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**HYDROGEN PRODUCTION
FROM SMALL HYDROPOWER SITES
FINAL REPORT**

April 1980

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DIVISION OF THERMAL AND MECHANICAL STORAGE
OFFICE OF ADVANCED CONSERVATION TECHNOLOGIES
UNITED STATES DEPARTMENT OF ENERGY

DEPARTMENT OF ENERGY AND ENVIRONMENT

**BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973**

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FINAL REPORT

HYDROGEN PRODUCTION FROM SMALL HYDROPOWER SITES

AIR PRODUCTS AND CHEMICALS, INC.
ALLENTOWN, PENNSYLVANIA 18105

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ABSTRACT

In a U. S. Department of Energy sponsored program under the administration of Brookhaven National Laboratory, Air Products and Chemicals, Inc. has studied the commercial feasibility of producing hydrogen with electrolytic cells powered by electricity generated from a small hydropower site. This study was undertaken as a result of a favorable feasibility assessment of hydrogen production from small hydropower sites completed by the Institute of Gas Technology in June 1978 for the Department of Energy.

The complex scope of the current study precludes a brief and comprehensive abstraction of the study results. The preliminary engineering and economic evaluation included the analysis of electrical and hydrogen production systems under two commercial hydrogen supply options. The study plan was designed to allow independent analysis of the economics of electrical power production and hydrogen production, and conclusions about the combined concept. Summary conclusions about the combined facility concept follow.

A synergistic relationship was not found to exist between low-head hydropower and electrolytic hydrogen production. The "storageability" of hydrogen was expected to mitigate problems of hydrogen generation variability associated with the use of low-head hydropower as the power source. The expense of gaseous hydrogen storage equipment effectively eliminates storage as a means to decouple hydrogen demand and power/hydrogen production. From the opposite perspective, the availability of a low and stable cost of power from low-head hydro was expected to improve the competitiveness of electrolysis. In actuality, the results indicated that hydroelectric power from small dams would be comparatively expensive by

current grid power standards (mid-1979). Furthermore, electrolysis, in the capacity range considered here, is less sensitive to the cost of the power than originally presumed. Other costs including depreciation and capital related charges are more significant. Finally, due to power generation variability, sole reliance on low-head hydropower to provide electricity to the cells would reduce the utilization of the hydrogen production investment, resulting in an increase in unit production costs.

These factors were paramount in the Air Products recommendation to discontinue the study before continuing to more detailed stages of analysis, including an analysis of a site specific facility and the construction of a demonstration facility. Another major factor was the unavailability of a pipeline hydrogen supply situation which, because of lower distribution and capital costs, could have been commercially viable.

An unfavorable judgment on the combined facility should not be misinterpreted and extended to the component systems. Although a detailed analysis of the individual prospects for electrolysis and low-head hydropower was beyond the study scope, the reader will realize, as the study is reviewed, that each is worthy of individual consideration.

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

The objective of this study was the preliminary design, engineering, and evaluation of the commercial prospects of a small hydroelectric, electrolytic hydrogen facility. Two commercial options were considered for the proposed facility. The preferred option involved locating a suitable hydrosite and a large volume hydrogen user in close enough proximity for hydrogen supply via pipeline. The economics favored the "on-site" approach since it would involve substantially lower distribution costs. The alternative approach was the supply and distribution of smaller quantities to numerous customers regionally, involving the relatively expensive distribution of the gas by tube trailers. Based on the study results, Air Products has concluded that neither commercial option is viable in the Northeast and has recommended that the study be discontinued before proceeding to more detailed engineering and, possibly, construction activities. The basis for the recommendation to discontinue the study was the high estimated cost of low-head hydropower, the lack of an on-site opportunity, and the unfavorable economics of a electrolytic merchant hydrogen facility.

Study participants included General Electric, Inc. and Electrolyzer, Ltd., respective suppliers of Solid Polymer Electrolyte (SPE) and Stuart electrolytic cells; Allis-Chalmers, a manufacturer of hydro-turbine/generator systems; and Essex Development Associates, Inc., a firm with low-head hydropower development experience.

1.2 FACILITY DESCRIPTION

The facility envisioned consisted of a low-head hydropower site with an installed capacity of approximately 1700 KW powering the electrolytic cells (1500 KW) and auxiliary equipment. The facility would generate approximately 99.4 MMSCF* of hydrogen annually to serve the hydrogen chemical requirements of users in the Northeast. Approximately 1000 KW of the installed hydrogen production capacity would consist of cells provided by the Electrolyzer Corporation, Ltd. The balance of the electrolysis capacity would be provided by the General Electric SPE cell which is currently under development and is projected to have a relatively low installed capital cost and conversion efficiency exceeding the capability of existing systems. Turbine generators, manufactured by Allis-Chalmers and developed especially for low-head applications, would have been used for the production of hydroelectric power.

1.3 STUDY DESCRIPTION

The original study plan consisted of three phases, Phase I, Systems Analysis, Phase II, Site Selection, and Phase III, Site Engineering and Economics. During Phase I, the probable costs of electrical power from a hypothetical low-head hydropower site were investigated. A preliminary capital and operating cost estimate of the hydrogen production facility based on general design and site parameters was prepared for the on-site and merchant options. A sensitivity analysis was also conducted on the major cost components.

*million standard cubic feet (68°F, 14.7 psia)

A market concentration and distribution cost analysis was also performed during Phase I. The relationship between unit distribution costs and shipping distance was examined. A pipeline distribution cost analysis was undertaken to define the distance limits for cost effective pipeline distribution. The market analysis identified potential on-site users, and the geographical concentration of hydrogen use in New England, which would be important in selecting a site for the merchant plant.

Phase II, Site Selection, involved locating potential hydropower sites using U.S. Army Corp of Engineers dam inventory and New England Hydropot information. The preferred dam sites were evaluated and cost of power estimates were prepared.

Phase III, Site Engineering and Economics would have involved the preparation of a budget cost estimate for the proposed facility at an actual location based on a preliminary site engineering. This phase was not undertaken due to study discontinuation.

1.4 STUDY RESULTS

1.4.1 LOW-HEAD HYDROPOWER

The hydroelectric portion of the base case analysis assumed an installed capacity of approximately 1700 KW, a 30 foot head, new generating equipment, and rehabilitated civil works.

According to the base case analysis, the cost of power from low-head hydropower is likely to range from 38 mils to 79 mils under an industrial development scenario depending on capital investment and capacity utilization. Few sites in the low part of the range would be available since the extremely favorable hydrologic conditions assumed are uncharacteristic

of low-head hydropower. Generating power at the lower cost requires the uncommon situation where a turbine is sized to accommodate the minimum flow and can operate over 90% of the time. This situation results in minimal capital costs which are economically absorbed by large KWH production. The higher costs of power are more likely and are largely due to significant capital costs per KW and flow variation which usually reduces capacity utilization to between 40 and 60 percent. A sensitivity analysis confirmed that capacity utilization was a key factor in hydropower costs.

In Connecticut and Massachusetts, which were isolated as the best locations for the proposed facility based on hydrogen marketing considerations, electricity was less expensive from the power grid in the base year (mid-1979) and continued to be less expensive through 1989 except under a scenario most favorable to the hydropower. Generally, low-head hydropower, even with its low escalation rate, cannot reach equivalence with the faster escalating grid costs because grid power is significantly less expensive in the base year. Nevertheless, low-head hydroelectric power from the larger sites should be more attractive to public utilities which can finance hydro using a lower cost of capital and can be competitive with other new generating sources, especially in view of the low escalating characteristic of hydropower costs.

1.4.2 SITE SELECTION

Site selection activities were unsuccessful in identifying a dam which was available for development and could serve an on-site hydrogen customer. Army Corp of Engineers dam inventory and New England Hydropot information was reviewed along with hydrogen user lists. The only possibility discovered was in Pawtucket, Rhode Island, where there was a dam site of sufficient generating capacity to serve a nearby prospect. Unfortunately, the owner of the lower Pawtucket dam, Blackstone Valley Electric, is considering recommissioning the site and it was not available for the program.

Essex Development Associates, Inc. identified 9 other potential sites, four of which were evaluated. Based on an earlier study conclusion that capacity utilization was a major factor in cost of electricity, only sites which offered high utilization were selected for evaluation from the ten sites identified. The cost of service ranged from 45 mills to 95 mills per KWH and was, as our base case analysis indicated, extremely sensitive to investment and capacity utilization. Essex calculated that three of the sites could produce power in the range of 45-57 mills. The fourth site required substantial investment and offered a higher cost of power, estimated at 95 mills.

1.4.3 ELECTROLYTIC HYDROGEN

The base case hydrogen plant had a capacity of 99.4 MMSCF/year. Electrolyzer cells provided approximately 64 percent while General Electric SPE cells contributed 34 percent of the capacity. Two plant configurations were developed corresponding to the on-site

and merchant options under consideration. A hybrid plant serving an on-site customer with its base load and the merchant market with the balance of production was a third possibility and would have been considered explicitly if such a situation arose.

The investment estimate for the on-site configuration was \$1,764,000, excluding the hydropower station and pipeline. The merchant plant estimate was approximately \$4.4 million. The larger investment reflected the cost of additional compression, clean-up, and storage equipment associated with the merchant plant configuration. The investment amounts included the development of an unimproved parcel of land into an operating hydrogen production facility. In this respect, the estimates here are conservative. Economies would be present to the extent that an actual site may have already been partially developed and may contain existing buildings which could house the cells and peripheral equipment. An investment sensitivity analysis later in this report will allow for capital cost adjustments.

The cost per CSCF* of hydrogen from the on-site facility was estimated at approximately \$.91, of which electrical costs assuming 31 mil power (Connecticut grid in mid 1979) equaled approximately 48 percent. Assuming power cost approximating low-head hydropower (69 mills/KWH, Base Case 2), the cost of the gas rises to an uncompetitive \$1.43/CSCF.

*hundred standard cubic feet (68°F, 14.7 psia)

The cost per CSCF of hydrogen from the merchant facility was estimated at an uncompetitive \$1.62 (F.O.B. the plant) assuming power was available at 31 mills grid rate (Connecticut mid-1979). In this case, approximately two-thirds of the cost are capital related reflecting the greater capital intensity of the merchant plant configuration. With power costed at 69 mills, the cost of hydrogen rose to \$2.19/CSCF. Existing sources of merchant hydrogen in the New England area are approximately \$.90 per CSCF (F.O.B.).

1.4.4 SUMMARY CONCLUSION

The two premises on which this study was based were (1) that the cost of electrolytic hydrogen production was largely the cost of electrical power and (2) that low-head hydropower would be a low cost source of energy which would improve the competitiveness of electrolysis vis-a-vis alternative hydrogen production methods. The study analysis did not support these premises.

The cost of hydrogen production from the base case electrolytic hydrogen plant with an annual capacity of approximately 100 MMSCF was capital intensive. The capital costs of the on-site and merchant configurations were estimated at 47 and 65 percent, respectively, of the total hydrogen production costs. The balance of the costs were essentially the cost of electricity. Consequently, power cost reduction would effect hydrogen production costs less significantly than originally anticipated.

Nor did hydropower appear to offer power cost savings. The base case hydropower cost analysis indicated that the cost of electricity from this source ranged from 38 to 79 mills/KWH. Estimates from actual

site investigations ranged from 45 to 95 mills/KWH. Grid power costs in mid 1979 were approximately 31 to 45 mills in Connecticut and Massachusetts, respectively, areas which would have been desirable locations for the proposed facility based on market proximity factors. Furthermore hydropower cost equivalence with grid power, under the most favorable scenario, will not occur until 1983. The major reason for the relatively high cost of hydropower is the low capacity utilization associated with typical hydrologic conditions.

The commercial development option which had the greatest prospects for competitiveness was the on-site facility because it would involve lower distribution costs than the merchant facility. A thorough investigation of existing hydropower site locations in New England was conducted and each site location was compared to a list of potential prospects for on-site hydrogen supply. The only possible match (Lower Pawtucket) was eliminated due to the unavailability of the site. An on-site situation search was also conducted for the Patterson area. Although there was a large number of users in the vicinity, a pipeline supply situation was not found.

As an alternate to the on-site option, the prospects for commercial success of the proposed facility configured as a merchant plant, were investigated. Due to its surprisingly high capital intensity, a merchant electrolytic plant with annual production capacity of 100 mmscf was uncompetitive. Even if the power were "free", the

estimated cost of hydrogen (\$1.18/CSCF) would exceed the cost of hydrogen from existing merchant sources (\$.90/CSCF) by a factor of 30 percent.

Based on the lack of an on-site opportunity and the unfavorable economics of the proposed merchant facility, Air Products recommended discontinuation of the study and did not select an actual hydropower site for the purposes of preparing a preliminary budget cost estimate.

2.0 STUDY INTRODUCTION

2.1 OBJECTIVE

The objective of this study was the preliminary engineering and economic evaluation of an electrolytic hydrogen production facility using low-head* hydropower as the source of the electrical energy. The hydrogen produced would be marketed to small industrial users. Two development options were explored. Conceptually, the "on-site" electrolytic facility was located near a low-head hydropower site in close enough proximity to a customer (with requirements approximating the plant's capacity) for economical hydrogen distribution via pipeline. The second option, a merchant hydrogen facility, involved the supply and distribution of smaller quantities to numerous customers regionally using tube trailers. The preferable on-site approach offered greater prospects for competitiveness, due to lower distribution costs.

2.2 STUDY ORIGIN

This study was one of two "hydrogen from falling water" programs which were initiated by Brookhaven National Laboratory and the United States Department of Energy as a result of an Institute of Gas Technology (IGT) feasibility assessment of this concept. The IGT study recommended the implementation of an "experimental prototype hydrogen from falling-water facility for engineering evaluation and as a convincing demonstration of feasibility". The second study was undertaken by New York State Energy Research and Development Authority (NYSERDA) at a specific site in Pottsdam, NY.

*Generally refers to hydropower facilities with a net generating head of less than or equal to 60 feet.

2.3 STUDY TEAM

Air Products and Chemicals, Inc. was the prime contractor for this study. Air Products developed and implemented commercially the "on-site" industrial gas supply approach and is the leading commercial supplier of hydrogen in the United States. Subcontractors in this study included the General Electric Company and Electrolyzer, LTD., respective suppliers of Solid Polymer Electrolyte (SPE) and Stuart electrolytic cells; Allis-Chalmers, Inc., a manufacturer of hydro-turbine/generator systems; and Essex Development Associates, Inc. a firm with low-head hydropower development experience. General Electric and Electrolyzer provided cost estimates and engineering data for the electrolytic cells. Allis-Chalmers provided turbine cost estimates based on flow duration curves which were developed by Air Products for the base case analysis. Essex Development Associates, Inc. was the consulting firm which was primarily responsible for hydro-site identification and evaluation.

2.4 PROGRAM PLAN OVERVIEW

The program plan consisted of three major phases. In Phase I, an engineering and economic analysis of power production and hydrogen production for a base case hydropower, electrolytic hydrogen facility under the two development options was performed. A sensitivity analysis of the major cost components of electricity generation and hydrogen production was part of this analysis. The purpose of this phase was to identify the most important cost components which, together with a hydrogen distribution and market concentration analysis, would facilitate the selection of a suitable hydro-site for commercial development.

Phase II, Site Selection, involved the identification and evaluation of potential sites for the proposed facility. The anticipated location for the facility was the industrialized New York/New England region where there are many potential hydropower sites. From a marketing perspective, this region provided opportunities for both types of facilities (on-site and merchant).

In Phase III, Site Engineering and Economics, a preliminary budget cost estimate for an actual facility was planned and would have included definitive estimates of power, hydrogen production and distribution costs. As will be discussed in Section 8.0, the study was discontinued before Phase III due to the unavailability of an on-site opportunity and the uncompetitiveness of a merchant hydrogen facility.

2.5 STUDY AND REPORT ORGANIZATION

The sequence of the study task execution departed from the three consecutive phase approach suggested above. The market concentration study and the distribution and the hydropower cost analyses were undertaken initially to provide the parameters for site selection. Site selection and the hydrogen production economic analyses were then undertaken.

The hydropower and hydrogen production cost analyses were evaluated separately; i.e., a grid power rate was used in the cost of hydrogen analysis. Separate treatment allowed individual conclusions about

each component and facilitated study execution. Sensitivity analyses were performed to evaluate the cost of hydrogen from a combined hydropower electrolytic hydrogen facility.

This report first presents the hydropower analysis and the results of the site selection activities. The hydrogen production economics are then presented. Marketing and distribution cost results follow. Study conclusions are summarized at the end of the report. Each analytical section is prefaced with a detailed description of the methodology and rationale.

2.6 FACILITY DESCRIPTION

The conceptualized facility under consideration consisted of a low-head hydropower site with an installed capacity of approximately 1700 KW powering the electrolytic cells (1500 KW) and auxiliary equipment. This capacity was chosen to take advantage of hydro scale economies minimizing power costs and also hydrogen costs (power costs @ 31 mills equal 47% of on-site hydrogen costs). The power generated could produce approximately 99 MMSCF of hydrogen annually, a production rate which offers scale economies in electrolysis as well. Despite the possibility of producing lower power costs, larger hydro sites were not considered because of licensing problems, general shortages of larger sites (reducing the probability of on-site situation), and market considerations. If an on-site situation near a larger site did arise, the larger hydrogen capacity production would be in the range where steam reforming economics are superior. Alternatively, the merchant market would be unable to absorb the larger quantities of hydrogen

unless the cost of the gas was considerably lower than expected.) The facility would generate approximately 99.4 MMSCF of hydrogen annually to serve the hydrogen requirements of users in New England.

Approximately 1000 KW of the installed hydrogen production capacity consisted of cells provided by the Electrolyzer Corporation Ltd. The Electrolyzer cells have the lowest installed cost and highest efficiency of systems, currently available commercially. The excellent service life of ten years was an additional factor in the selection of this cell to provide the base load production capacity. The balance of the capacity would consist of General Electric SPE cells which are currently under development and are projected to have a relatively low installed capital cost and a conversion efficiency in excess of cells currently available. Air Products and General Electric had agreed to incorporate two 250 KW prototype cells in the proposed facility. Tube^R Turbines, manufactured and developed by Allis-Chalmers, Inc. especially for low-head applications, were used in the study.

Although the entire Northeast was considered, the New England area was selected as the most favorable location for the proposed facility for two reasons. This region contains hydrogen users whose individual requirements fall within the capacity of the proposed facility, establishing them as on-site customer prospects. Such users are either producing their hydrogen through steam reforming of natural gas or buying liquid hydrogen from a merchant supplier. The New England area presents problems with these existing sources of supply,

thus increasing the likelihood of the proposed facility's commercial viability for on-site supply. First, natural gas prices are high and shortages have been experienced. Since a lack of hydrogen can cause severe disruptions in the applications for which it is used, supply dependability could be a real incentive. On the cost side, high natural gas prices increase the cost of steam reforming and could make electrolysis simply more competitive without considering supply dependability. For the prospect whose current demand is supplied by merchant liquid, the distance of New England from liquid hydrogen production facilities imposes high transportation costs which should improve the competitiveness of a local hydrogen source.

The other main reason for selecting New England was the large number of potential hydro-sites, many of which have been previously developed to provide hydro-mechanical or hydro electrical power. In either case, such sites offer rehabilitation opportunities and the prospect of lower cost of power than a previously underdeveloped site could provide.

Two plant configurations corresponding to the two commercial options were developed and will be discussed in greater detail in Sections 5, 6 and 7. Appendix 1 contains a process description and includes a process flow sheet.

3.0 HYDROPOWER COST ANALYSIS

3.1 BASE CASES: DESCRIPTION AND METHODOLOGY

The base case hydropower analysis began with the derivation of three flow duration curves (Figure 3.1). These curves were derived to represent typical hydrologic conditions in the New England area and to illustrate various equipment configurations which, given a 30 foot head, could accommodate an installed capacity of approximately 1700 KW. Approximately 1500 KW of this capacity was required to power the cells and the balance to auxiliary equipment. The curves were submitted to Allis-Chalmers for the purpose of sizing the turbine units to achieve an optimal amount of annual energy production.

The curve for Base Case 1 depicts the flow at a site with a 30 foot head necessary to produce 1700 KW of power 30 percent of the time using two adjustable blade turbines. With optimum sizing of the turbines, Case 1 provided maximum turndown capability and required the smallest amount of flow. Base Case 2 depicts the flow rate necessary to supply roughly the same amount of power with one adjustable blade turbine. The turbine would be operating at the design point 33 percent of the time with turndown capability to 30 percent of the design flow rate. In Base Case 3, a larger flow of water allowed the installation of one fixed blade turbine, without turndown capability, providing 1700 KW 90 percent of the time.

Figure 3.1. Base Cases: Flow Duration Curves

The three Base Cases were submitted to Allis-Chalmer for equipment specification and cost estimates. The information regarding sizing, performance and cost supplied by Allis-Chalmers was used as a basis for the hydropower cost estimate. The turbines for Case 1 were a 1750 mm and a 1250 mm unit both with five adjustable blades. The turbine in Case 2 was a 2000 mm four adjustable blade unit. The proposed unit for Case 3 was a 2000 mm turbine with four fixed blades. In addition to the turbines, Allis-Chalmers' estimate and related scope of supply included the intake device, draft tubes, speed increaser, generator, governor (adjustable blade cases), and hydraulic pressure system. Switchgear and the main transformers were excluded from the Allis-Chalmers package.

3.2 BASE CASES: HYDROPOWER INVESTMENT

The investment totals for the three Base Cases were developed from the Allis-Chalmer's equipment cost estimates and estimates of construction, engineering and other costs included in Table 3.1. The three Base Cases assumed the presence of a structurally sound dam, existing penstock and control gates, construction of a new powerhouse, and the installation of new turbines and generating equipment.

The estimated capital cost of \$2,091,000 for Base Case 1 is significantly larger than the other cases, which are approximately equivalent. The added investment is primarily due to the larger equipment cost associated with the use of two rather than a single turbine (Base Cases 2 and 3) and the higher cost of installation.

TABLE 3.1

BASE CASES: HYDROPOWER INVESTMENT SUMMARY
(1979 \$'s)

	<u>Case 1</u>	<u>Case 2</u>	<u>Case 3</u>
Equipment	\$1,006,300	\$ 740,600	\$ 708,600
Spare Parts	50,300	37,000	35,400
Operations & Start-Up	25,000	25,000	25,000
Construction	603,700	580,300	564,100
Engineering	120,000	120,000	120,000
Miscellaneous	92,400	76,400	74,500
Reserve - 10%	189,800	157,900	152,800
Builder's Risk Insurance	<u>3,700</u>	<u>3,000</u>	<u>2,900</u>
TOTAL	\$2,091,200	\$1,740,200	\$1,683,300
\$/KW Capacity	\$ 1,248	\$ 1,030	\$ 1,036

3.3 BASE CASES: COST OF POWER

The cost of power for the Base Cases is largely the result of the capital intensity of low-head hydropower generation. In this analysis, a 23% annual capital charge rate (See Table 3.2) to cover depreciation, maintenance, taxes, insurance, general and administrative expenses, and net profit before tax was used to estimate annual fixed charges. An investment tax credit of 20% was assumed (legislation pending).

The 23 percent capital charge rate would be representative of the rate used by most industrial concerns. Special site circumstances could make the use of lower capital charge rate more appropriate for an industrial developer. The availability of state tax exempt revenue bonds and property tax holidays would reduce the fixed cost burden and cost of power. The existence of these types of incentives can have a substantial impact on power costs and would have to be evaluated on a site specific basis.

Table 3.3 presents the estimated power cost associated with each Base Case and exemplifies that the cost of power is a function of investment per KW of installed capacity and capacity utilization. This relationship best explains the respective power costs of the three cases.

TABLE 3.2

APCI CAPITAL CHARGE RATE - HYDROPOWER

Depreciation	6.67%
Taxes & Insurance	2.50
Maintenance	3.00
G&A ¹	1.69
Interest	2.11
NPBT ²	<u>7.03</u>
TOTAL	23.0%

¹14.5% of Operating Costs

²5% after tax return on investment (20% ITC)

TABLE 3.3

BASE CASES: COST OF POWER - APCI
(1979 \$'s)

Production - KWH/yr	6,910,570	6,711,613	12,687,645
KW from generator	1,676	1,690	1,625
Investment - Total	\$2,091,200	\$1,740,200	\$1,683,300
Per KW	\$ 1,248	\$ 1,030	\$ 1,036
Operating Costs - Annual			
Water Rights - 5 mills/KWH	\$ 34,550	\$ 33,560	\$ 63,440
Chems & Lubes - \$1.50/KW-yr.	2,510	2,530	2,440
Labor - 1/2 man	13,000	13,000	13,000
Allocations & Site OVH	13,230	11,340	12,390
G&A (Variable Costs)	<u>4,170</u>	<u>3,900</u>	<u>4,040</u>
Subtotal (Variable Costs)	\$ 67,460	\$ 64,330	\$ 95,310
Fixed Costs	<u>480,976</u>	<u>400,250</u>	<u>387,160</u>
Total - \$/yr	\$ 548,436	\$ 464,580	\$ 482,470
Unit Power Cost-mills/KWH	79.4	69.2	38.0
Capacity Utilization (%) ¹	49.5	47.7	93.8

¹ 8322 hours per year = 100%

The two turbine configuration in Base Case 1 allows a slightly higher capacity utilization than in Case 2, but the additional power produced does not sufficiently absorb, nor justify, the higher fixed cost burden imposed by the incremental investment. The cost of service of Base Case 1 is 79.4 mills versus 69.2 mills in Base Case 2. Base Case 3 presents a highly desirable but uncommon situation where a turbine, essentially sized to accommodate the minimum flow, can operate over 90% of the time. This situation results in minimum capital costs which are spread over maximum power production. Base Case 3 would produce 38 mill power.

3.4 SENSITIVITY ANALYSIS: HYDROPOWER BASE CASE

Numerous sensitivity analyses were performed on the Base Case hydropower analysis to understand the relationship between cost of power and significant hydropower cost factors. The results of the various sensitivity analyses were used to develop site selection criteria.

3.4.1 SENSITIVITY TO CAPACITY UTILIZATION

The importance of high capacity utilization in reducing the estimated cost of power from a low-head hydropower installation is clearly demonstrated in Figure 3.2. The unit cost of power is lowered significantly at high capacity utilizations due to the absorption of fixed costs by a large volume of KWH production. This analysis confirmed the conclusion from the three Base Cases that high capacity utilization was the key factor in reducing the cost of power and highlighted its importance in site selection.

3.4.2 UTILITY FINANCING

The analysis of the three Base Cases assumed ownership and financing by an industrial company such as Air Products. The Base Cases were also examined assuming utility ownership and financing. The ownership issue had implications for determining the capital charge rate to be applied to the investment to calculate annual fixed charges. Table 3.4 presents the capital charge rate calculation assuming utility ownership and financing. The 6 percent difference between private industry ownership (23 percent) and the 17 percent calculated for the utility is essentially due to the use of a longer depreciable life and increased financial leverage by a utility. Given the capital intensity of power generation, the lower capital charge significantly reduces the cost of power. Table 3.5 replicates the cost of power calculation for the three Base Cases using a 17 percent rather than the 23 percent rate assumed under private industry ownership (Table 3.3). This analysis suggests that the availability of low interest financing would encourage the development of low-head hydropower by industrial or private developers. Recent legislation which supports an increased investment tax credit of 20% (assumed in this analysis) for low-head hydropower would have a similar impact.

Figure 3.2. Power Cost Sensitivity to Capacity Utilization

TABLE 3.4

UTILITY CAPITAL CHARGE RATE

Depreciation	3.33%
Taxes & Insurance	2.50
Maintenance	3.00
G&A ¹	1.24
Interest	3.35
NPBT ²	<u>3.58</u>
TOTAL	17.0%

¹14.5% of Operating Costs

²15% after tax DCF return on equity (20% ITC)

TABLE 3.5

BASE CASES: COST OF POWER - UTILITY
(1979 \$'s)

	<u>Case 1</u>	<u>Case 2</u>	<u>Case 3</u>
Production - KWH/yr	6,910,570	6,711,613	12,687,645
KW from generator	1,676	1,690	1,625
Investment -	\$2,091,200	\$1,740,200	\$ 1,683,300
Operating Costs - annual			
Water Rights - 5 mills/KWH	\$ 34,550	\$ 33,560	\$ 63,440
Chems & Lubes - \$1.50/KW-yr.	2,510	2,530	2,440
Labor - 1/2 man	13,000	13,000	13,000
Allocations & Site OVH	13,230	11,340	12,390
G&A (Variable Costs)	<u>4,170</u>	<u>3,900</u>	<u>4,040</u>
Subtotal (Variable Costs)	\$ 67,460	\$ 64,330	\$ 95,310
Fixed Costs	<u>355,500</u>	<u>295,830</u>	<u>286,160</u>
Total Costs	\$ 422,960	\$ 360,160	\$ 381,470
Unit Power Cost-mills/KWH	61.2	53.7	30.1
Capacity Utilization (%) ¹	49.5	47.7	93.8

¹ 8322 hours per year = 100%

3.4.3 SENSITIVITY TO CAPITAL INVESTMENT

The capital cost estimates for the three Base Cases assumed the presence of a structurally sound dam, usable penstock and control gates, new powerhouse construction, and the installation of a new turbine(s) and generating equipment. The capital cost sensitivity was developed by including "rehabilitation" and "excessive restoration" development scenarios for each of the three Base Cases. The rehabilitation scenario assumed that existing turbine(s), generator(s), and civil structures could be refurbished. In addition to new generating equipment and powerhouse required in the Base Case formulations, the excessive restoration scenario assumed extensive dam repairs, new penstocks and gates, and fish ladders for environmental reasons. Table 3.6 summarizes the investment and cost of power estimates for the various capital cost situations under each Base Case assuming both private industry and utility ownership. Figure 3.3 graphically illustrates the results of this sensitivity. Clearly, the cost of power is heavily influenced by the capital investment necessary to redevelop a former generating site.

This sensitivity analysis suggests alternatives concerning federal grants to encourage low-head hydropower development. Assuming that the objective of a federal low-head hydropower funding program is to maximize the rate of development of this energy alternative within the constraint of limited funds, such funds should be allocated based on the type of low-head development or redevelopment anticipated and the degree to which the funding is needed to provide a reasonable cost of power. For example, in all three Base Cases, the rehabilitation

scenario delivers power at a cost which is competitive with the cost of grid power. External funding of sites which only required rehabilitation would merely serve to provide higher profits to the lucky developer rather than to encourage development which, according to the economics, would be justifiable entirely within the private sector. Federal funds would be better spent to encourage development of the less economically attractive hydro-sites. With this approach, funds could be directed where the need is the greatest and low-head hydropower development would occur more rapidly. Another approach which would yield the same results would be the use of federal funds to subsidize certain portions of specific site requirements. For example, fish ladders add substantial capital costs which can preclude a site's development.

3.5 POWER COST COMPARISON: BASE CASE VS. UTILITY

A comparison between the Base Case hydropower cost and Connecticut and Massachusetts utility power costs was conducted. These states, particularly the industrial areas surrounding Hartford and Boston, were chosen because of their proximity to the hydrogen market. In mid 1979, the base year, Massachusetts and Connecticut power rates were 45 and 31 mills, respectively. The hydropower costs from the three Base Cases were chosen for the comparison.

Figure 3.3. Power Cost Sensitivity to Capital Costs Graph

Figure 3.4. Power Cost Comparison:
Base Cases versus Utility

Figure 3.4 presents the comparison through 1990. Four utility power cost curves are presented, two for each state assuming rates escalating at 6 and 8 percent. The hydropower cost only escalates at an 8 percent rate on variable costs. Base Case 3, the most optimistic hydropower scenario (90% capacity utilization), would deliver power less expensively than grid power in Connecticut in 1983, assuming the higher escalation rate of 8 percent for the latter. If Connecticut grid power escalates at 6 percent, Case 3 cost equivalence does not occur until 1989. Case 1 and 2 are virtually uncompetitive with either Connecticut or Massachusetts grid costs (mid-1979).

Based upon this comparison, it is unlikely that an industrial user of electricity would be inclined to develop low-head hydropower in the near future without the aid of some type of financial incentive. However, in the future when the gap between low-head hydropower and grid power narrows, an industrial firm would have greater incentive to develop low-head hydropower, provided hydropower capital costs do not escalate at rates which offset the rate of utility power cost escalation.

TABLE 3.6

POWER COST SENSITIVITY TO CAPITAL COSTS SUMMARY

	<u>Case 1</u>			<u>Case 2</u>			<u>Case 3</u>		
	Base Case	Rehab	Excess Rest.	Base Case	Rehab	Excess Rest.	Base Case	Rehab	Excess Rest.
Total Investment (\$000)	2,091	1,045	3,000	1,740	870	2,400	1,683	1,040	2,315
\$/KW Installed	1,248	624	1,790	1,030	515	1,480	1,036	640	1,420
Cost of Power (Mills/KWH)									
APCI	79	44	110	69	39	92	38	26	50
UTILITY	61	35	84	54	31	72	30	17	39

4.0 SITE SELECTION

Essex Development Associates, Inc. assisted and performed the major part of the site identification and evaluation portion of the study. In addition, Air Products reviewed the U.S. Army Corp of Engineers dam inventory and compared it to our proprietary list of current hydrogen user prospects in search of an on-site situation. A description of Essex's approach and the results of both investigations follow.

Essex's approach involved locating river basins in the New England area which had hydrologic characteristics suggesting probable installed capacities of approximately 1500 KW at individual sites assuming generating heads ranging from 20-30 feet. Their calculations indicated that river basins with drainage areas of at least 300 and 450 square miles would be suitable.

This population of basins was then reviewed in light of marketing considerations. Basins in New York, Maine, New Hampshire, and Vermont were eliminated due to distance from hydrogen market concentrations. Proximity to interstate highway network criteria was then used to eliminate remote locations which would portend higher hydrogen distribution costs. The Merrimack Valley in Massachusetts; Connecticut Valley south of Springfield, Massachusetts; certain sections of the Housatonic and Naugatuck Rivers; and some of the smaller basins in Rhode Island were reviewed further. The Passaic River site in Paterson, NJ was included in the investigation because it appeared to offer a low cost of power and a cooperative development environment.

TABLE 4.1

SITE SELECTION: SUMMARY OF PREFERRED SITES

Location	Gross Head	Drainage Area (Sq. Mi.)	Available Flow 25% Time (Cubic Feet/Sec)	Installed Capacity KW	Annual KWH	Capacity Factor	Capital Cost \$/KW	Cost of Service (Mills)
Shelton-Derby, CT	25	1541	3600	1200	9MM	85%	1360	45
Appleton, Lowell, MA	14	4200	*1300 ¹	900	6MM ²	78% ²	1300 ²	57 ²
Paterson, NJ	80	850	1800	7500	37MM	60%	1000	50
Collinsville, CT								
upper	**24	354	800	1245	5.7MM	56% ³	2080	95
lower	***25	354	800	1245	4.2MM			

¹Commercial obligation to provide this flow²New installaton only³Before flow release discussions with HMDC.

Nine sites remained after the initial screening and each was evaluated for development climate, location and development cost factors, and probable cost of power. Development climate issues included licensing constraints, existing ownership interests and environmental protection including hydrogen safety. The proximity of the site to the market and land assembly were also evaluated. Capital costs and capacity utilization were paramount in the cost of power estimates. Of these ten sites, the four offering the highest capacity utilization were designated as the preferred sites. A preliminary cost of service estimate from these four sites ranged from 45 to 95 mills as calculated by Essex's cost of power program.

4.1 PREFERRED SITES

A summary of information for the four preferred sites is presented in Table 4.1. These sites would have been considered as potential sites for the proposed merchant facility, if the economics of electrolytic hydrogen from a merchant plant had been favorable and the program had been continued (See Section 8).

4.1.1 SHELTON-DERBY, CT

The major attractiveness of this site was its central location with respect to the hydrogen merchant market. Furthermore, the large flow of water, relative to the anticipated installed turbine capacity, would allow a high capacity utilization. Capital costs were relatively high due to the need for a new powerhouse and generating equipment, however, the high capacity utilization would compensate and provide power at 45 mills.

This dam, located on the Housatonic River just upstream from its confluence with the Naugatuck River, was first built in the mid 1800's to provide power to mill buildings on the Shelton (west) side of the dam. A canal system and locks still exist today, although the generating equipment has been removed. On the Derby (east) side, a second canal system is still in existence; however, the generating equipment has also been removed. Originally, a 1000 KW generator was on the canal with an additional 7000 KW at the dam.

The present owner of the dam and water rights is Connecticut Light & Power (CLP), which is a subsidiary of North-East Utilities. United Illuminating, a subsidiary of CLP, was the last operator of the dam. The powerhouse, is currently leased by Derby-Hull Dye Co. for storage space. The current uses of the dam are to regulate tailrace elevation at Connecticut Light & Power's hydropower facility at Stevenson Dam, six miles upstream, and to provide for the recreational uses of the impoundment.

The Housatonic River Basin contains 1,541 square miles of drainage area above the Shelton-Derby Dam. The dam is located 16 miles from the mouth of the Housatonic River in Long Island Sound. A 25 foot head is available. The river downstream of the dam is tidal. Flow available at Shelton-Derby is regulated by the discharge from Stevenson Dam. The mean annual discharge is 3000 cubic feet per second (CFS). Major reservoirs upstream include Candlewood, Lillinohah Zoar, Cairns and Shepaug. Lake Housatonic, located behind the dam, is a five mile long impoundment used primarily for recreational boating.

A possible development scenario at this site would involve the construction of a powerhouse adjacent to the lower locks of the canal system in Shelton. This facility would house an adjustable blade, 1500 MM (rated capacity, 1200 KW) tube turbine supplied by Allis-Chalmers. The powerhouse would be partially buried and constructed of reinforced concrete. Since this turbine will only utilize 500 CFS, a very high load factor (80%) could be expected. Annual average output would be approximately 9 million KWH.

The capital cost of this development scenario, as estimated by Essex is \$1,631,000 or approximately \$1,360/KW as shown below.

Equipment	\$ 663,000
Other electrical/equipment	268,000
Civil structures	550,000
Engineering and development	<u>150,000</u>
TOTAL	<u>\$1,631,000</u>

The first year cost of service was estimated by Essex at 45 mills/KWH.

4.1.2 APPLETON MILLS, LOWELL, MA

This site was well situated with respect to the hydrogen merchant market. A high capacity utilization was available and rehabilitation of existing generating equipment was a possibility. However, the low-head suggested higher capital costs if new equipment were necessary.

This site is located on a canal system adjacent to Merrimack River in Lowell, MA. The facility utilizes a head of 14 feet and a flow up to 1,350 CFS from a 4,200 square mile drainage area. Installed capacity is 1 MW made up of four different wheels installed in the 1920's. A joint evaluation with Allis-Chalmers indicated a single standard tube unit rated at 900 KW should be installed to replace the old installation for increased efficiency and output. Operation on the canal system would provide a very high capacity (75%) utilization factor and attendant high KWH production.

The canal system and water rights at this site are controlled by the proprietors of Locks and Canals in Lowell, with annual water rents of approximately \$30,000.

The 900 KW turbine would produce an annual average in excess of 6 million KWH's. An additional 1.5 MM KWH would be possible if one of older units were rehabilitated. Although the installed capacity of 1150 KW was smaller than the 1700 KW expected requirement, the total generation of 7.5 MM KWH would approximate the output of a larger site with a lower and more typical capacity utilization.

The cost of development of the new generating capacity was estimated by Essex to be \$1,170,000 or approximately \$1300/KW.

Equipment	\$ 890,000
Civil structures	160,000
Engineering and development	<u>120,000</u>
TOTAL	\$1,170,000

The resulting cost of power in the first year would be approximately 57 mills.

4.1.3 PASSAIC RIVER FALLS, PATERSON, NJ

The attraction of this site was the prospect of low cost power and the willingness of the city to develop the site in a joint venture with an industrial concern which could attract other industry to the area. Unlike the other preferred sites, this site could have been a potential on-site situation because of its proximity to many local hydrogen users.

The Paterson Dam at Great Falls was first built to power a unique three-tiered canal system designed by Alexander Hamilton. The 325 foot long masonry dam was built above the falls in around the 1830's to obtain a gross power head of approximately 80 feet. The site was used for mechanical power generation until 1914, when the existing powerhouse was constructed at the foot of the falls. This structure contains three 1720 KW and one 1400 KW generators. Major rehabilitation work is required at this site. The existing dam is in poor condition and rehabilitation of the installation will require substantial restoration or, perhaps, a new dam entirely.

Allis-Chalmers has indicated that the efficiency of these old units could be increased by redesigning the blade configuration. Historically, the total installed capacity has been 6.6 MW, but with redesign of the runners, this could be increased to 7.5 MW. The total estimated average annual generation is 32,000,000 KWH. Air Products' discussions

with the City of Paterson focused on securing the development rights for the power from just one of the four turbines which would be rehabilitated to meet the power requirements of the hydrogen facility. Discussions aimed at securing first claim to the flow were unsuccessful but would have resulted in a 90 percent capacity utilization.

The Passaic River Basin contains some 850 square miles of drainage area with an annual mean flow of 1600 CFS. The City of Paterson is currently involved in litigation with an upstream diverter of water. An unfavorable outcome of this litigation would reduce downstream flow and estimated annual power production.

The following economics are for the redevelopment of the full capacity of the site. A total project cost estimate of \$7.5 million including new generating equipment in 1978 dollars was developed by an engineering consultant contracted by the city. More detailed project cost information was not provided by the city. The cost of a new dam is estimated to comprise at least \$1 million of this cost. The city's estimated cost of service was estimated at 25 mills in 1977 dollars, while EDAI projects 50 mills for the first year in 1980 dollars.

4.1.4 COLLINSVILLE DAMS, CANTON, CT

Canton, CT is well situated to serve the merchant hydrogen market and was chosen on this basis. In addition, a relatively high capacity utilization was possible assuming successful negotiation with the Hartford Metropolitan District for controlled water flow releases from upstream reservoirs. Later investigations revealed that the cost of power would be prohibitive, largely due to the high capital cost of

redeveloping the two dams and installing fishways. The Collins Company site consists of two 350 foot long masonry dams located on the Farmington River in North Central Connecticut, approximately 20 miles northwest of Hartford. The upper dam, located adjacent to the original Collins Company factory buildings (now Collinsville Company) was originally a timber crib dam built in the late 1700's to power a saw mill. The Collins Company built the existing dam just downstream of the original wooden dam in 1846. The dam has a total gross head of 21 feet. Three additional feet were achieved with flashboards, which are currently maintained by a local water skiing organization. This site was used for hydromechanical power generation by the Collins Company until the early 1900's when nine Holyoke turbines and generator sets were installed throughout the factory buildings. These units were rated at a total capacity of 1,500 KW. In 1914, the company constructed the lower dam one mile downstream to increase power production. The gross head is 20 feet at this dam, although an additional five feet was available by installing flashboards. The powerhouse is situated 100 yards downstream on the east bank and contained two Allis-Chalmers vertical turbines and generating sets rated at 500 KW each. This equipment has been removed. Further development occurred in 1920 on the west bank of the upper dam with the addition of a new powerhouse, containing a Leffel turbine and 400 KW Westinghouse generator.

After the closing of the Collins Company in 1965, Hartford Electric Light Company (HELCO) purchased the dams and powerhouses, and all equipment. In 1966, the utility gave the facility to the Connecticut

Department of Environmental Protection (DEP). The town Conservation Committee has been authorized by the DEP to redevelop the hydropower site, subject to DEP approval of proposed projects.

Water rights have belonged to the Farmington River Water Power Company since the 1870's. The Collins Company was a major stockholder in the power company, as were the Stanley Works in New Britain and the Greenwoods Company in New Hartford.

Presently, the Hartford Metropolitan District Commission (HMDC) controls flow upstream of the Collinsville sites, subject to maintenance of specific flow requirements necessary for the Stanley Works Rainbow Dam, located 20 miles downstream of Canton.

The Farmington River Basin drainage area above the two dams is 354 square miles, however, upstream reservoirs reduce the drainage area slightly. These impoundments, which include two Corps dams, Colebrook and Otis, and two HMDC dams, Barkhamsted and Compensating, do tend to stabilize river flow. This results in a higher percentage of flow falling within the operational range of the generation equipment and attendant rise in annual output and flow. Successful negotiations with HMDC or flow releases would have further improved the generation potential of the sites.

Historically, the total effective capacity of the two sites has been 2,000 KW. Collins Company figures indicate that at least 7 million KWH was produced annually through the late 1950's. However, all the original generating equipment either has been removed or vandalized, so redevelopment would involve the purchase of new equipment. A feasibility study done by Development and Resource Corporation in 1979 and analysis of flow duration curves by Essex indicated an installed capacity at the upper dam site of 1245 KW, using a 2000 MM Allis-Chalmers standard tube unit rated at 895 KW and a second 1250 MM tube unit rated at 350 KW. Using a capacity factor of 60 percent, annual generation would be 5.7 million KWH for the upper site.

The lower dam would utilize the same two units. However, at this dam the output would be 640 KW and 250 KW, respectively. At this site, annual generation is expected to be 4.2 million KWH for a total (both dams) output of 9.9 million KWH.

Due to the reintroduction of Atlantic Salmon into the Farmington River, the Connecticut DEP had plans to construct a pool and overflow-type fishway at the upper dam and to breach the lower dam. Redevelopment of both hydropower facilities would mean construction of two such fishways. A report prepared by Fisheries Consultant, Milo C. Bell, investigated the most economical possibilities for fishway construction. In this report, fishway costs of \$315,000 for the upper dam and \$360,000 for the lower dam were estimated.

Total project cost estimates prepared by Essex are approximately \$5.2 million or approximately \$2,080/KW as follows:

Equipment - (Upper and Lower Total)	\$3,200,000
Civil - (Power Plant and Civil Works)	850,000
Environmental - Fishway Facilities	675,000
Engineering and Administration 10%	<u>472,000</u>
	\$5,197,000

Essex's computer model projects a cost of service for the first year of 95 mills/KWH in 1979 dollars based on a start of operation in mid-1983 and annual energy production of approximately 10 million KWH.

4.2 THE ON-SITE POSSIBILITY

Air Products' site identification activity resulted in the discovery of one potential situation where there was a dam site of sufficient generating capacity to serve a nearby hydrogen prospect. The site was located in Pawtucket, Rhode Island. Essex was requested to explore the opportunities and reported that the site was not available for the program since the owner of the lower Pawtucket dam, Blackstone Valley Electric, is considering recommissioning the site.

4.3 ESSEX DEVELOPMENT ASSOCIATES, INC. COST OF POWER ASSUMPTIONS

The cost of power estimates provided for the preferred sites were generated from Essex's cost of power program. The costs are for the first year, and change in subsequent years as debt principle is repaid and interest costs decline and maintenance and operations costs increase. The following assumptions were used in the estimates:

Operating Life (years)	37
Long Term Debt Amortization Life (years)	25
Debt/Equity Ratio	80/20
Debt Interest Rate (%)	11
Construction Loan Rate (%)	13
DCF Return on Equity (%)	15
Book Depreciable Life (years)	30
Tax Depreciable Life (years)	30
Tax Rate (%)	50
Investment Tax Credit (%)	7.3-20%

Different investment tax credits were used depending on the nature of the redevelopment. Lower rates were applied to sites which had existing powerhouses and related civil works.

5.0 ELECTROLYTIC HYDROGEN PRODUCTION COST ANALYSIS

Cost estimates for two electrolytic hydrogen facilities were prepared during this study. The first facility assumed an on-site supply situation and the second, a merchant plant configuration. The two facilities were identical in production capacity. Approximately 99.4 MMSCF* of hydrogen would be produced annually from Electrolyzer and General Electric SPE cells from a combined installed capacity of 1500 KW. Electrolyzer and GE cells would account for 1000 KW and 500 KW, respectively. The estimates were based on the same estimating procedures, modified where appropriate, that Air Products employs in its own capital projects. In contrast to other, more academic oriented studies which have focused solely on the purchase price of the electrolytic cells in computing the investment amount, this study estimate includes the costs of valves, instrumentation, piping, electricals, site development, construction, engineering, and start-up. Furthermore, it's important to emphasize that both estimates are generalized and assume that the investment estimates reflects the cost of developing an unimproved property into an operational hydrogen production facility. An individual firm considering "captive" on-site electrolysis would view certain investment items incrementally, lowering capital and hydrogen production costs. The cost of hydrogen calculations assumed a power cost of 31 mills (Connecticut, mid-1979). A subsequent power cost sensitivity analysis allows for product cost estimates based on higher power costs which are more representative of the low-head hydropower base case costs. A capital charge rate of 24.6 per cent was applied to the investment amount to calculate annual fixed charges (See Table 5.0). It differs from the APCI rate of 23 per cent for hydropower investment because it assumes a 10 percent rather than a 20 percent investment tax credit.

*million standard cubic feet (68°F, 14.7 psia)

TABLE 5.0

APCI CAPITAL CHARGE RATE -
ELECTROLYTIC HYDROGEN FACILITY

Depreciation	6.67
Taxes & Insurance	2.50
Maintenance	3.00
G & A ¹	1.69
Interest	2.11
NPBT ²	<u>8.53</u>
TOTAL	24.5%

¹14.5% of Operating Cost

²5% after tax return on investment (10% ITC)

5.1 ON-SITE HYDROGEN FACILITY INVESTMENT

The proposed facility configured for on-site supply would cost an estimated \$1,764,000 (See Table 5.1). The cells account for \$543,000 with auxiliary equipment, including valves, instruments, electricals, compression, etc. contributing an additional \$347,000. Construction and engineering costs are estimated at \$504,000 and \$150,000, respectively. Start-up and training costs of \$36,000 were included.

5.2 ON-SITE HYDROGEN PRODUCT COST

The cost of hydrogen from the on-site facility was estimated at \$.91/CSCF* (Table 5.2). Electrical costs to power the cells and auxiliary equipment was estimated at \$425,670 or 48% of the total. Fixed costs contributed \$432,330.

5.3 MERCHANT HYDROGEN FACILITY INVESTMENT

As estimated in Table 5.3, the merchant facility would cost an estimated \$4,430,000. The cell cost remains the same at \$543,000; however, the equipment cost rises to \$1,760,330. The incremental equipment cost versus the on-site case is largely hydrogen storage equipment (\$820,000), and compression, gas drying, and clean-up equipment costs (\$590,000). The additional equipment costs results in higher engineering (\$233,641) and construction (\$1,218,000) expenses. The G.E. cell cost, as in the on-site case, is G.E.'s estimate of long term projected cost. Common equipment, engineering, construction costs have been largely allocated between the cell systems based on production.

*hundred standard cubic feet (68°F, 14.7 psi)

TABLE 5.1

ON-SITE HYDROGEN FACILITY INVESTMENT
(1979 \$'s)

	<u>G.E.</u>	<u>Elec.</u>	<u>Total</u>
Cells	\$259,000 ¹	\$ 284,000	\$ 543,000
Equipment ²	125,614	221,386	347,000
Spares	18,101	31,894	50,000
Operations	13,033	22,967	36,000
Construction	196,357	307,643	504,000
Engineering	54,301	95,699	150,000
Miscellaneous	18,098	31,902	50,000
Reserve	30,871	49,129	80,000
Builder's Risk Insurance	<u>1,542</u>	<u>2,463</u>	<u>4,000</u>
TOTAL	\$716,917	\$1,047,083	\$1,764,000

¹The cost of the G.E. cells is based on long-term manufacturing economics.

²Common equipment allocated by production.

TABLE 5.2

ON-SITE HYDROGEN PRODUCTION COSTS
(1979 \$'s)

Production	
MMSCF/Year - 95% on-stream	99.36
10^9 BTU/year ¹	32.3
Investment - M\$	1,764
Power (KW)	1,650
Operating Costs - Annual	
Power - (31 mills/KW hr.)	\$425,670
Make-up & Potable Water	1,500
Chems & Lubes - 1¢/CSCF & electrolyte	10,140
Labor - 1/2 man	13,000
Allocations & Site Overhead	11,520
G & A (20% on variable costs excluding power)	<u>5,150</u>
Sub-total	\$466,980
Fixed Costs	<u>432,330</u>
Total Costs	\$899,310
\$/CSCF	.905
\$/MMBTU	27.84

¹ 325 BTU/SCF HHV

TABLE 5.3
MERCHANT FACILITY INVESTMENT

	<u>G. E.</u>	<u>Elec.</u>	<u>Total</u>
Cells	\$ 259,000 ¹	\$ 284,000	\$ 543,000
Equipment ²	637,240	1,123,090	1,760,330
Spares	37,650	66,350	104,000
Operations	20,220	35,630	55,850
Construction	474,530	743,470	1,218,000
Engineering	84,580	149,060	233,640
Miscellaneous	37,930	66,860	104,790
Reserve - 10%	155,120	246,850	401,970
Builder's Risk Insurance	<u>3,410</u>	<u>5,430</u>	<u>8,840</u>
TOTAL	\$1,709,680	\$2,720,740	\$4,430,420

¹G.E. Long Term Projected Cost

²Common Equipment allocated by production

Appendix I contains a process flow sheet of the electrolytic facility which distinguishes between the equipment requirements of the on-site and merchant plant configurations. Figure 5.1 contains a plot plan for the merchant facility.

5.4 MERCHANT HYDROGEN PRODUCT COST

The estimated cost of merchant hydrogen would equal approximately \$1.62 per CSCF as calculated in Table 5.4. Power costs were calculated to equal \$467,980 or 29 per cent of the total costs. This amount has risen slightly over the on-site power cost, due to the additional compression and clean-up costs associated with hydrogen storage and purification. Annual fixed charges have risen dramatically to \$1,085,450 or 68 percent of the total, reflecting the higher investment and capital intensity of a merchant configuration.

The total cost of hydrogen per CSCF from the G.E. and Electrolyzer was \$1.68 and \$1.58, respectively including the power cost per CSCF of approximately \$.45 and \$.49. The lower energy cost associated with the G.E. cells reflects projected higher process efficiency and the higher pressure of the product stream, which requires less compression for storage.

5.5 MERCHANT FACILITY: PRODUCT COST, G.E. PROTOTYPE CELLS

The cost of hydrogen from the G.E. portion of the merchant facility was estimated in Table 5.5 using prototype cell costs. The cost of the prototype cells adds approximately \$840,000 to the capital costs and the fixed costs associated with the incremental investment brings the cost of the hydrogen to \$2.27 per CSCF vs. \$1.68 assuming long term projected cell costs.

Figure 5.1. Merchant Facility Plot Plan

TABLE 5.4

MERCHANT HYDROGEN PRODUCTION COSTS
(1979 \$'s)

	<u>GE Projected</u>	<u>Electrolyzer</u>	<u>Total</u>
Production -			
MMSCF/year - 95% onstream	35.664	63.696	99.360
10 ⁹ BTU/yr ¹	11.6	20.7	32.3
Investment - M\$ (1979)	1709.7	2720.7	4430.4
Power (KW) Cells and Auxiliaries	558	1,054	1,612
Other	61	141	202
Total	619	1,195	1,814
Operating Costs - annual			
Power - 31 mills/kwh	\$159,690	\$308,290	\$467,980
Make-up & Potable Water -			
\$1.50/1000 gal.	800	700	1,500
Chems & Lubes - 1¢/csf + electrolyte	3,570	6,570	10,140
Labor - 1/2 man	4,700	8,300	13,000
Allocations & Site OVH	8,960	14,300	23,260
G & A (20% on variable costs excluding power)	<u>1,900</u>	<u>3,250</u>	<u>5,150</u>
SUBTOTAL	179,620	341,410	521,030
Fixed Costs	<u>418,870</u>	<u>666,580</u>	<u>1,085,450</u>
Total Costs	\$598,490	\$1,007,990	\$1,606,480
\$/CSCF	1.68	1.58	1.62
\$/MMBTU ¹	51.86	48.55	49.74

¹ 325 BTU/SCF HHV

TABLE 5.5

MERCHANT HYDROGEN PRODUCTION COST
G. E. PROTOTYPE CELLS
(1979 \$'s)

Production - MMSCF/yr. - 95% onstream	35.66
10 ⁹ BTU/yr. ¹	11.6
Investment - M\$	2547.1
Power (KW)	619
Operating Costs - annual	
Power - 31 mills/KWH	\$159,690
Make-up & Potable Water	800
Chems & Lubes	3,570
Labor	4,700
Allocations & Site OVH	13,150
G & A (20% on variable costs excluding power)	<u>1,900</u>
Subtotal	\$183,810
Fixed Costs	<u>624,040</u>
Total	\$807,850
\$/100 SCF	2.27
\$/MMBTU	69.91

¹ 325 BTU/SCF HHV

5.6 SENSITIVITY ANALYSIS: HYDROGEN PRODUCTION COSTS

Numerous sensitivity analyses were performed on hydrogen production costs. The sensitivities were generally limited to the proposed facility configured as a merchant plant, since the on-site situation was not available.

5.6.1 SENSITIVITY TO CAPITAL INVESTMENT

Figure 5.2 presents hydrogen production cost as a function of investment. The level of investment and associated fixed charges significantly affect the cost of hydrogen. This graph can also apply to the on-site configuration, since the major difference between it and the merchant case is the amount of investment. Recall that in the base case, the only product cost difference, other than capital, between the on-site and merchant facilities, was annual power cost due to the higher compression and clean-up requirements associated with the merchant facility.

This sensitivity analysis could be used to make adjustments in the base case assumption of a "green field" development. The cost of hydrogen product associated with the installation of a facility on an improved site can be readily determined by adjusting the base case investment number as appropriate.

5.6.2 SENSITIVITY TO LABOR COST

The base case analysis assumed that the labor component for the merchant facility would be one half man/year, since the facility was designed to operate with limited attendance. For operational and safety reasons, it could be necessary to staff the facility on a

full time basis. Figure 5.3 indicates that the provision of one man twenty-four hours a day would add approximately \$.12/CSCF. In view of the relatively low sensitivity to labor and high sensitivity to capital investment, Air Products examined the substitution of less automated equipment and the use of additional manpower. The effects of the tradeoff were negligible and are not presented here.

5.6.3 SENSITIVITY TO ESCALATION

The effects on merchant hydrogen product cost from escalation through 1990 is shown in Figure 5.4. Three escalation scenarios were examined, differing only on the degree to which the variable cost of power would rise. Non-power costs were assumed to escalate at 8 percent annually. With respect to power, Curve A and B are based on annual utility power cost escalation at six and eight percent, respectively. Curve C assumes 3.3 percent annual power cost escalation, the projected escalation for hydropower.

5.6.4 SENSITIVITY TO POWER COST

The cost of merchant and on-site hydrogen as a function of power costs is presented in Figure 5.5. Focusing on power costs of 69 mills, as estimated in Case 2 of the hydropower base case, merchant and on-site hydrogen costs would equal \$2.20/CSCF and \$1.43/CSCF, respectively. Note, however, that this sensitivity is based on a 95% on-stream factor for the electrolytic plant and that it is improbable for low-head hydropower to be available so constantly. Figures 5.6 and 5.7 deal with the issue of supplementing hydropower based hydrogen production with liquid hydrogen or utility power.

Figure 5.2. Hydrogen Production Cost Sensitivity to Capital Investment

Figure 5.3. Hydrogen Production Cost Sensitivity to Operating Labor

Figure 5.4. Hydrogen Production Cost Sensitivity to Escalation

Figure 5.5. Hydrogen Production Cost Sensitivity to Power Cost

Figure 5.5 confirms graphically, the capital intensity of the on-site and particularly, the merchant hydrogen plant. At the Y intercept where the power costs are zero, the cost of hydrogen would equal approximately \$1.18/CSCF and \$.50/CSCF for the merchant and on-site cases, respectively.

5.6.5 FACILITY HYDROGEN COST WITH LIQUID HYDROGEN SUPPLEMENT

Figure 5.6 contains the results of an analysis, the purpose of which was to understand the cost affects of supplementing electrolytic hydrogen production with hauled-in liquid hydrogen. The two curves presented represent the weighted average cost of hydrogen from a merchant facility as a function of capacity utilization of the electrolytic cells with liquid hydrogen supplementing production for a total of approximately 100 MMSCF annually. Curve 1 assumes that the power can be purchased from the grid at a cost of 31 mills and the cost is completely variable. Curve 2 assumes a variable hydropower cost, which is a function of the capacity utilization of the hydroelectric generating equipment (Figure 3.2). The liquid hydrogen is costed at an average of \$.80/CSCF.

Curve 1 (31 mill power) indicates that lowest cost of hydrogen from the merchant facility would result from full utilization of the electrolytic cells without liquid supplement. The reason is that the incremental cost of producing hydrogen electrolytically is \$.44/CSCF, while the cost of liquid supplement, \$.80/CSCF, is incremental. Consequently, the unit cost of hydrogen falls to

its lowest level (\$1.62) upon fully utilizing the electrolytic plant. The terminal point of Curve 1 is \$1.62/CSCF of hydrogen as in the base case, which assumes the same 31 mill power cost and 95% utilization.

The shape of Curve 2 above 65 percent utilization can be similarly explained. The incremental cost of producing hydrogen electrolytically, even using the hydropower costs, is less than the incremental cost of the liquid supplement. Between 45 and 65 percent utilization, the incremental cost of liquid hydrogen supplement is lower than electrolytically produced hydrogen based on hydropower costs. There is an increasing reliance throughout this range on hydropowered based hydrogen which is more costly until 65 percent utilization is reached. Nevertheless, the average cost of hydrogen from the facility declines from 45 percent utilization to 65 percent due to power cost economics associated with higher hydropower utilization.

5.6.6 SUPPLEMENTAL LIQUID VERSUS SUPPLEMENTAL POWER COST COMPARISON

Figure 5.7 addresses the issue of whether to (1) supplement a hydropowered electrolytic production facility with utility power or (2) to supplement with liquid hydrogen to reach 99 MMSCF of annual hydrogen production depending on the amount of supplement required. The "Y" axis is the incremental cost of the supplement supply. The cross hatched area defines a range of probable liquid hydrogen costs as a function of supplement required. Curves 1-3 show the cost of grid power for various demand and energy ratios assuming 31 mill power. Curve 4 assumes 45 mill

power and a demand and energy components of 40 and 60 percent, respectively. Liquid hydrogen costs include both the fixed costs of storage, pumps, vaporizers, and the variable cost of liquid hydrogen delivered to the electrolytic facility.

Under Curve 1 power costs (31 mills, Demand/Energy = 15.85), the most cost effective supplement would be grid power regardless of the amount of supplement required. The power costs represented by the Curves 2, 3 and 4 offer cost equivalency which depends on the amount of supplement required. A typical hydropower facility would run at 48 percent, thus implying a supplemental need for approximately 6.2 MSCF/hr. Only power costs associated with Curve 4 are more expensive than liquid supplement at this level of supplement requirement. Therefore, under this scenario supplementing the hydro-powered hydrogen production should always take the form of grid power unless grid costs resemble 45 mills (Demand:Energy 40:60).

Figure 5.6. Merchant Facility Hydrogen Cost as Function Cell Utilization and Liquid Hydrogen Supplement

Figure 5.7. Supplemental Liquid versus Supplemental Power Cost Comparison

6.0 NEW ENGLAND HYDROGEN MARKET ANALYSIS

6.1 INTRODUCTION

The New England hydrogen market analysis focused on the two development options for the electrolytic hydrogen plant, an on-site and a merchant gas facility. Large volume users, whose requirements were large enough to justify the installation of a supply pipeline, were identified as prospects for on-site supply. Their locations were compared with a U.S. Army Corp of Engineers' list of small hydro-sites with a view toward finding a potential on-site supply situation. This option represented the greatest opportunity for cost competitiveness, since it minimized distribution costs. Probable cost competitiveness was a prerequisite to study continuation through Phase III, Site Engineering and Economics.

In addition to examining large users, the market analysis covered small and moderate size users who could be served from a merchant gas facility. Their locations were established to define customer concentrations and probable merchant plant locations which would minimize the distribution costs associated with tube trailer supply. Some geographical areas were eliminated from consideration as potential locations. Hydrogen use in New York, Rhode Island, Vermont, New Hampshire and Maine was too small and fragmented geographically. These characteristics seriously reduced the feasibility of these locations as a possible merchant plant site due to prohibitive distribution costs. Despite a large market, New Jersey was also eliminated as a potential site for the merchant facility since the

cost of hydrogen from existing sources is relatively inexpensive.

There are substantial quantities of by-product hydrogen in this region, and it can be delivered at a price against which merchant electrolytic hydrogen could not be competitive.

Connecticut and Massachusetts were the focus of the market investigation. Approximately 420 MMSCF of merchant hydrogen is consumed there annually with consumption largely concentrated in the Hartford and Boston areas. The majority of the hydrogen is supplied by three industrial gas companies, including Air Products and Chemicals, Inc., the Linde Division of Union Carbide, Inc., and Airco, Inc.

6.2 COMPETITIVE SOURCES OF MERCHANT HYDROGEN

The primary source of merchant hydrogen in Connecticut and Massachusetts is liquid hydrogen, either transported directly to the user or to redistribution centers. The liquid hydrogen is stored at the redistribution center, redistributed as liquid or transfilled as a gas for distribution to the smaller customers. Redistribution hydrogen sources are located in Acton, Massachusetts and Suffield, Connecticut. Liquid hydrogen shipped directly to the customer may come from as far away as New Orleans, reflecting the economics of liquid distribution. The cost of gaseous hydrogen at the redistribution centers is approximately \$.90/CSCF. Delivered (to the customer), prices range from \$.75/CSCF for a large liquid customer (without redistribution) to as high as \$3.00/CSCF for the smallest gaseous user.

6.3 THE ON-SITE OPTION

The on-site prospects which were examined (in light of proximity to hydro-sites) were typically larger liquid customers and hydrogen users who operate their own reformers.

The only possibility discovered during the on-site supply situation search was in Pawtucket, Rhode Island, where there was a dam site of sufficient generating capability to serve a nearby on-site prospect. Unfortunately, the owner of the dam, Blackstone Valley Electric, is considering recommissioning the site and it was not available for the program.

The on-site customer search in Paterson, NJ was also unsuccessful. The nearest prospect was too far from the Passaic River dam to justify pipeline supply. Furthermore, the City of Paterson was not receptive to Air Products proposed development.

6.4 THE MERCHANT OPTION

The proposed merchant facility would have served the smaller gaseous user market. Either Hartford or Boston would have been suitable locations for the merchant electrolytic facility, however, Hartford would have been preferable due to its more centralized location.

The electrolytic merchant facility would have had to be competitive with the cost of gas from the redistribution facility, which is approximately from \$.90 per CSCF (F.O.B. the plant). The estimated cost of hydrogen from the electrolytic merchant facility was \$1.62 (1979, 31 mill/KWH) and \$2.20 using a base case hydropower cost of 69 mills/KWH. The differential, even assuming power cost of 31 mills/KWH, was too large and the proposed facility, as a merchant plant, was judged commercially unviable.

7.0 HYDROGEN DISTRIBUTION COST ANALYSIS

7.1 PIPELINE DISTRIBUTION COSTS - ON-SITE

Figure 7.1 examines the cost of pipeline distribution as a function of pipeline length and volume of gas delivered. The investment was calculated at \$23 per installed foot. The annual costs are entirely fixed and were based on the use of a 24.5 percent capital charge rate (Table 5) applied to the total investment. Generally, this analysis indicates the greater importance of supply volume versus supply distance in locating the on-site situation. A prospect with a hydrogen requirement of 10 MSCF/hr. (base case 12 MSCF/hr.) could have been supplied via a 2 mile pipeline for less than \$.10/CSCF.

7.2 GASEOUS HYDROGEN DISTRIBUTION COSTS - MERCHANT

Table 7.1 and Figure 7.2 contain a cost analysis of bulk hydrogen distribution associated with a merchant facility serving customers between a 75 and 150 mile radius from the plant. An operational assumption of one delivery per trip was used for the sake of simplicity. A fuel cost of \$1.00 gallon was also assumed. The fixed cost includes fixed charges associated with distribution equipment investment allocated as a function of mileage.

The costs of bulk hydrogen distribution are clearly directly related to delivery distance ranging from approximately \$.40/CSCF for a customer 75 miles away to \$.61 for one 150 miles from the point of supply. The distribution cost would be added to the cost of the gas F.O.B. the plant, to arrive at the delivered cost to the customer.

Figure 7.1. Pipeline Distribution Cost Analysis

TABLE 7.1

DISTRIBUTION ANALYSIS -
GASEOUS HYDROGEN TUBE TRAILER SUPPLY
(1979 \$'s)

Distance	<u>150 RT Miles</u>	<u>300 RT Miles</u>
Volume - MMSCF/yr	99.36	99.36
Trips/yr ¹	994	994
Miles/yr	149,100	298,200
Operating Costs - \$/100 scf		
Maintenance - \$.20/mile	.030	.060
Distribution - Fixed - \$80/del.	.080	.080
Variable - \$.485/mile	<u>.073</u>	<u>.146</u>
Sub-Total	0.183	0.286
Fixed (all other) ²	<u>0.209</u>	<u>0.323</u>
TOTAL	0.392	0.609

¹100 MSCF/trip

²Includes 5% ROI, ITC @ 10%, tax rate @ 49.5% as basis

Figure 7.2. Distribution Analysis - Caseous Hydrogen
Tube Trailer Supply

8.0 STUDY CONCLUSIONS

In contrast to original perceptions on which this study was based, the cost of electrolytic hydrogen production for the capacity considered is capital intense; thus, the economic advantages associated with coupling low-head hydropower and electrolysis, on the presumptions that the power would be relatively inexpensive, were mitigated. The base case study analysis and actual site evaluations indicated that the cost of power from this source was likely to be more expensive than grid power through 1989 except under the most favorable comparative scenario.

Since the on-site situation was not available and the economics of the proposed merchant facility were uncompetitive, Air Products recommended discontinuation of the study. Consequently, Phase III, which would have involved a more detailed engineering and economic analysis of an actual site, was not undertaken.

APPENDIX 1
PROCESS DESCRIPTION AND FLOWSHEET

The turbines selected for use in developing hydropower for this project are Allis-Chalmers TUBE turbines. Ten standardized designs are available which reduce the usually high costs of custom engineering and manufacturing. The turbines incorporate a compact, horizontal, propeller-type design which provides the highest possible operating speed and maximum capacity for a given size. The compact design reduces the costs of excavation and civil construction. Major components of the TUBE turbine unit include an intake butterfly valve; the draft tube containing the turbine and through which the water flows; the vaned intake, and the runner with either fixed or adjustable blades; the shaft; the blade positioner; and the generator. Isolated operation requires a synchronous generator. Alternating power leaves the generator at 4160 volts in an amount equal to 94.5 percent of the power leaving the turbine. The size of the turbine and the amount of power generated are dependent mainly upon the flow rate and the availability of the water and on the available head. Power from the generator is recycled into direct current power and stepped down to lower voltages for use by the electrolytic cells.

The basic electrolytic plant consists of the rectifier, switchgear and voltage control equipment, the electrolytic cells, cell feed water purification equipment, electrolyte, a gas analyzer and other auxiliaries. The product hydrogen can then be compressed, purified and stored. Two types of electrolytic cells are to be used for this project.

The Stuart cell is of the uni-polar type, with each cell containing a number of single-polarity electrodes. Thirty-six cells are connected in series. The cell banks are fully automatic and may operate from 20% to 100% of full capacity. Individual cells may be disconnected independently. Hydrogen of 99.5% purity is produced at a rate directly proportional to the operating current. The correct level of electrolyte (KOH) is automatically maintained through individual feed water valves. The hydrogen gas leaves the electrolyzer at 100°F and atmospheric pressure.

General Electric's Solid Polymer Electrolyte (SPE) cells contain a solid polymer electrolyte which has ion exchange characteristics which make it highly conductive to hydrogen ion. No liquid electrolyte is required; the only liquid used anywhere in the system is demineralized water. Advantages of the SPE system include cell efficiency higher than conventional electrolyzers, an absence of free corrosive liquids, and improved reliability and safety. Two modules of 60 cells each connected in parallel are required. Fifty percent loss of production occurs when each module is taken off-line. Hydrogen leaves the electrolyzer unit at 300 psig and 110°F.

All feed water is supplied to both banks of cells from a shared demineralizer and storage tank. Oxygen produced by the cells is vented to the atmosphere.

From the cells, the product gas travels to the hydrogen compressor where it is compressed to 3130 psia. The compressor is a four stage, two throw, balanced opposed, oil lubricated model complete with a 200 HP motor, intercoolers, aftercooler, and side stream connections at the third and fourth stage inlets.

The possibility of employing a water-lubricated compressor was also investigated. It was found, however, that despite the additional cost of an oil-lubricated compressor is more cost effective.

From the compressor, the high-pressure gas is piped to a drier skid which contains a catalytic purifier, coolers, separators, and driers. The catalytic purifier, or NIXOX unit, removes the oxygen impurity from the hydrogen gas. Water is then removed. Hydrogen leaving the skid is now of bulk hydrogen industrial quality. From this stream, a portion of the gas is piped back through the drier, regenerating it, before it is returned to the compressor.

The purified hydrogen is then piped to the storage area where it is either stored in high-pressure bottles with a total capacity of 489,000 scf at 3100 psia, fed directly to an on-site customer, or loaded onto tube trailers for distribution. In the event of production stoppages, a 20,000 gallon liquid hydrogen storage tank is provided. Supplemental liquid hydrogen may be trucked in from an Air Products distribution center, stored in the tank, and then pumped and vaporized into the storage bottles as needed. In this way, a constant supply of hydrogen to the customer is assured. Boil-off from the liquid hydrogen tank is returned to the hydrogen compressor.

Other equipment includes a liquid nitrogen storage tank and vaporizer for purging requirements; and a cooling water system for the cells, compressor, and coolers.