^6$Btu, as indicated in Figure 12, the allowed cost would approach the above \$660/kW(e) advanced technology plant cost.

It should be noted from the reference cost curves that allowed capital costs are a strong function of load factor as well as the overall efficiency of the plant. However, the latter effect greatly diminishes when the efficiency is greater than 30 to 50%, where the upper part of this efficiency range is for the higher load factor. Thus, high utilization of a high efficiency plant would be most profitable. For example, at a load factor of 0.25 and at an efficiency of 50%, the estimated allowed capital cost in 1975 dollars would be about \$650/kW(e) at approximate level of present fuel costs.

An approach which would achieve higher plant utilization of a hydrogen production and storage system is to operate in the so called "dual mode."(20) In this case, hydrogen would also be generated from off-peak power, stored, and injected into the natural gas fuel supply system as well as being used to generate electricity during peak-load periods. This hydrogen would be produced by the same equipment as that used for the electrical branch of the system where fuel cells would convert the distillate fuel or hydrogen to electricity on demand. The use of hydrogen in a dual mode plant could greatly increase the utilization of the fuel cells and electrolyzer equipment. Also, the fuel cells would be operated as dual fuel devices, using distillate fuel a major fraction of the time and hydrogen for peaking applications only. In this way the utilization factor for the fuel cells could be as high as 50%. Any system approach which will maximize the utilization of the production and conversion equipment is highly desirable.

HYDROGEN INJECTION INTO THE NATURAL GAS PIPELINES AND "DUAL MODE" CONCEPT

Hydrogen injection into the natural gas pipelines can be considered on its own merits as an end to itself, or it can be carried over to its logical extension within joint electric and gas utilities, which is the "dual mode" concept. Dual mode systems have been referred to in the literature as the "two-way electric-gas transformer" or "dual-input dual-output generating device."(26) A discussion of hydrogen supplementation of natural supplies is now given, followed by consideration of dual mode concepts.

HYDROGEN INJECTION INTO NATURAL GAS PIPELINES

There are two basic incentives for hydrogen injection into the natural gas pipelines: Supplementation of dwindling natural gas supplies and improved utilization of base and intermediate load electric power plants. It is thus evident that hydrogen injection is most attractive to joint electric and gas utilities. Large-scale implementation of this concept, based on possible demand diversity between the electric and gas subsystems can lead to a greater integration of the two components of the joint utility, and in fact to a new definition of the role of such utilities as energy companies. On the technical side, hydrogen injection can lead to implementation of seasonal storage systems, compared with the daily and weekly storage concepts considered so far.

Hydrogen injection schemes involve the utilization of available low cost off-peak electric power (preferably nuclear) to electrolyze water. The product hydrogen is then injected up to a predetermined volumetric flow rate, into the natural gas pipelines. Three production locations can be considered:

1. Electrolyzer banks can be installed within a nuclear central station plant. The electrolytic hydrogen produced with off-peak power is then transmitted into the nearest pumping substation of the natural gas pipeline network.

2. Electrolyzer banks are installed within a natural gas substation. Off-peak electric power from the electric network is transmitted into the natural gas substation, and the product hydrogen is injected directly into the pipeline.

3. Electrolyzer banks are installed as a lightly loaded electric substation, preferably one close to a natural gas valving station. The available off-peak power at the substation in periods of slack demand is utilized for electrolytic hydrogen production. The hydrogen is then transported a relatively short distance to the nearest natural gas pipeline valving station.

The different production schemes have specific importance, when considered in the context of dual mode generating devices, as discussed later.

As can be seen from the above discussion, implementation of hydrogen injection schemes will depend on several factors such as: expected natural gas shortfall, expected availability of off-peak power, electrolyzer availability, hydrogen embrittlement problems and the expected economics of electrolytic hydrogen production. These factors are now discussed, as related to possible near term implementation of injection schemes. Long term considerations are mentioned later.

NATURAL GAS SUPPLY AND CURTAILMENTS

A recent Federal Power Survey report(27) indicates that on a national level the deficiency in natural gas supply is expected to be on the order of 22.1 percent of the projected firm requirements for the twelve month period September 1975 - August 1976. When considering the Northeast U.S. region, which includes approximately the service territories of the New England and New York Power Pools, and the Pennsylvania-Jersey-Maryland Interconnection, the projected natural gas curtailment for the same 12 month period is about 528 Tcf which corresponds to 22.6 percent of the year 1972 supply. These projections are based on Reference (27) data and the Energy Future of the Northeast study now being conducted at Brookhaven National Laboratory (28). No reduction in this level of deficiency can be projected for the Northeast region in the time frame of 1975-1985. Thus, clearly there exists a need to supplement the dwindling natural gas supplies with any additional gas sources.

AVAILABILITY OF OFF-PEAK NUCLEAR POWER

Public attention has recently focused on delays in construction of new nuclear plants. However, several regions of the country which embarked on a nuclear program to lessen their dependence on imported oil as power plants fuel, now find themselves with large nuclear fractions of the total installed capacity and with reduced electric demand due to the recent economic slowdown. Such regions which include the Chicago area (Commonwealth Edison Service area) and New England region may have excess nuclear capacity to serve a lower than expected load growth till 1985. Thus, Commonwealth Edison has recently reported that 51 percent of its electricity generation was from nuclear power plants during November 1975.(29) The installed nuclear capacity now comprises 19.6 percent of the New England Power Exchange capacity, and this fraction is expected to increase to 26.7 percent and 37.7 percent by 1980 and 1985, respectively, according to Brookhaven projections.(28) It is possible to estimate the available off-peak energy as percentage of the total electric system energy production as a function of the system nuclear capacity based on a correlation developed by Public Service Electric and Gas Company.(30) Using data from Reference (30) off-peak power available in New England will be 0.4 and 2.0 percent of total generation in the years 1980 and 1985, respectively. Long term nuclear capacity projections beyond 1985 are quite unreliable in the current situation; however, the Brookhaven study of the Energy Future of the Northeast(28) indicates nuclear fractions of the total installed capacity in the Northeastern United States as 0.39 and 0.48 in the years 1990 and 1995. These nuclear capacity fractions correspond, according to Reference (30), to nuclear off-peak power in the range of 3.5 and 7.0 percent of the total generation in 1990 and 1995. Thus, due to over construction, several regions of the country may have a sufficient amount of off-peak nuclear power in the near term (until 1985), to start modest programs involving electrolytic hydrogen production. Larger amounts of nuclear off-peak power may become available beyond 1985, however, projections beyond 1985 are not accurate.

AVAILABILITY OF ELECTROLYSIS EQUIPMENT

Water electrolysis equipment that can be installed on a substation level has been described above in this paper, and in other recent reports such as Reference (31). Current projections indicate that first generation advanced electrolyzers, costing \$100/kW hydrogen output and having conversion efficiencies in the range of 88% will become commercially available during the period 1981-1985. Such electrolyzers using power costing in the range of 10 mills/kWh for off-peak energy (supplied by a mix of fossil and nuclear plants) will produce electrolytic hydrogen in the cost range of \$5-6/10^6Btu.

ECONOMICS OF ELECTROLYTIC HYDROGEN PRODUCTION

As indicated above, the electrolytic hydrogen cost is a function of the electrolyzer capital cost and conversion efficiency and the off-peak electric power cost. Assuming that advanced electrolyzers become available around 1985, with capital cost of \$100/kW electricity input and efficiency range of 0.85-0.90, the expected hydrogen cost will be in the range of 3.5-5.5 \$/10^6Btu which corresponds to off-peak power cost of 5 to 10 mills/kWh. This should be compared with recent Federal Power Commission report which indicated that the cost of interruptible natural gas to New England power plants was \$1.2/10^6Btu and the cost of firm gas supplies to Middle Atlantic utilities was \$1.56/10^6Btu in July 1975. However, as the price of natural gas is further deregulated the future cost of this fuel is expected to be considerably higher than these figures. Current projected prices of coal derived synthetic natural gas are in the range of \$3 to \$4/10^6Btu.

The economics of hydrogen supplementation of natural gas supplies will depend on two factors: (1) the ratio of the cost of hydrogen to the cost of the conventional fuel it is about to replace in the different areas of hydrogen utilization, and (2) the ratio of the cost of hydrogen to other natural gas supplementary fuels. Thus, it is obvious from the above cost data that hydrogen will be much more expensive than current natural gas prices, though this may later change as natural gas prices are deregulated or it becomes more scarce.

The cost of hydrogen versus synthetic natural gas or imported liquified natural gas--all of which are possible supplants of the domestic natural gas supply, have to be considered. It can be argued that during the period 1981 - 1985 natural gas shortfalls will increase, the synthetic fuels program will not yet be commercialized, certainly not to supply fuels to Northeastern United States and imported natural gas on top of political and regulatory problems, may be required to supply a minimum amount of gas to firm customers. Hydrogen supplementation of natural gas supplies may become economically attractive.

An initial small scale (regional basis) implementation program for electrolytic hydrogen injection into existing natural gas lines may be tailored to specific localized circumstances. Factors such as local availability of low cost off-peak nuclear power, the existence of economically acceptable advanced electrolyzers could be combined to allow hydrogen injection into natural gas at less than 10 percent volumetric concentrations. This could be done with virtually no changes in gas transmission facilities and no change in end use devices. Such utility or regional based program could be carried out before 1985 at a moderate level and expanded.(32)

"DUAL MODE" ELECTRIC-HYDROGEN GENERATING DEVICES

The key technological development required to make the "dual mode" scheme viable is the availability of commercial fuel cells. Fuel cells development status has been reviewed extensively in References (19, 33).

The simplest concept of a "dual mode" device is a fuel cell that can burn either fossil fuel by first reforming it to hydrogen in an attached reformer, or externally produced and purified hydrogen. The hydrogen source can be either a water electrolysis plant run by an electric utility as described above, or a remote coal gasification plant that produces commercial hydrogen as a prime or by-product. Such a device can be optimized to operate at intermediate or even base load while burning distillate oil or natural gas and electrolytic hydrogen during peak demand periods. The "dual mode" designation refers here both to operation at several load factors and to burning two different types of fuels.

The advantage of burning two types of fuels in the fuel cell is that the relatively low cost fossil fuels can be utilized to supply intermediate or even base load demand and to a lesser degree to keep the reformer operated at steady state conditions for long periods of time. In order to supply cyclic peak load demand and avoid the necessity of starting and shutting down the reformer several times a day, the stored electrolytic hydrogen can be utilized. This type of "dual mode" device can be constructed at central station plants or on a dispersed generation basis, at heavily loaded substation on the transmission network. External source of fossil fuel can be used or natural gas can be withdrawn from the natural gas pipelines. Similarly, any source of hydrogen fuel for peak load power supply can be provided; i.e., electrolytic hydrogen stored in metal hydrides or in the gas transmission pipelines, or coal derived hydrogen stored in high pressure steel bottles.

A more complex "dual mode" scheme involves the combination of a simple output electrolyzer with hydrogen/fossil fuels dual input fuel cell. In this concept, the electrolyzer bank of a standard size 26MW(e) station, as described in Reference (34), produce hydrogen which is stored on-site, and burned by the co-located fuel cells. Distillate oil or natural gas can be burned to supply intermediate electric power, and hydrogen is burned during peak demand periods. This generating concept achieves a greater degree of integration between the electric and the gas sections of large power utilities.

The most complex form of a "dual mode" generating concept incorporates a dual output electrolyzer with a dual input fuel cell. This makes the operation of the electrolyzer fuel cell combination a completely reversible process that can be run in any direction depending on the diversity of the electric and gas demands. Such concept may also require a large capacity hydrogen storage system and is in fact the vehicle through which seasonal storage may be introduced into the operation of joint electric and gas utilities. Two variants of this concept have so far been proposed. One proposal assumes co-location of the main system components--the electrolyzer fuel cell, hydrogen storage and possibly methanator. This concept has been proposed by Public Service Electric and Gas personnel(26) and labelled "Two-Way Electric-Gas Energy Transformer." The other concept proposed by R. Fernandes(20) assumes dispersed location of the electrolyzer and fuel cells along the electric transmission network. The electrolyzers are located at highly loaded substations which are located near to valving substations of the natural gas transmission network. The fuel cells are located at heavily loaded electric transmission substation and augment the electric supply at these points. The advantage of the dispersed generation concept is the ability to utilize the natural gas pipeline network itself as the (possibly seasonal) hydrogen storage system.

In both of these complex schemes the electrolytic hydrogen is either sent to the fuel cells for reconversion to electricity or injected into the natural gas pipelines. At the other extreme point of the "dual mode" concept the fuel cell can burn either electrolytic hydrogen or natural gas-hydrogen mix withdrawn from the natural gas pipelines and sent through reformer banks for complete conversion to hydrogen prior to burning. Given a set of performance characteristics for the fuel cell and the electrolyzer components, the operating parameters that lend themselves to optimization are the fractions of the electrolyzer output that are burned or injected into the natural gas pipelines, and the composition of the input fuels mix into the fuel cell.

HYDROCHLORIC ACID ELECTROLYSIS

Conventional water electrolysis-fuel cell storage systems have the disadvantages of a relatively low electric-to-electric efficiency (~50%) and a high cost, mainly because three major components (water electrolysis cell, metal hydride reservoir and fuel cell) are necessary. The main reason for the inherently lower efficiency of the hydrogen-air system, compared with the other electrochemical systems is the irreversibility of the oxygen electrode reaction. Further, since different electrocatalysts have to be used for oxygen evolution and reduction, two electrochemical systems are necessary instead of one as in the case of a battery.

The proposed electrochemically regenerative closed cycle hydrogen-chlorine fuel cell system(35) involves (1) using off-peak power to electrolyze hydrochloric acid; (2) metal hydride storage for hydrogen and storing of chlorine as a liquid or as the hydrate; and (3) combining the hydrogen and chlorine in fuel cell for peaking operations and storing the hydrochloric acid. The main advantages of such a system are: (1) the electrode reactions of hydrogen and chlorine are quite reversible. Thus, one can expect to achieve an overall efficiency (electric-to-electric) higher than 70%; (2) the same electrodes can be used as electrocatalysts in both modes (chemical and electricity generation). Therefore, the same electrochemical cell can be used for both functions which cuts down the capital costs; (3) it should be possible to use the same cell in a third function for electrolysis of water to produce hydrogen and oxygen at a high efficiency using off-peak power. The hydrogen produced could be used for injection into natural gas pipelines or in chemical industry applications. The hydrogen selling price could be used as a credit against the cost of the hydrogen-chlorine system; (4) the chlorine production and storage technology is well known and developed; (5) the system will operate at low temperatures (<100°C); (6) though HCl and Cl_2 are corrosive chemicals the corrosion problems at less than 100°C should be at least an order of magnitude less than with electrochemical systems involving alkali metals and their salts at temperatures greater than 400°C; (7) the reactants for chemical and electricity generation are stored outside the cell. Thus, the sizes of the electrochemical conversion devices are relatively small compared to batteries, and will scale well for long duty (weekly) cycles; (8) Scaling the hydrogen-chlorine system for intermediate load operation requires only larger reactants storage capacity and cycling rate through the system. This in contrast to other electrochemical storage systems where scaling up requires the installation of a larger capacity (and capital cost) system.

Compared with water electrolysis energy storage systems the hydrogen-chlorine device is expected to have higher allowed break-even costs for a given utilization factor due to the higher projected conversion efficiency and holds promise of reduced overall cost as a result of less equipment requirements and more flexible modes of operation.

CONCLUSIONS

1) The concept of a hydrogen electric-to-electric storage system is only technically viable pending the development of a commercial fuel cell.

2) Until the performance characteristics and costs of commercial electrolyzers and fuel cells are better known, the economics of hydrogen electric energy storage appears marginal at current fuel prices.

3) Assuming commercially available components the real economic incentive for implementation could materialize as fossil fuel prices in the electric sector escalate.

4) Systems applications which envision increased utilization of the electrolyzer via the dual mode or natural gas injection concepts have better economics prospects in the near term than pure electric-to-electric storage at inherently low utilization factors. This is provided the necessary technical developments progress at a reasonable rate, i.e., prototype commercial devices available by mid 1980's.

5) It is likely that hydrogen production for commercial and industrial uses will materialize in the near term as fossil prices escalate and more nuclear capacity is available.

6) We envision the initial introduction utility generated hydrogen into the non-electric sectors first and electric generation via hydrogen at a later date.

REFERENCES

(1) Hydrogen and Other Synthetic Fuels, a summary of the work of the Synthetic Fuels Panel, September 1972, prepared for the Federal Council on Science and Technology R&D Goals Study under the cognizance of the U.S. Atomic Energy Commission Division of Reactor Development and Technology TID-26136.

(2) A Hydrogenergy Carrier, Volume I Summary, September 1973, NGT 44-005-114, NASA-ASEE, Editors: Robert L. Savage, Lee Blank, Tom Cady, Kenneth Cox, Richard Murray, Richard Dee Williams.

(3) Edward M. Dickson, John W. Ryan, Marilyn H. Smulyan. SRI Project 2836, The Hydrogen Energy Economy Concept--A Preliminary Technology Assessment. Discussion Draft, January 1975.

(4) Proceedings of the Cornell International Symposium & Workshop on the Hydrogen Economy, August 20-22, 1973, sponsored by the National Science Foundation Research Applied to National Needs (RANN) Program in cooperation with the Cornell Energy Project. Simpson Linke, Editor. Published by Cornell University, Ithaca, New York, April 1975.

(5) Elihu Fein. A Hydrogen Based Energy Economy. Prepared for Northeast Utilities Service Company, Report No. 69-08-10, The Futures Group, 124 Hebron Avenue, Glastonbury, Conn., October 1972.

(6) Hydrogen Energy, A Bibliography with Abstracts, Cumulative Volume, January 1, 1974, Technical Editor, Kenneth E. Cox, compiled by the Technology Application Center, a product of The Energy Information Center, a cooperative effort of The College of Engineering and The Technology Application Center, The University of New Mexico, Albuquerque, New Mexico. (TAC-H 74-500).

(7) J. B. Pangborn, J. C. Gillis; Project Officer, E. Beyma. Feasibility Study of Alternative Fuels for Automotive Transportation, Interim Report on Contract No. 68-01-211, Paper presented at the Seventh Alternative Automotive Power Systems Coordination Meeting, U.S. Environmental Protection Agency, Ann Arbor, Michigan, May 16, 1974.

(8) W. R. Parrish, R. O. Voth, J. G. Hust, T. M. Flynn, C. F. Sindt, N. A. Olien. Selected Topics on Hydrogen Fuel. Editor, J. Hord, Cryogenics Division, Institute for Basic Standards National Bureau of Standards, Boulder, Colorado, January 1975. (NBSIR 75-803).

(9) Working Symposium on Liquid-Hydrogen-Fueled Aircraft, held at National Aeronautics and Space Administration, Langley Research Center, Hampton, Virginia, May 15-16, 1973.

(10) D. P. Gregory. A Hydrogen-Energy System. Contributors: P. J. Anderson, R. J. Dufour, R. H. Elkins, W. J. D. Escher (Consultant), R. B. Foster, G. M. Long, J. Wurm, G. G. Yie, prepared for American Gas Association by Institute of Gas Technology, August 1972.

(11) R. D. Lessard. Liquid Hydrogen as a Fuel for Future Commercial Aircraft. United Aircraft Research Laboratories, East Hartford, Connecticut, 9th Intersociety Energy Conversion Engineering Conference, San Francisco, California, August 26-30, 1974.

(12) N. C. Hallett. NASA Contractor Summary Report, Study, Cost and System Analysis of Liquid Hydrogen Production. Prepared under Contract No. NAS 2-3894 by Air Products and Chemicals, Inc., Allentown, Pennsylvania for Mission Analysis Division, Ames Research Center, National Aeronautics and Space Administration. June 1968.

(13) John E. Johnson. The Economics of Liquid Hydrogen Supply for Air Transportation. Product Manager, Hydrogen, Union Carbide Corporation, Linde Division, New York, New York., presented at the Cryogenic Engineering Conference, Atlanta, Georgia, August 10, 1973.

(14) William J. D. Escher. Prospects for Liquid Hydrogen Fueled Commercial Aircraft. Escher Technology Associates, Report PR-37, September 1973.

(15) Charles F. Meyer, Project Manager, Walter Hausz, Lohnas H. Knapp, G. Garth Leeth, David W. Lueck, John E. Steen. Phase I Study of Eco-Energy. 71TMP-44B, July 30, 1971. This study was funded jointly by Southern California Edison Co. and General Electric Co., Tempo General Electric Co., Center for Advanced Studies, Santa Barbara, California.

(16) R. F. McAlevy III, et al. Hydrogen as a Fuel, Semi-Annual Technical Report, No. ME-RT-74011, AD-787484/5GA, Contract No. Advance Research Projects Agency, Dept. of Defense #N000-14-67-A-0202-0046.

(17) James H. Kelley, Study Manager. Hydrogen Tomorrow, Demands and Technology Requirements, A National Aeronautics and Space Administration, Report of the NASA Hydrogen Energy Systems Technology Study, December 1975. Jet Propulsion Laboratory, California Institute of Technology, JPL-5040-1 Contract #NAS-7-100.

(18) ERDA Hydrogen Assessment. A Report preapred by the Brookhaven National Laboratory for the Energy Research and Development Administration, Office of Planning and Analysis, December 8, 1975, In Press.

(19) S. Srinivasan, R. H. Wiswall. Hydrogen Production, Storage and Conversion for Electric Utility and Transportation Applications. Proceedings of Symposium on Energy Storage Fall meeting of Electrochemical Society, Dallas, Texas, October 1975. In Press.

(20) R. A. Fernandes. Analysis of Hydrogen Cycle Peak-Shaving for New York State. Empire State Electric Energy Research Corporation, April 1975.

(21) G. Kissel, P. W. T. Lu, M. H. Miles, S. Srinivasan. Hydrogen Production by Water Electrolysis - Methods for Approaching Ideal Efficiencies. 10th IECEC Proceedings, 1194, 1975.

(22) J. J. Reilly, R. H. Wiswall, Jr. Formation and Properties of Iron-Titanium Hydride. Inorganic Chemistry, 13, 218, 1974.

(23) J. J. Reilly, J. R. Johnson. Titanium Alloy Hydrides Their Properties & Applications. Paper to be presented at the 1st World Hydrogen Energy Conference, March 1-3, 1976, Miami, Florida.

(24) G. Strickland, J. Milau, W. S. Yu. Behavior of Iron-Titanium Test Bed; Long Term Effects, Heat Transfer and Modeling. Paper to be presented at the 1st World Hydrogen Energy Conference, March 1-3, 1976, Miami, Florida.

(25) C. Braun, E. A. Cherniavsky, F. J. Salzano. The Economic Incentive for Introducing Electric Storage Devices into the National Energy System, BNL 20231.

(26) J. A. Casazza, R. A. Huse, V. T. Sulzberger, F. J. Salzano. Possibilities for Integration of Electric, Gas and Hydrogen Energy Systems. Paper 31-07 presented at the International Conference on Large High Voltage Electric Systems (CIGRE), Paris, France, August 1974.

(27) Federal Power Commission. Requirements and Curtailments of Interstate Pipeline Companies Based on Form 16 Reports Required to be filed on September 30, 1975.

(28) Energy Policy and Analysis Group. Discussion papers on Natural Gas, Electrical Energy Sector and Future of Nuclear Power in the Northeast, written by various members of this group. Brookhaven National Laboratory, September, December 1975.

(29) Nucleonics Week. Nuclear Power Produced 51.2 Percent of Commonwealth Edison Electricity, Vol. 16, No. 51, p 3, December 18, 1975.

(30) J. M. Burger. An Energy Utility Company's View of Hydrogen Energy Fundamentals - A Symposium Course, pp S-4-39, S-4-63, Miami Beach, Florida, March 3-5, 1975.

(31) F. J. Salzano, S. Srinivasan. Draft Summaries of Inter-National Energy Agency Meeting on Water Electrolysis at Brookhaven National Laboratory, September 1975.

(32) M. Lotker. Hydrogen for Electric Utilities - Long Range Possibilities, pp 423-428 of 9th Intersociety Energy Conversion Engineering Conference, San Francisco, California, August 1974.

(33) A. P. Fickett. An Electric Utility Fuel Cell: Dream or Reality? Paper presented at the American Power Conference, Chicago, Illinois, April 1975.

(34) A. H. Beaufrere, F. J. Salzano, R. J. Isler, W. S. Yu. Hydrogen Storage via Iron-Titanium for a 26MW(e) Peaking Electric Plant, BNL 20902, January 1976.

(35) E. Gileadi, S. Srinivasan, F. J. Salzano, C. Braun, L. J. Nuttall, A. B. LaConti. An Electrochemically Regenerative Hydrogen-Chlorine Fuel Cell as an Energy Storage System for Electric Utilities. Paper to be presented at the 11th IECEC Meeting, State Line, Nevada, September 1976.

TABLE I

SUMMARY OF INSTALLED CAPITAL COST ESTIMATES (in 1975 Dollars) OF AN ADVANCED TECHNOLOGY (1980) 26MW(e) METAL HYDRIDE STORAGE POWER PLANT, 10 HOUR CHARGE/DISCHARGE CYCLE

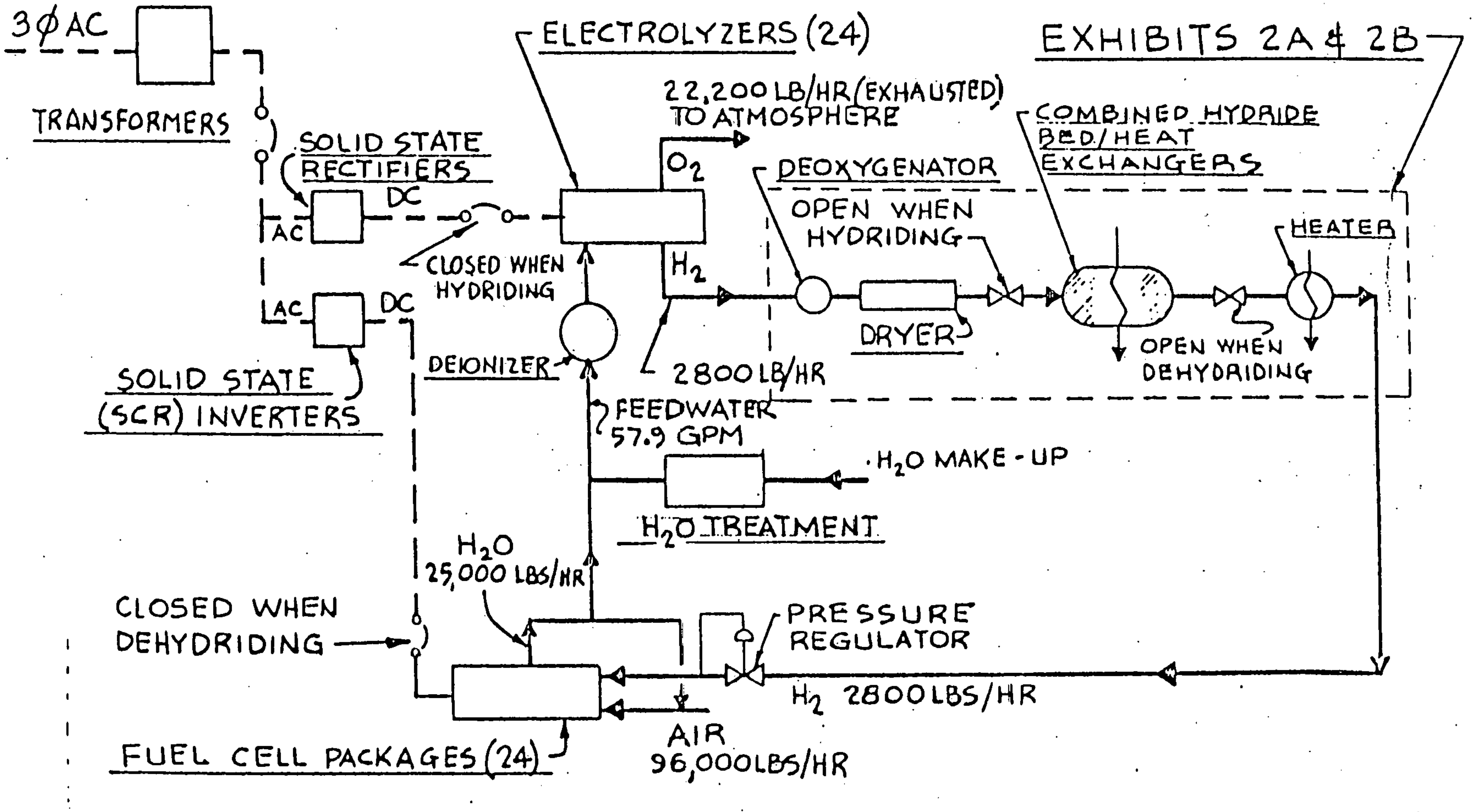
	$/kW(e)hr*	$/kW(e)*
1. Water Electrolyzer, including auxiliaries	14	140
2. Hydride Storage Bed/Heat Exchanger	6	60
3. Iron-Titanium Hydride Powder	11	110
4. Fuel Cell Packages, Including Combined Converter-Inverter	15	150
5. Piping, Valves, Controls and Instruments	10	100
6. Accessory Electrical Equipment	7	70
7. Structures and Foundations	3	30
Total Plant Cost	66	660

*Based on plant electrical output

TABLE II

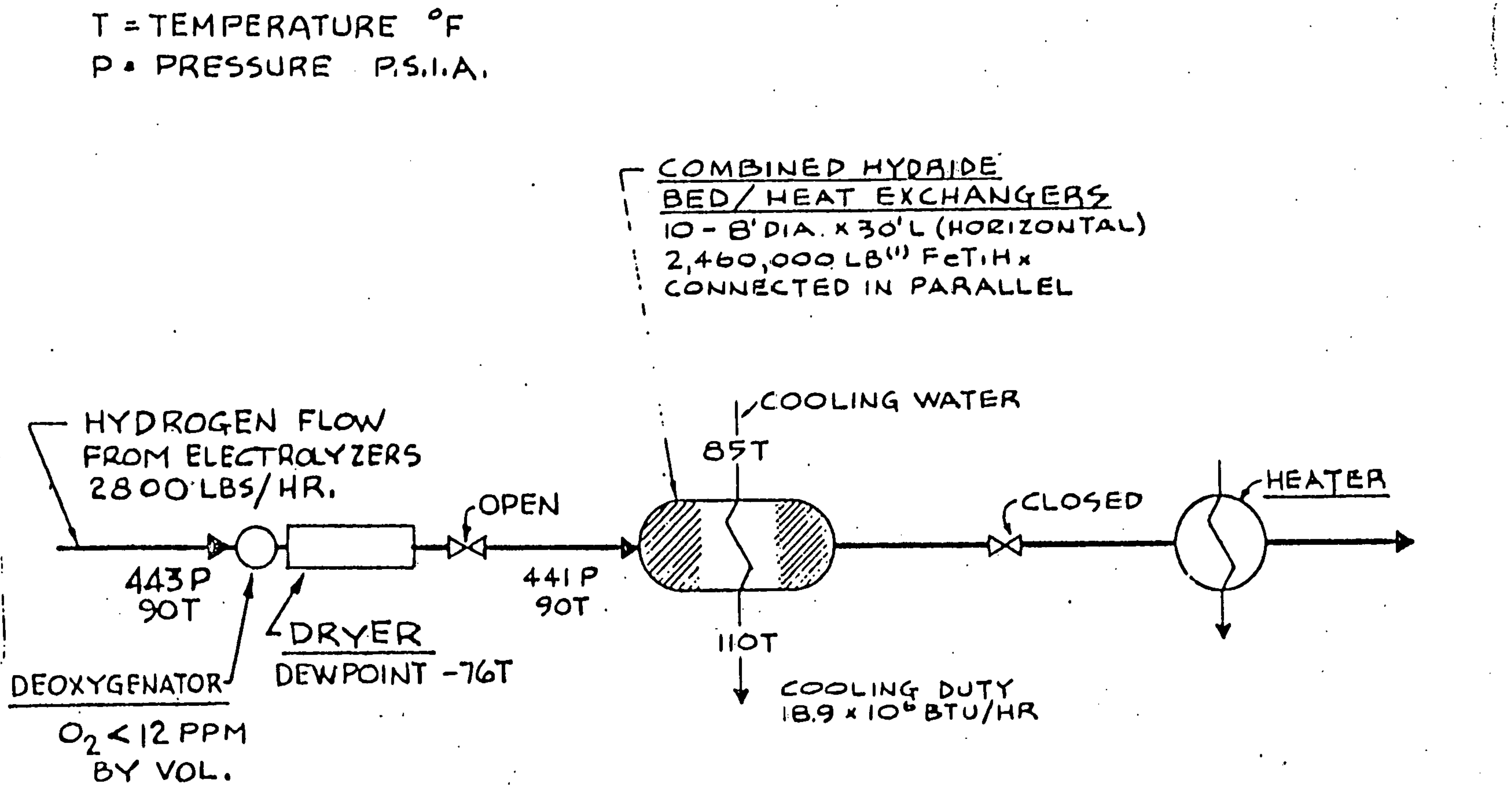
COST DISTRIBUTION
STATE-OF-THE-ART VS. ADVANCED TECHNOLOGY (1980) OF 26MW(e) METAL HYDRIDE STORAGE ELECTRIC POWER PLANT
10 HOUR CHARGE/DISCHARGE CYCLE

		Present	Advanced
1.	Water Electrolyzer, including auxiliaries	36%	21%
2.	Hydride Storage Bed/Heat Exchanger, including auxiliary H_2 purification equipment	10%	8%
3.	Iron-Titanium Hydride Powder	11%	17%
4.	Fuel Cell Packages, including Combined Converter-Inverter	12%	23%
5.	Piping, Valves, Controls and Instruments	12%	15%
6.	Accessory Electrical Equipment	11%	11%
7.	Structures and Foundations	8%	5%



METAL HYDRIDE STORAGE POWER PLANT PROCESS SCHEMATIC

FIGURE 1



NOTES

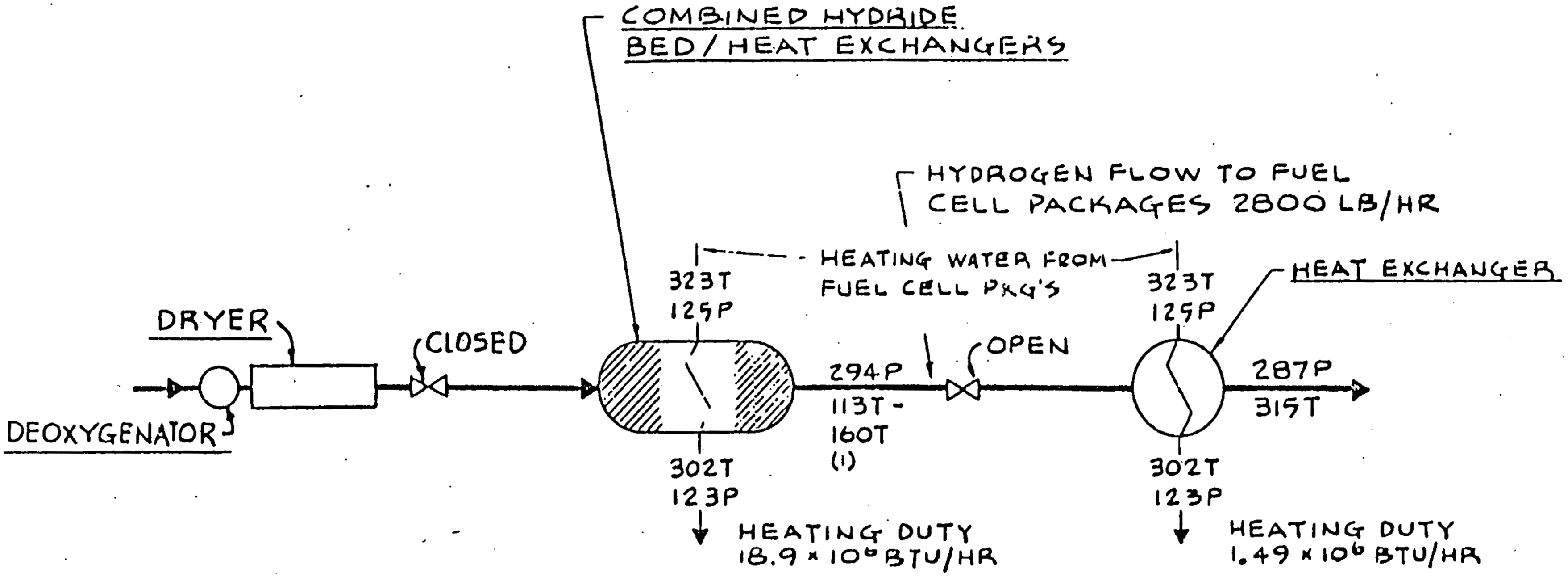
(1) BASED ON HYDRIDING FROM $FeTiH_{0.2}$ TO $FeTiH_{1.4}$

METAL HYDRIDE STORAGE POWER PLANT

HYDRIDING PROCESS SCHEMATIC

FIGURE 2

T= TEMPERATURE °F
P= PRESSURE P.S.I.A.



NOTES
(1) HYDRIDE DISSOCIATION EQUILIBRIUM TEMPS, AT 294 PSIA

METAL HYDRIDE STORAGE POWER PLANT

DEHYDRIDING PROCESS SCHEMATIC

FIGURE 3

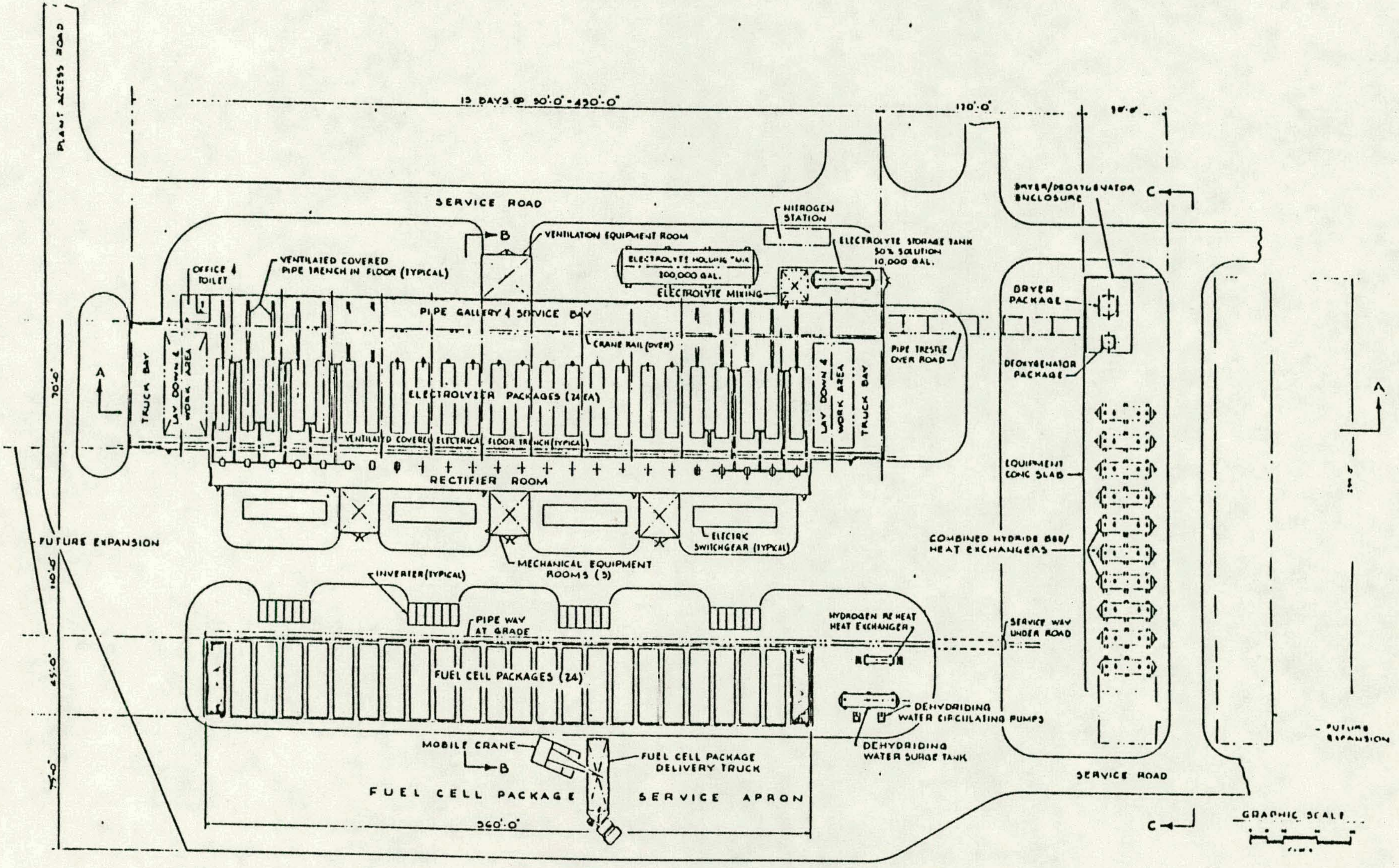


FIGURE 4
Metal Hydride Storage Power Plant - General Arrangement

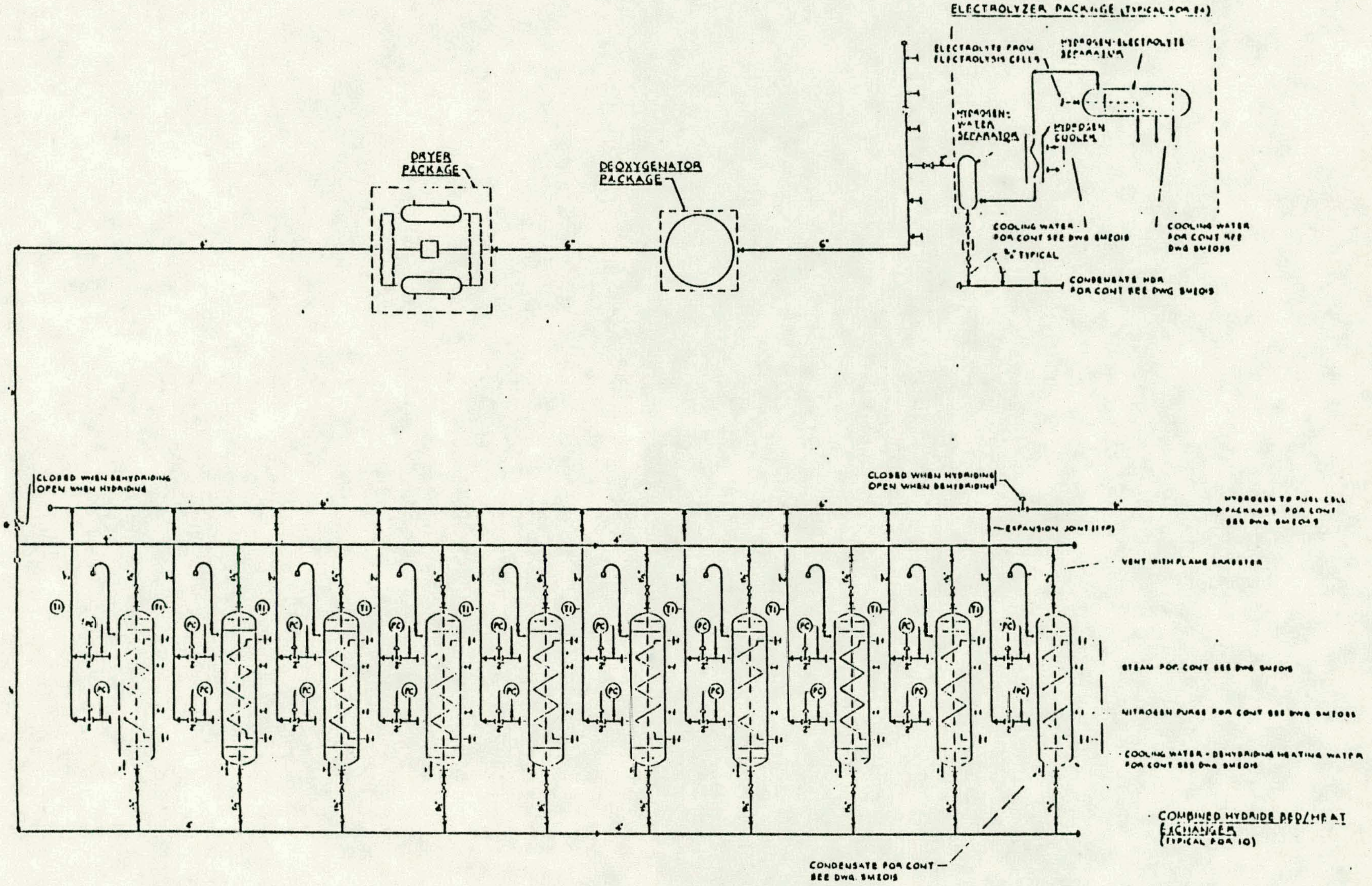


FIGURE 5

Metal Hydride Storage Plant - Hydrogen Flow Diagram

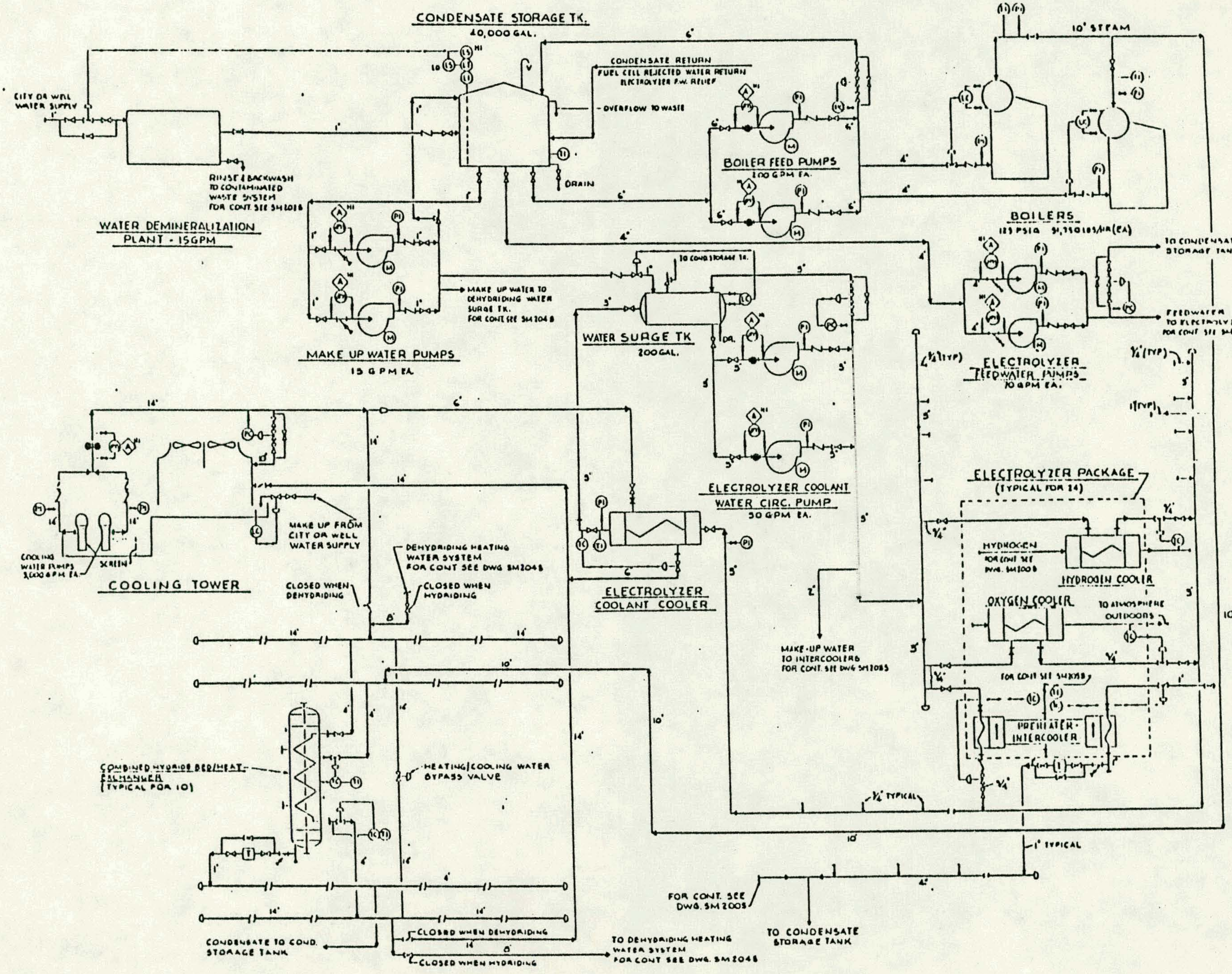


FIGURE 6
Metal Hydride Storage Power Plant - Water and Steam Flow Diagram

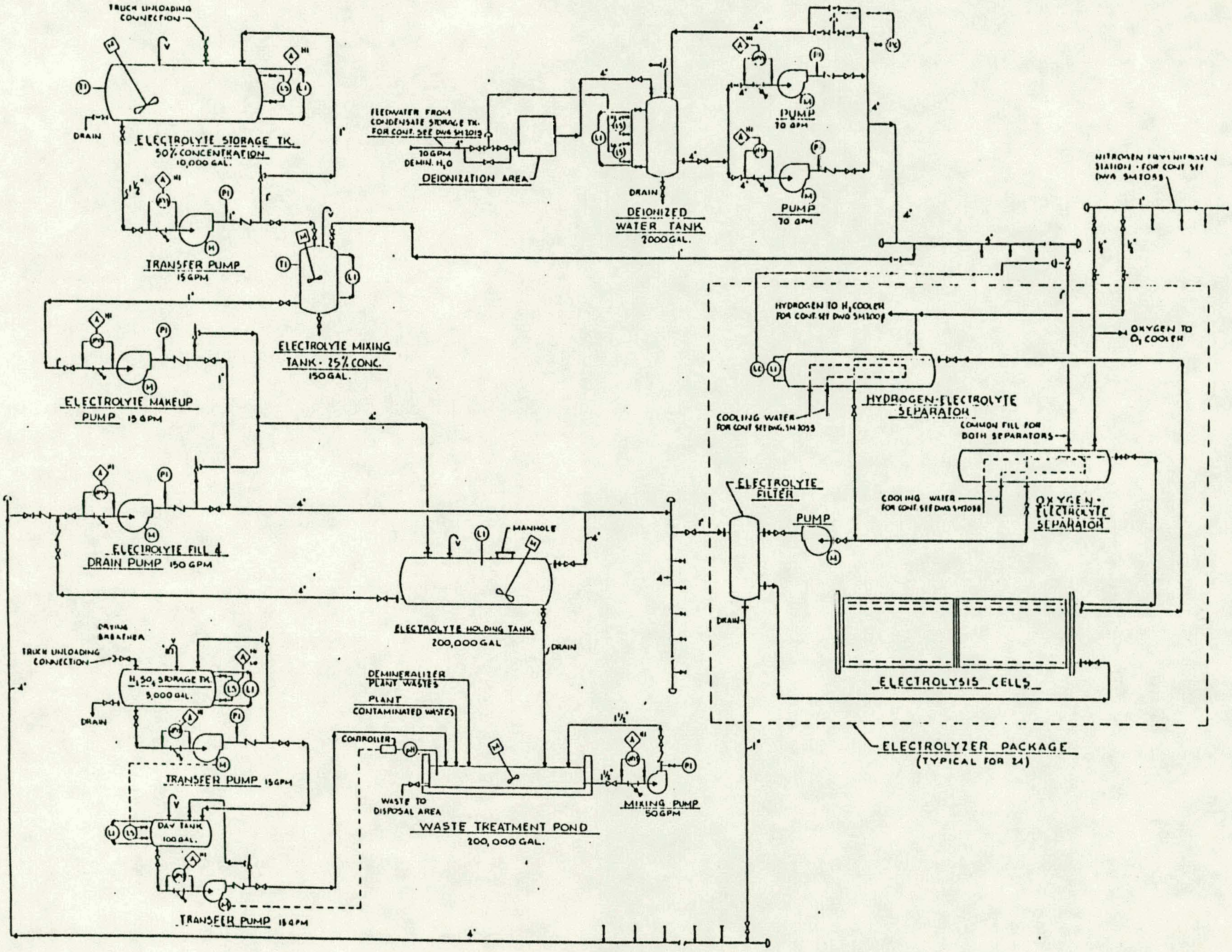


FIGURE 7

Metal Hydride Storage Power Plant - Electrolyte Flow Diagram

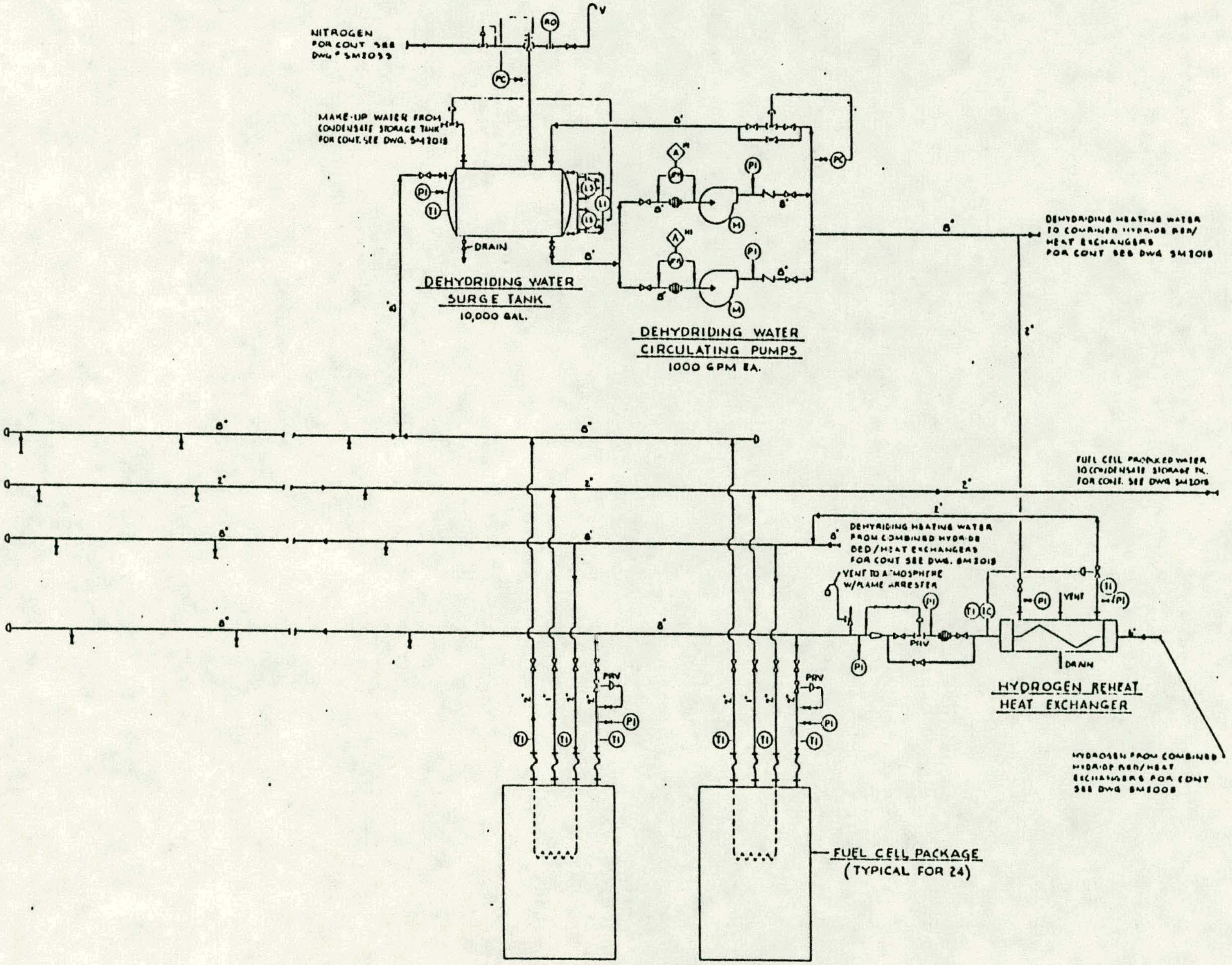


FIGURE 8

Metal Hydride Storage Plant - Fuel Cell Package Piping Diagram

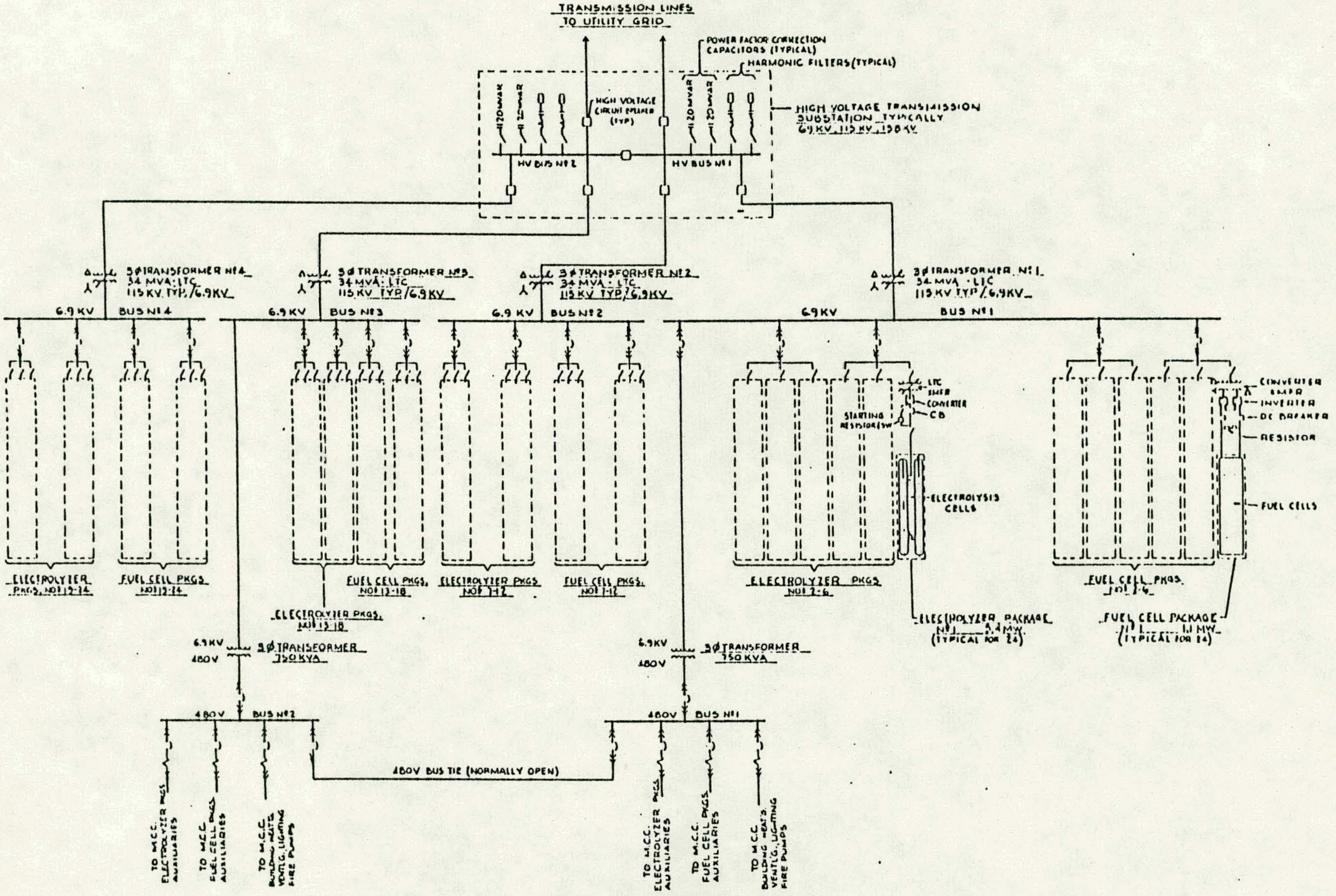
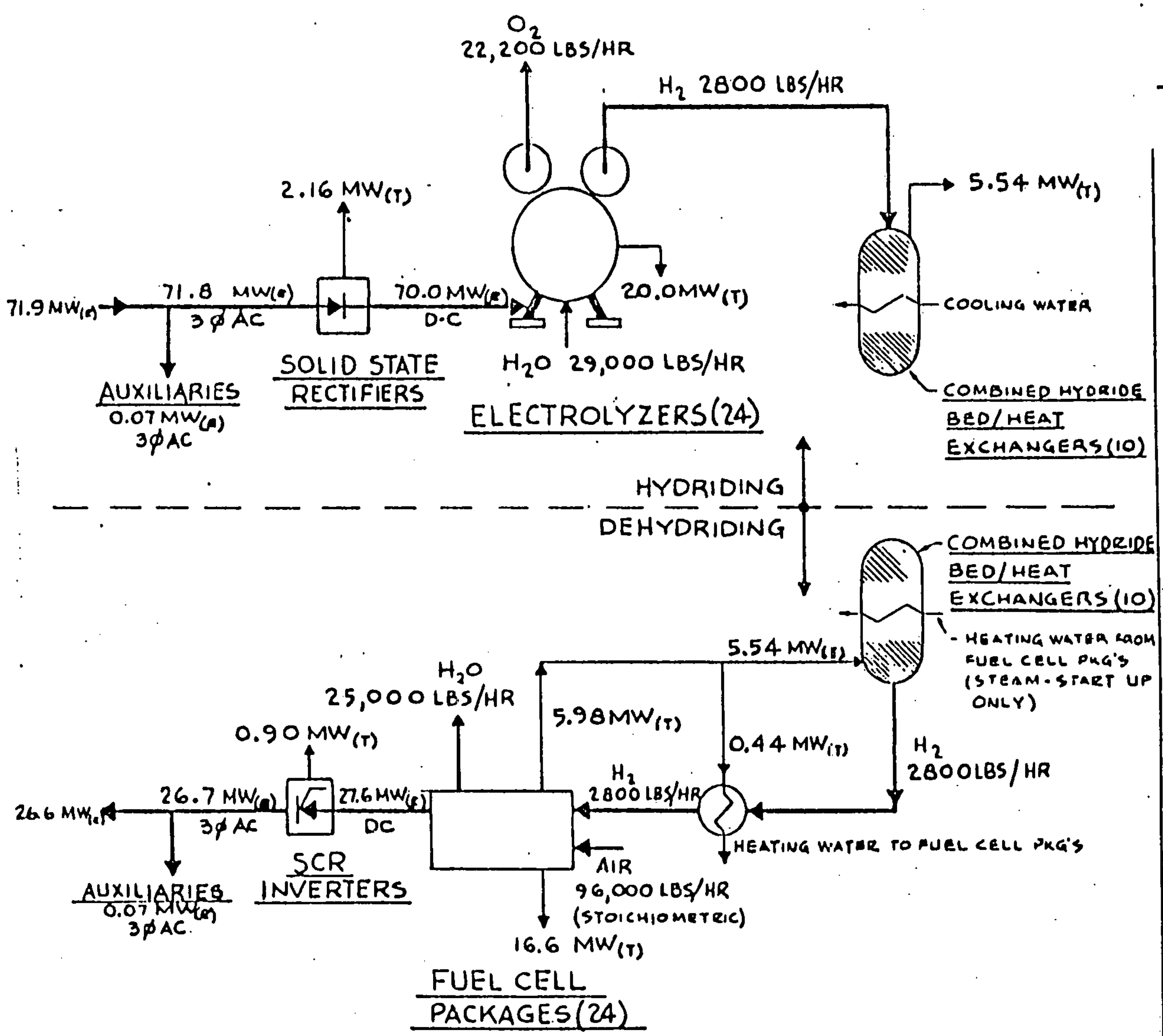


FIGURE 9

Metal Hydride Storage Power Plant - Main Electrical One-Line Diagram



METAL HYDRIDE STORAGE POWER PLANT

ESTIMATED NOMINAL PLANT PERFORMANCE

(CONDUCTION CASE)

HYDRIDING

RECTIFIER INPUT	71.8 MW
AUXILIARIES - (COOLING TOWER PUMPS, OTHER PUMPS, ETC.)	0.07 MW
TOTAL PLANT INPUT	71.9 MW
RATE OF H_2 ENERGY STORAGE (BASED ON HHV OF H_2)	50.1 MW
NOMINAL HYDRIDING EFFECTIVENESS	$\frac{50.1}{71.9} \times 100 = 70\%$

DEHYDRIDING

GROSS PLANT OUTPUT	26.7 MW
AUXILIARIES - (HEATING WATER PUMPS, FUEL CELL EXHAUST FANS, ETC.)	0.07 MW
NET PLANT OUTPUT	26.6 MW
RATE OF H_2 ENERGY AVAILABILITY (BASED ON HHV OF H_2)	50.1 MW
NOMINAL DEHYDRIDING EFFECTIVENESS	$\frac{26.6}{50.1} \times 100 = 53\%$

OVERALL PLANT EFFICIENCY

$(0.70)(0.53) \times 100 = 37\%$

FIGURE 10

Metal Hydride Storage Power Plant - Estimated Nominal Plant Performance

FIGURE 11

THE BREAK EVEN CAPITAL COSTS OF THE BLACK-BOX STORAGE DEVICE, AS A FUNCTION OF THE CONVERSION EFFICIENCY

NOMINAL PEAK LOAD DISTRIBUTION
DISTILLATE FUEL OIL PRICE OF $2.6/10^6 BTU

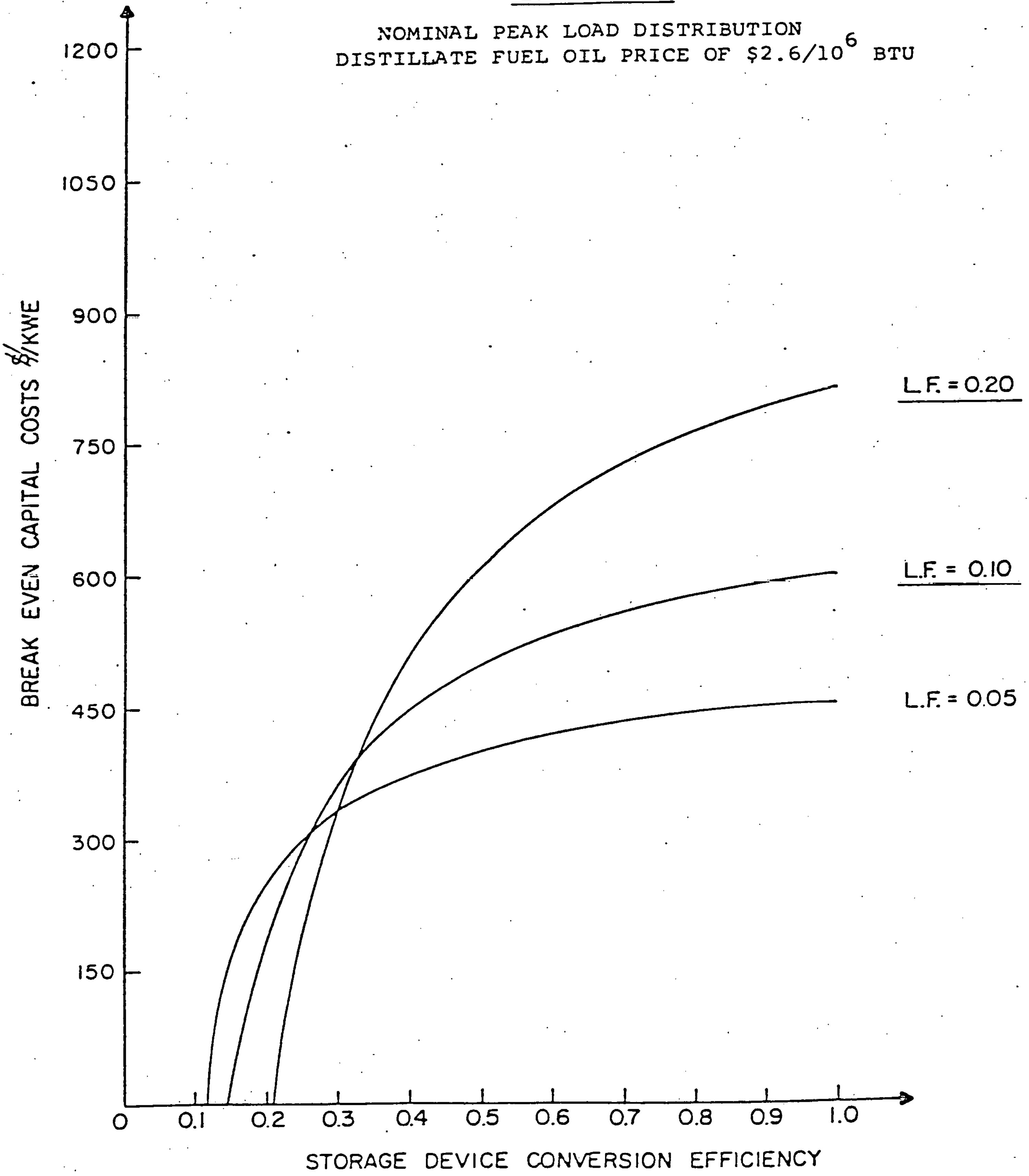


FIGURE 12

THE BREAK EVEN CAPITAL COSTS OF THE BLACK-BOX STORAGE DEVICE, AS A FUNCTION OF THE CONVERSION EFFICIENCY

NOMINAL PEAK LOAD DISTRIBUTION
DISTILLATE FUEL OIL PRICE OF $3.9/10^6 BTU