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## Hydrogen from Renewable Energy: Photovoltaic/Water Electrolysis as an Exemplary Approach

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HYDROGEN FROM RENEWABLE ENERGY: PHOTOVOLTAIC/WATER  
ELECTROLYSIS AS AN EXEMPLARY APPROACH

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ABSTRACT

Potential large-scale production of liquid hydrogen and liquid oxygen from water using photovoltaic solar energy conversion at the NASA Kennedy Space Center is examined in this paper. The example non-optimized, stand-alone facility described produces about 5.76 million pounds of liquid hydrogen per year, and 8 times that much liquid oxygen, which could support about 18 Space Shuttle launches per year.

A 100-MWp flat-plate photovoltaic array, measuring 1.65 square miles, is required. The full array is made up of 249 modular 400-kWp arrays with several electrical/gas product "grids" considered. Hydrogen and oxygen are produced with either dispersed or central water electrolyzers. A central product liquefaction facility with 2-weeks' storage is provided.

Estimated liquid hydrogen product costs, levelized over a 20-year facility life, range from about \$3.00 to \$7.50/lb liquid hydrogen, depending mainly on the cost of installed photovoltaics. (The range examined was \$.50 to \$2/Wp.) At about \$1.50/Wp, a liquid hydrogen conventional/non-fossil cost parity would seem to be achievable over the period 1990 to 2010.

Keywords: liquid hydrogen, liquid oxygen, solar energy, photovoltaics, water electrolyzers, liquefiers, Space Shuttle propellants.

SUMMARY

This paper addresses the large-scale, stand-alone production of liquid hydrogen and oxygen via water electrolysis powered by electricity from a photovoltaic array located on or near the NASA-Kennedy Space Center (KSC). Liquefaction of product gases is accomplished by a conventional plant powered by a dedicated photovoltaic array with battery storage.

The system was sized to produce on the order of 6 million lb/year of liquid hydrogen ( $5.76 \times 10^6$ ), and  $46 \times 10^6$  pounds/year of liquid oxygen are produced as well. For perspective, this equates to full liquid hydrogen/liquid oxygen logistics support for the Space Shuttle Program operating at about 18 launches per year.

A total photovoltaic array power rating of about 100 MWp is required based on recorded insolation received at KSC. The resulting array power split is 67.6 MWp for water electrolyzer facility operation and 32 MWp for the hydrogen and oxygen liquefier operation. Hydrogen and oxygen production from water occurs only when the photovoltaic array is active under direct and diffuse illumination by the sun. However, product liquefaction proceeds around the clock with nighttime energy supplied from battery storage charged photovoltaically during the day.

Using estimated capital costs and operating and maintenance expenses, levelized costs are calculated for liquid hydrogen and liquid oxygen produced over the 20-year facility life. Costing is based on standardized guidelines for electric utility facilities by the Electric Power Research Institute (EPRI).

BACKGROUND

At present, KSC's liquid hydrogen demands are met by conventional industrial gas supply means quite similar to other merchant hydrogen customers. Specifically, liquid hydrogen is purchased under contract from Air Products & Chemicals, Inc. The hydrogen is produced by the conventional natural gas (methane) steam reforming process and liquefied at Air Products' New Orleans facility. From there, it is transported by KSC-owned-and-operated 13,000-gallon tractor-trailer units. Recently, trial runs have begun on rail tank car delivery as a way of supplementing over-the-road delivery.

Natural gas, the basic feedstock, is a depletable fossil fuel resource subject to near-term cost escalations and unavailability. Accordingly, NASA planners have initiated studies of alternative sources of liquid hydrogen by way of opening up possible options for ensuring long-term continuation of supplies. The continued use of natural gas will, of course, be a competitive option.

Another approach under consideration at KSC is on-site coal gasification in a "Polygeneration" facility, i.e., one providing several useful products in addition to hydrogen. Yet another category of options is non-fossil production of liquid hydrogen. Based on a competitive procurement, KSC awarded a contract to a study team led by E:F Technology, Inc., in late-September 1982 (Ref. 1). To address this possibility, this paper was developed from information gathered/analyzed for this contract (see Acknowledgments).

This paper addresses one of the nearer-term, KSC-sited, solar energy-operated alternatives: a photovoltaic-based (solar cell)/water electrolysis, liquid hydrogen/liquid oxygen production system. This system was identified earlier by E:F as one of four solar/hydrogen production approaches which were commercializable by the year 2000 (Ref. 2). As next discussed, the example system to be described is not optimized nor is it necessarily related to those one or two systems called out to be studied in some depth by the contractor team.

The basic objective of this presentation is to illustrate one specific approach for providing non-fossil-produced liquid hydrogen and oxygen as an alternative to today's fossil-based production means. Being illustrative and not reflecting trade-offs and "fine tuning" advantages, this exemplary system demonstrates basic feasibility while suggesting the order of product costs which may be expected, in a generic sense, from solar-based hydrogen production.

#### SYSTEM REQUIREMENTS

The following basic guidelines were adopted in configuring the exemplary system:

- Photovoltaic solar energy conversion to be used on a stand-alone basis (no utility power or other energy inputs)
- KSC facility location (insolation data used is that measured by the Florida Solar Energy Center at Cape Canaveral)
- Technology and estimated costs applicable to the 1987-1992 time period
- Nominally, the Space Shuttle's 18 launches/year to be fully supported; this

equates to a nominal 6 million lb/year of liquid hydrogen use (final facility sizing:  $5.76 \times 10^6$  lb/yr)

- Coproduct oxygen also to be collected and liquefied (leading to some excess liquid oxygen over Shuttle needs as met by the liquid hydrogen produced).

#### TECHNICAL APPROACH

The basic makeup of the exemplary system is shown in block diagram form in Figure 1. Displayed here are subsystems operating in a series flow-through manner. These are:

- Photovoltaic Array--provides direct conversion of received sunlight, both direct and diffused, into d-c electricity
- Water Electrolyzer--provides electrochemical separation of the constituents of water using photovoltaic electricity into molecular hydrogen and oxygen as ambient temperature gases
- Product Liquefiers--converts the ambient-temperature gaseous electrolyzer products into cryogenic liquid hydrogen and oxygen, as used in the Space Shuttle.

Associated with these subsystems, various kinds of energy and product storage are provided, e.g., batteries and gaseous and liquid storage.

#### SYSTEM SIZING AND LAYOUT

In order to produce six million pounds of hydrogen gas per year, 294.3-MW hours/day of energy must be stored in the form of hydrogen. Using sunlight at 5 to 6 hours/day of full-sun equivalent implies that a system of 50- to 60-MW peak power (without considering losses in the process) is required.

To date, no photovoltaic system of this size has been constructed, although at least one is planned--with the initial few Megawatts of capacity under construction (Ref. 3). Including the liquefier facility, the system discussed here will occupy approximately 1.5 square miles. Again for perspective, space availability at a facility such as KSC should not be a problem.

Typically, the output of existing and planned PV installations has been a-c electricity. With hydrogen as the product, several unconventional system approaches are possible, each having its own set of advantages/disadvantages. Those approaches covered in this paper rely on a basic building block: a 400-kWp PV sub-array or module (to be described later). The method of linking the required 170 or so modules leads to several possibilities to be further discussed:

- PV module + inverter + a-c grid + central rectifier + central electrolyzer + gaseous product storage
- PV module + d-c busbar + central electrolyzer + gaseous product storage
- PV module + distributed electrolyzer gas mains + gaseous product storage.

The liquefier itself will be powered by the first option using its own "dedicated" array. Distributed battery storage provides 24 hour/day operation (liquefiers only).

#### THE 400-kWp PV MODULE

Following more or less conventional practice, PV panels which are 3.125 meters high are arranged in rows 10 meters apart as shown in Figure 2. The panels are mounted on a horizontal "torque tube" permitting rotation along an east-west axis. Throughout the year, the tilt angle of the panels is changed several times to keep the insolation nearly normal to the panel surface at solar noon. An example of such a tilt schedule is given in Table 1. Using values from this table (used at Florida Solar Energy Center, FSEC, 28.5°N Latitude), at winter solstice, the 10-meter spacing together with a scheduled 48° tilt angle results in some shading of panels at sun altitudes less than 16°. Unshaded operation is then possible from 8:30 a.m. to 3:30 p.m. At the 24° tilt angle associated with the equinoxes (mid-March, mid-September), no shading occurs since at sun altitudes less than 10° (which the panels would block), the sun is behind the south-facing collectors. No shading occurs when the sun is further north (e.g., Summer).

Table 1. TILT ANGLE AND APPLICABLE DATES

Tilt in Degrees	Date Range
48	3 Nov - 9 Feb
40	10 Feb - 4 Mar
32	5 Mar - 24 Mar
24	25 Mar - 13 Apr
16	14 Apr - 7 May
8	8 May - 7 Aug
16	8 Aug - 30 Aug
24	31 Aug - 20 Sep
32	21 Sep - 10 Oct
40	11 Oct - 2 Nov

In order to determine the optimum dimensions for the 400-kWp module, i.e., the number of rows and the corresponding row length, we assume rectangular arrays were laid out with the d-c power tie-point at the rough geometric center of the rectangle. The cost of copper conductors was to be minimized. The number of rows was varied from 1 (1,600 m long) to 160 (10 m long) each. The PV panels

were taken to be 8% efficient on a panel area basis--a number which combines cell efficiency and geometric packing fraction.

Copper requirements were calculated for each configuration so that there exists at most a 1-V drop from each 500-V submodule of the 400-kWp sub-array to the power-tie point. Copper costs per peak watt were calculated using cable and wire at \$4/pound installed. The results are shown in Figure 3. It can be seen that a clear minimum exists at 13 rows of collectors, implying 123 m long rows.

Collection at 500-V was arrived at after considering worker safety, good inverter efficiencies (if used), and electrolyzer matching without dependence on d-c to d-c converters. Higher voltages would reduce the copper requirement but would detract from PV-electrolyzer matching. (See next section.) PV cell operating experience at 1,000 V and higher has resulted in arcing from the cell through the potting materials to ground. It is noted that the most recent Block V photovoltaics government buy specifies 1,000-V operation. Lower collection voltage (than 500-V) would lead to excessive copper cabling as well as lower a-c inverter efficiencies.

Thus, as shown in Figure 4, the 400-kWp sub-array module is physically 123 x 130 m in extent and provides d-c at 499 V and 800 A. The 499 V reflects a power loss of 800 W out of the total produced--an 0.2% loss.

Based on available PV cost predictions, e.g., Reference 4, we are using installed costs from \$.50 to \$2.00 per peak watt as spanning the range of costs generally anticipated by 1988. These costs, as used here, reflect only the PV panels, their mounting, and connecting copper cabling as described above. Power conditioning, storage, etc., are otherwise covered as discussed in a later section dealing with combining these modules into the overall system. The installed module cost then is \$200,000 to \$800,000 for the 400-kWp module excluding land costs.

#### THE ELECTROLYZER MODULE

Today's electrolysis plants are predicated on power from an a-c grid which is rectified and then fed to the electrolyzers through an active power controller which feeds the units optimally. As a consequence, electrolyzer optimization has tended toward larger cell areas and lower voltage and higher current than those considered here (i.e., 200-V, 1,000-A units in series as opposed to 500-V, 800-A). For this study, it is assumed that a block purchase of 60- to 100-MW of electrolyzer will permit production-basis construction of units meeting the needs of the facility.

When consideration is given to using electrolyzers in conjunction with a PV array as the electricity source, the usual design approach encompasses d-c to d-c power conditioning systems to "track" the peak power point of the PV array while meeting the current/voltage polarization curve requirements of the electrolyzer and also adjusting to varying insolation levels throughout the day. Such conditioning systems can result in the loss of 5% to 10% of the power ahead of the electrolyzer.

Based on studies at E:F (Ref. 5) and elsewhere (e.g., Ref. 6), it is possible, however, to achieve good matching of the PV power source to the electrolyzer without the use of an active control system. This matching simply requires that the PV array and electrolyzer be specially designed so that the locus of the peak power points of the array, as insolation varies, approximates the voltage-current characteristics (polarization curve) of the electrolyzer.

An example of such a match for a 400-kWp module is shown in Figure 5. Also indicated in the figure are the boundaries in which the polarization curve must remain to keep mismatch losses below 5%. The PV-electrolyzer match will remain good over a wide range of operating conditions since thermal effects (i.e., operating temperatures) cause the locus of peak power points and the polarization curve to shift in the same general direction (to the left for higher temperatures; to the right for lower temperatures). The most severe mismatch likely to occur in a well-designed system will result from component aging and PV cell failures. As the electrolyzer ages, its polarization curve will shift to the right, while a deteriorating PV array will have the locus of peak power points shifted to the left in Figure 5. When, after several years, the mismatch becomes large, maintenance on both the array and the electrolyzer is mandated to restore efficient operation.

The direct coupling of an electrolyzer to a PV array is not a new idea (Refs. 7 and 8); however, directly coupled, well-matched systems have not yet been demonstrated. To this end, FSEC is currently implementing such a demonstration using a 2-kW electrolyzer specially built by Teledyne to E:F's specifications.

It is possible to design the electrolyzer so that at insolation levels above  $125\text{-W/m}^2$ , there is sufficient cell voltage for electrolysis to proceed. Below this level, the electrolyzer ceases functioning. In order to quantify potential losses due to periods of low insolation, solar data for calendar year 1981 (obtained from FSEC) has been examined. Of the annual tilted surface global insola-

tion measured, 97.8% was above the  $125\text{-W/m}^2$  threshold. In this analysis, the 15-minute data points as measured were combined into hourly values so that the 2.2% loss of available insolation probably represents an upper limit to the fraction of radiation which is unusable by a directly-connected electrolyzer of the type described.

It is expected that losses from the mismatch shown in Figure 5 will not exceed 2%. The additional loss of 2% unusable insolation results in a net 4% loss in matching. Note that this is better than that obtainable by using active power trackers and that this level should be achievable at no additional cost in contrast to the power-tracker situation.

Available electrolyzers in the 400-kW range are approximately 80% efficient (Ref. 9), i.e., it takes  $1.25\text{-kWhr}$  of electricity to produce 1-kWhr of chemical energy in the hydrogen produced (higher heating value). These units, with no power conditioning, should cost approximately \$200/kW. The electrolyzers require double-deionized feedwater for satisfactory operation. Such a water conditioning plant for a 100-MW plant costs approximately \$100,000 (Ref. 10).

#### INTEGRATION OF 400-kWp PV MODULES

The full PV array ("super grid") size, using the stated 80% efficient electrolyzers and considering the usable average tilted surface global insolation measured by FSEC (1977-1982), turns out to be 67.5 MWp. Thus, 169 of the 400-kWp PV modules discussed previously are integrated into a "super grid" comprising the overall hydrogen-oxygen production system. The super grid is shown in Figure 6, and is  $1.69 \times 1.60$  km in extent. This corresponds to 9.9 acres/MW, comparing favorably with the 9 acres/MW described for the SMUD array (Ref. 2). At \$.50 to \$2 per peak watt installed, such an array would cost \$33.8 to \$135.2 million not including the electrolyzers.

Three options for linking the array into a hydrogen-producing system are presented next. It will be recalled that these are: (1) a-c grid, (2) d-c grid, and (3) gaseous products grid (dispersed electrolyzers). For all the options investigated, the interconnections followed the routing shown in Figure 6, with a main trunk 1.69-km long with 26 branches of 0.8-km each. This provides optimal grid conditions for all three options considered.

Of the three options cited, the first two allow for the possible reclamation of the rejected low-temperature heat from a central electrolyzer facility. The heat is a direct result of electrolyzer inefficiency (20%) and amounts to about 250 million Btu/day at about 200°F. For perspective, this heat source is

equivalent to a large flat-plate solar thermal array which is intrinsic to the central electrolyzer approach. In each case, central water purification is accomplished starting with municipal potable water. Water costs turn out to be negligible. For the dispersed electrolyzer configuration only, a pump with 55-gpm capacity to feed water to the dispersed electrolyzers is assumed in each at 50 psi head to compensate for pipe friction.

Each of the three grid configuration options is discussed next.

#### (1) Distributed Inverters and an a-c Network

This design approach equates to that used when feeding a conventional utility a-c grid with power from the PV modules. An inverter-transformer is placed at the power-tie point of each 400-kWp PV module which then feeds a 35-kV a-c grid. At the central electrolyzer facility (on the north side of the overall array), the power is fed to a transformer-rectifier and power conditioning unit before being bused to the electrolyzers. Losses are taken as 5% in the inverters and 4% in the power conditioning for a 91% system throughput to the electrolyzer cells.

The principal advantage of this scheme is the use of existing technology and available components from inverter through product gas collection. Another advantage is that early-a.m. and late-p.m. low levels of insolation can be used to drive an appropriate subset of the electrolyzer units maintaining optimal current and voltage control.

Costs for the a-c lines were taken as \$10/foot installed, which, for the 13 miles of line, is approximately \$700,000. The inverters were taken as \$50/kW for a total of \$3.4 million. Power conditioning at the central electrolyzer plant at \$20/kW amounts to \$1.3 million. The electrolyzers themselves, at \$200/kW, amount to \$12.3 million and are housed in a \$200,000 building.

#### (2) d-c Busbar Integration and Central Electrolysis

In this option, the 169 PV modules are tied by copper busbars carrying 500-V d-c power along the branches to the main trunk. Copper cabling costs were taken at \$4/lb installed.

The grid pattern shown in Figure 6 resulted in the use of 223.5 metric tons of copper being installed at a cost of \$2 million. Resulting ohmic losses in this design were 4.3-MW at peak insolation--6.4% of total power. At less than peak power conditions, the losses are less. The overall ohmic loss is estimated at 5% throughout the day. Doubling the amount of copper would result in roughly halving peak ohmic losses.

An alternative design with 13 d-c busbars running north and south and tied to a collector bus on the north edge of the full array was also considered. This resulted in 376.5 metric tons of copper installed at a cost of \$3.3 million and a peak ohmic loss of 3.64 MW.

A comparison of the two designs indicates a trade-off between \$1.3 million in copper and .65 MW of array (assumed to make up for the losses). At installed PV costs of less than \$2/W (peak), this represents a cost penalty; at \$2/W (peak), there is a breakeven situation.

Total costs for this option as used in the following analysis are \$12.8 million for electrolyzers housed in a \$200,000 building; \$2 million for the copper busbars installed into the grid pattern. Losses in the d-c busbar case are 5% in ohmic losses in the copper, and the 4% in threshold insolation and tracking mismatch mentioned in the electrolyzer discussion above, for a total system energy throughput efficiency of 91%.

#### (3) Distributed Electrolyzer Network

In this option, a 400-kW electrolyzer matched to the 400-kWp PV array is installed at the power-tie point within each basic module and the hydrogen and oxygen produced are fed through a low-pressure gas distribution pipeline to a central collection point. Water is piped to each electrolyzer from a central purifier facility.

The water and product gas mains are laid in a common trench following the trunk and branch pattern of Figure 6. Pipe and main sizing and costs were calculated from Ref. 11 and were updated to 1982 dollars using a 7%/year inflation rate. Gas pressures were taken to be 70 psi at the electrolyzers and 10 psi at the central collection point. The water supply system to feed the water pipe is rated at 54.3 gpm.

Costs for this design are \$13.52 million for the electrolyzers and \$1 million for the three pipe grids (of properly varying diameter) as installed in the common trench. Losses in this design are only the 4% resulting from less than threshold insolation and non-optimized tracking between the PV array and the electrolyzer.

#### CAPITAL COST COMPARISON OF THE THREE OPTIONS

Table 2 recaps the costs associated with constructing the three options considered for tying the system modules into an overall system which can provide hydrogen and oxygen to the liquefier facility. Elements of the overall system common to all three options (PV array, water conditioning, and gaseous

storage) have been omitted in order to focus on interconnection costs alone. Using as a crude screening index the capital cost of the interconnect divided by yearly hydrogen capacity, we find that the most obvious candidate--distributed inverters--is the worst choice of the three options considered.

The central electrolyzer options, which allow electrolyzer-rejected heat recovery, have the potential of reducing hydrogen costs by \$.10/lb if 70% of the waste heat could be reclaimed at no capital cost. The comparison is based on fuel oil at \$8/10<sup>6</sup> Btu. Because of additional piping costs and, more significantly, heat loss in a hot water collection grid, the distributed electrolyzer option does not appear capable of heat reclamation. Note that the capital cost per yearly pound of hydrogen produced is a screening calculation only: The actual levelized cost over a 20-year period is derived in the last section of this paper. What can be deduced from the screening calculation presented herein is only the ranking of the three options.

Table 2. CAPITAL COSTS (in 10<sup>6</sup>\$) FOR THREE INTERCONNECTION OPTIONS

Options	(1)	(2)	(3)
Inverters	3.4	--	--
a-c Grid	.7	--	--
Power Cond.	1.3	--	--
d-c Bus	--	2.0	--
Gas/Water Mains	--	--	1.0
Electrolyzers	12.5	12.8	13.5
TOTAL	17.9	14.8	14.5
System Losses	9%	9%	4%
GH <sub>2</sub> Production (lbs/year)	5.46	5.46	5.76
Specific Capital Cost (\$/lb H <sub>2</sub> /year)	3.28	2.71	2.52

Based on these results, the distributed electrolyzer approach is tentatively seen to be the best choice, having 7.5% lower specific capital costs than the all-d-c/central electrolyzer option and 30% below the distributed inverter option. However, if electrolyzer rejected heat coproduct value is substantial, the choice might be the all-d-c/central electrolyzer option.

#### REMAINDER OF THE SYSTEM

Liquid hydrogen is often the required form from the using system viewpoint (e.g., Space Shuttle). Also, large-scale delivery of hydrogen over distances of, say, 100 miles requires the liquid form (unless a gas pipeline is available). In order to render the hydro-

gen and oxygen into a truly usable form in such a large-scale facility, a liquefaction capability is included in the system.

To provide continuous operation of the liquefier, the system provides for one-day of gas storage. Two weeks of storage for the liquefied gases are also included. The liquefier chosen is an 8 ton/day hydrogen unit (5.84 X 10<sup>6</sup> lbs/year), with a corresponding liquefaction capacity for 63.5 tons/day oxygen. Capital costs for this plant are \$14.6 million and the electrical input required is 5.48 MW for 24 hours/day (Ref. 12).

To support such a plant wholly on renewable energy, 32-MWp of PV array is required (80 modules at 400-kWp each). This would be configured in the distributed inverter mode described earlier since the conventional liquefaction facility requires a-c power (d-c power might be used, but this option was not examined). This array size provides 8-hour operation of the plant directly, while charging 87.7-MWhr of battery storage to operate the liquefier during the other 16 hours of operation per day. It is important to operate the liquefier around-the-clock for both cost minimization and operating reasons, as next discussed.

Consideration was given to different size liquefiers and amounts of battery storage. Basically, this is a case of the trade-off between liquefier facility, photovoltaic array, and battery costs. At the extreme of no storage and operation on the PV array only, a 35 ton/day hydrogen unit would be required. Various intermediate sizes with some battery storage were also considered. The continuous operation of the liquefier plant selected was cheaper by \$8 to \$20 million than the no-storage alternative, and was essentially the same cost as the larger units which run at part capacity through the non-sun part of the day to reduce battery storage costs.

In the dedicated liquefier array, a 68.5-kW inverter capacity and 1.1-MWhr of battery storage are placed at each 400-kWp module. During the day when the PV module output exceeds 68.5 kW, the extra power is directed to storage. The placement of storage at the PV module allows the same inverter to be used for processing both the PV and battery outputs. The alternative is to use larger inverters and place battery storage at the liquefier plant--invoking rectification and increased inverter costs. This costs \$1.6 million more than the configuration presented here.

Costs for the liquefier subsystem then are \$14.6 million for the hydrogen and oxygen liquefier complex, \$16 to \$64 million for the dedicated PV array to power the liquefier, \$270,000 for inverters, \$330,000 for the a-c

grid, and \$8.77 million for the batteries (at \$100/kWhr). One day's gas storage for two gases is estimated at \$4.6 million using in-production LPG-type containers. Two weeks' storage for liquid oxygen costs \$400,000; for liquid hydrogen, the cost is \$1.6 million. Conventional spherical, vacuum-jacketed, field-constructed vessels of 217,000 and 400,000 gallons, respectively, are needed.

Figure 7 shows the overall facility physical layout as dominated by the two PV arrays. It is 1.65 square miles in area.

SUMMARY OF CAPITAL AND OPERATING & MAINTENANCE COST ESTIMATES

The combined costs for the entire system, including final liquid storage, are presented in Table 3. The range of costs shown represents the effects of considering installed PV module costs of from \$.50 to \$2 per peak watt.

Table 3. COST SUMMARY (MILLIONS OF DOLLARS)

	Capital	O&M
PV for Electrolyzer	33.8-135.2	--
PV for Liquefier	16 - 64	--
TOTAL PV	49.8-199.2	1.8-3.4
Liquefier	14.6	.75
Gas Storage	4.6	.46
Liquid Storage	2.0	.20
Interconnections & Electrolyzer	14.5	.29
Inverters, Grid & Batteries	9.4	.56
TOTALS	94.9-244.3	4.06-5.66 (4.3%-2.3%)

Operating and maintenance (O&M) costs were taken from Ref. 12 for the liquefier. The storage facility O&M costs were taken as 1% of purchase costs per year. The electrolyzer O&M cost was taken as 2%. The O&M costs for the power supply for the liquefier plant include the replacement of 5% of the batteries per year over the life of the system.

For the PV array, it is assumed that 3 kW of array is replaced each day to account for field failures. A crew of 50 individuals working a one-shift, 5-day week is included to perform inspections, do maintenance, and adjust the tilt of the arrays 10 times per year.

In review, photovoltaic array installed costs are dominant, being 53% to 82% of the required investment at \$.50/Wp and \$2/Wp, respectively. O&M costs related to the PV arrays are also prominent at 44% and 60%, respectively. The electrolyzer and the hydrogen/oxygen liquefier represent equal capital

costs at 15% and 6% of the total, respectively, for the two PV installed costs.

One-day product gas storage costs more than double 2-weeks' of liquid storage, but together are less than half the liquefier or electrolyzer costs. Actually, combined storage costs are only about two-thirds that of the sum of the inverter, electric or gas grid, and battery costs.

FINAL PRODUCT LEVELIZED COST

These capital costs and O&M expenses were evaluated by means of the Electric Power Research Institute's (EPRI) TAG model (Ref. 13) assuming 6% inflation and a 12% discount rate. Income taxes were taken as 48%; and property taxes and insurance at 2%. A 10% investment tax credit was taken and all equipment was depreciated over 10 years with a 20-year facility book life.

Under these assumptions, the levelized product cost for one pound of liquid hydrogen and the stoichiometrically-equivalent of 11-liquid oxygen (8 lbs) is presented in Table 4.

In order to arrive at a liquid hydrogen cost alone, the cost of the oxygen must be subtracted from the above numbers. Using today's values (Ref. 12), with a 6% inflation rate, and a 3% escalation over inflation rate to reflect increasing electrical costs, the 20-year levelized cost of liquid oxygen corresponding to one pound of hydrogen is \$.60, i.e., \$.075/lb of liquid oxygen. Liquid hydrogen costs per pound, then, are \$.738, \$.405, and \$.301 for installed photovoltaic array costs of \$2, \$1, and \$.50, respectively, per peak watt.

Table 4. LEVELIZED HYDROGEN AND OXYGEN COSTS

PV Installed Costs (\$/Wp)	Product Costs (\$)	
	1 lb LH <sub>2</sub> + 8 lb LO <sub>2</sub>	1 lb LH <sub>2</sub>
.50	3.61	3.01
1.00	4.65	4.05
2.00	7.98	7.38

DISCUSSION

Current delivered KSC costs are about \$2.72 lb for liquid hydrogen (Ref. 14) and about \$.045/lb for liquid oxygen (Ref. 15). As noted earlier, the hydrogen plant operating costs are tied to the price of natural gas, while oxygen plant operating costs are tied to electricity prices (to operate large air compressors mainly).

By initial comparison, the non-fossil product costs presented here (Table 4) appear non-competitive. However, recall that these



are leveled costs for a 20-year period, beginning no earlier than 1987. If conventionally-produced hydrogen and oxygen are compared on the same basis, with appropriate escalation-above-inflation of natural gas (or any fossil feedstock) and electricity, the non-fossil production falls into the competitive range. Using the same 6% inflation and 3% escalation rates as were used earlier for liquid oxygen, the 20-year leveled cost for liquid hydrogen becomes \$5.63/lb—within the range of the costs presented for PV. If the photovoltaic installed costs were to be about \$1.50/Wp, cost parity between conventionally-produced and the subject facility-produced liquid hydrogen could be achievable.

By 1990, installed PV arrays without power conditioning costing \$2/Wp seem likely (Ref. 4). It is possible that, using such technologies as amorphous thin-film cells and innovative balance-of-system design, costs could be even lower, although the \$.50/Wp number used as the low end of the cost range in this paper may not, in fact, be attainable.

One possible means of reducing costs would be consideration of fully-tracking PV arrays, which would produce approximately 20% more energy per year than the essentially fixed, manually tilted arrays considered here. O&M costs would be correspondingly reduced. The tracking would not have to be anywhere near as precise as that for a power tower, for which operating examples exist. Several PV projects have been recently announced which provide this full-tracking capability. However, it should be noted that as installed PV panel costs are brought down, the system cost-fraction required for full-tracking goes up proportionately.

We have not addressed the automatic monitoring of the performance of the 400-kWp modules, or the submodules which constitute the module. It is possible that the use of microcomputer chips with A-D converters could be installed to provide the monitoring, but associated costs have not been estimated and the size of the smallest element to be monitored has not been determined. This may be another avenue for decreasing O&M costs.

As should be clearly evident in the foregoing presentation, the facility described is entirely stand-alone, requiring only solar energy and water and no other input energy, e.g., utility power, fuel. Alternatively, there appears to be a number of powerful incentives for introducing electric utility grid interfacing to the benefit of resulting product costs. For example, operating the liquefier on utility power during non-sun periods would reduce the associated PV array size and costs, and eliminate the need for batteries. From the utility point of view, this might equate generally to an off-peak,

night-time load, providing for favorable rates.

Going the other way, mid-day PV power might be supplied in some fractional part to the utility during peak-load periods at favorable purchase rates by the utility. Electrolyzer input could be correspondingly reduced at those times which would act to raise the efficiency of the electrolysis process. It may even be the case that the utility might take some of the hydrogen and oxygen products for its own use at a price (e.g., for peaking power). Such prospective facility "cooperative grid interaction," though of high interest and to be initially explored in the present KSC study contract, remains beyond the scope of this paper.

#### CONCLUDING REMARKS

As an exemplary non-fossil liquid hydrogen/liquid oxygen production approach, the 1.65 square mile, 100-MWp facility laid out (but not optimized) here could provide competitively-priced product for the 2-decade period beginning around 1987-1992. Product costs remain highly sensitive to installed photovoltaic costs assumed since these dominate the total facility capital costs (the range of 50% to 85%).

Further study of the PV approach should be made, in perspective with alternative non-fossil hydrogen production approaches, to deepen this inquiry (sensitivity studies, innovative designs, etc.). Such variants as full-tracking arrays and electric utility interfacing should be included. Realistic projections for conventional (and unconventional) fossil-based production costs for the same period should obviously be developed as a basis for comparison and future decision-making.

It would appear from this and other contemporary assessments, that energy planners within NASA and elsewhere can begin to look seriously at this one avenue and others supportive of the long-term transition to a sustainable, non-fossil energy system.

#### ACKNOWLEDGMENTS

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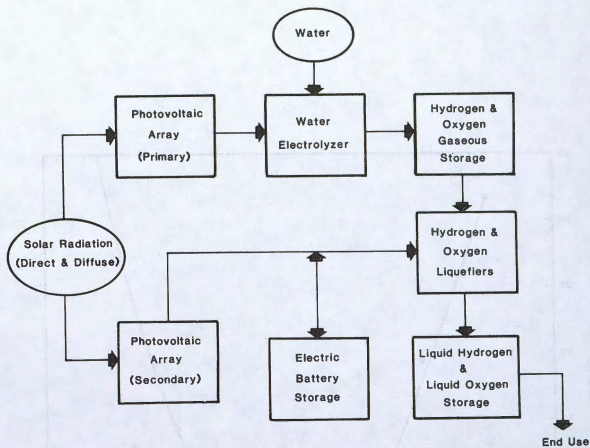


Figure 1. OVERALL SYSTEM FUNCTIONAL DIAGRAM

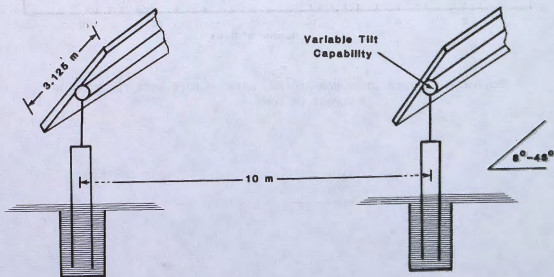


Figure 2. GEOMETRY OF TILTABLE, SOUTH-FACING PHOTOVOLTAIC PANELS (TYPICAL)

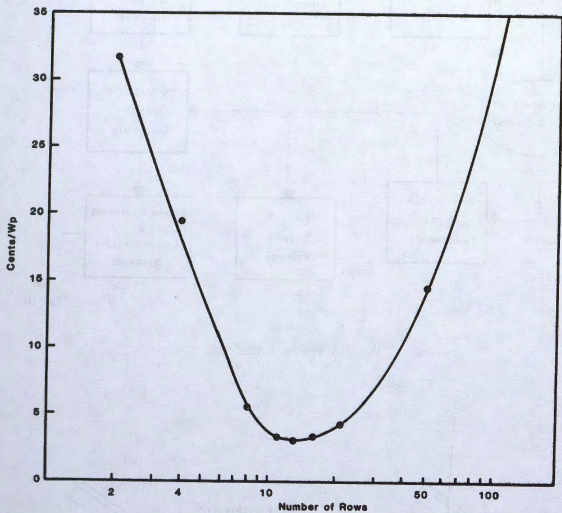


Figure 3. COPPER COSTS FOR 400-kWp ARRAY MODULE AS A FUNCTION OF NUMBER OF ROWS

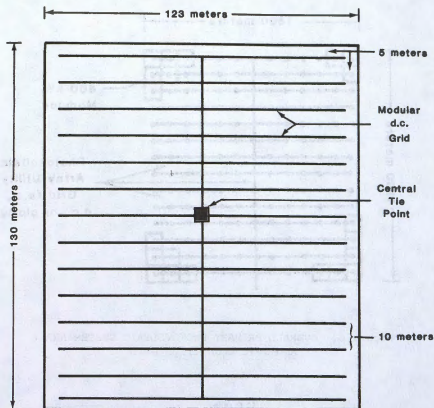


Figure 4. THE 400-kWp PV ARRAY MODULE

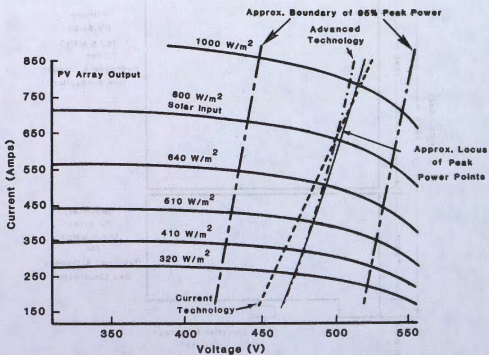


Figure 5. OPERATING REGION OF A WELL-MATCHED, DIRECT-CONNECTED, PHOTOVOLTAIC/WATER ELECTROLYZER

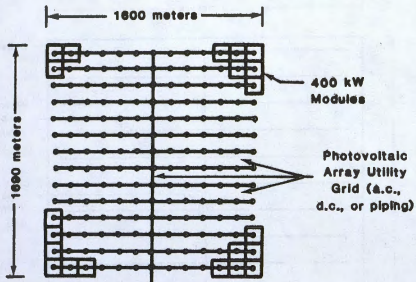


Figure 6. OVERALL PRIMARY PHOTOVOLTAIC SYSTEM ARRAY AND INTERCONNECTION GRID

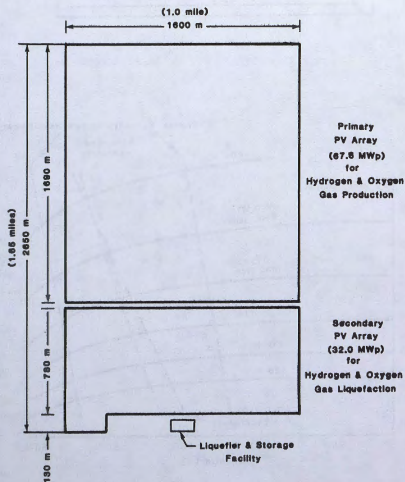


Figure 7. OVERALL PHYSICAL LAYOUT OF FACILITY