

SOLAR-HYDROGEN ELECTRICITY GENERATION IN THE CONTEXT OF GLOBAL CO₂ EMISSION REDUCTION

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Abstract. The relative costs and CO₂ emission reduction benefits of advanced centralized fossil fuel electricity generation, hybrid photovoltaic-fossil fuel electricity generation, and total solar electricity generation with hydrogen storage are compared. Component costs appropriate to the year 2000–2010 time frame are assumed throughout. For low insolation conditions (160 W m⁻² mean annual solar radiation), photovoltaic electricity could cost 5–13 cents/kWh by year 2000–2010, while for high insolation conditions (260 W m⁻²) the cost could be 4–9 cents/kWh. Advanced fossil fuel-based power generation should achieve efficiencies of 50% using coal and 55% using natural gas. Carbon dioxide emissions would be reduced by a factor of 2 to 3 compared to conventional coal-based electricity production in industrialized countries. In a solar-fossil fuel hybrid, some electricity would be supplied from solar energy whenever the sun is shining and remaining demand satisfied by fossil fuels. This increases total capital costs but saves on fuel costs. For low insolation conditions, the costs of electricity increases by 0–2 cents/kWh, while the cost of electricity decreases in many cases for high insolation conditions. Solar energy would provide 20% or 30% of electricity demand for the low and high insolation cases, respectively. In the solar-hydrogen energy system, some photovoltaic arrays would provide current electricity demand while others would be used to produce hydrogen electrolytically for storage and later use in fuel cells to generate electricity. Electricity costs from the solar-hydrogen system are 0.2–5.4 cents/kWh greater than from a natural gas power plant, and 1.0–4.5 cents/kWh greater than from coal plant for the cost and performance assumptions adopted here. The carbon tax required to make the solar-hydrogen system competitive with fossil fuels ranges from \$70–660/tonne, depending on the cost and performance of system components and the future price of fossil fuels.

Leakage of hydrogen from storage into the atmosphere, and the eventual transport of a portion of the leaked hydrogen to the stratosphere, would result in the formation of stratospheric water vapor. This could perturb stratospheric ozone amounts and contribute to global warming. Order-of-magnitude calculations indicate that, for a leakage rate of 0.5% yr⁻¹ of total hydrogen production – which might be characteristic of underground hydrogen storage – the global warming effect of solar-hydrogen electricity generation is comparable to that of a natural gas-solar energy hybrid system after one year of emission, but is on the order of 1% the impact of the hybrid system at a 100 year time scale. Impacts on stratospheric ozone are likely to be minuscule.

1. Introduction

As a result of the unprecedented, rapid, and essentially irreversible nature of projected climatic change from anthropogenic greenhouse gas emissions, and the associated risks to human societies and ecosystems, there is growing political recognition of the need to limit and/or reduce greenhouse gas emissions so as to stabilize their atmospheric concentrations. In the case of CO₂, stabilization of concentration will require emission reductions of 50–60% within a few decades based on present understanding, followed by more gradual reductions thereafter as natural carbon sinks decrease in strength. There is universal agreement that the single most important and most cost-effective short-term (10–15 years) measure to

reduce greenhouse gas emissions is to improve the efficiency with which energy is transformed and used in all its applications (see Goldemberg *et al.*, 1988; Johansson *et al.*, 1989; and Krause *et al.*, 1990 for recent analyses of the efficiency potential). In the short to medium term (10–20 years), renewable, non-fossil fuel energy sources such as solar voltaic and solar thermal electricity generation, ocean thermal energy conversion (OTEC), and biomass energy conversion could begin to play a role in reducing the need for fossil fuels. Switching from coal to natural gas, to the extent that supplies permit, can also reduce carbon dioxide emissions in the medium term.

In the longer term, measures will be needed to shift away from fossil fuels altogether (although the final stages could proceed slowly, at a rate governed by the decreasing rate of CO₂ absorption by the oceans and other sinks, as discussed in Harvey, 1989 and 1990). Most renewable energy sources, however, are constrained by problems of intermittency and lack of portability. A convenient energy medium is needed to store energy from intermittent sources such as solar energy, for global transfer of energy from solar energy-rich to solar energy-poor regions or from mid-ocean OTEC energy sources to continental energy markets, and for use in the transportation sector.

Hydrogen provides what in many respects is an ideal energy carrier or energy currency. Electricity produced from renewable energy sources could be used to make hydrogen and oxygen by electrolysis of water, and the hydrogen recombined with oxygen in a fuel cell to generate electricity when needed. Hydrogen could also be used directly as both a surface and air transportation fuel, and could be distributed and used in most or all of the ways in which natural gas is now used. Several hydrogen pipelines already exist and have yielded a wealth of operating experience; for distances greater than about 1000 km, the cost and energy losses associated with hydrogen transport by pipeline are estimated to be greater than for natural gas transport (Carpetis, 1988) but less than those associated with high voltage electricity transfer (Veziroglu, 1987). Hydrogen and electricity would serve as complementary energy currencies, each being directly used in the applications for which it is most suited, and each being transformable to the other. An energy system based on hydrogen produced from renewable energy sources is commonly referred to as a 'hydrogen economy' (see reviews by Bockris and Veziroglu, 1985; and Veziroglu, 1987).

This paper focuses on one particular element of a hydrogen economy: The use of hydrogen as a storage medium in providing a continuous supply of electricity from solar energy. The relative costs of solar-hydrogen, a solar-fossil fuel hybrid, and advanced fossil fuel generation technologies are compared using a consistent set of assumptions appropriate to the year 2000–2010 time frame, and the differences in carbon dioxide emissions are determined. Alternative methods of providing continuous, solar-energy based electricity – namely, solar thermal power with thermal energy storage, and biomass generation – are briefly discussed. Finally, the paper closes with a discussion of the potential impacts of leakage of hydrogen into the atmosphere on stratospheric ozone and surface climate.

One of the prime purposes of this paper is to provide guidance in the cost of the 'backstop' carbon-free, unlimited energy source for electricity used in various economic models which attempt to project the long-term costs of significant CO₂ emission reductions (i.e.: Manne and Richels, 1990, 1992). Indeed, the very use of a single backstop technology price is unjustified, since a continuum of technical options, with progressively greater CO₂ emission reductions, exists. Given this purpose, the ad hoc nature of the backstop prices adopted by economists so far, and the uncertainties in the costs and performance of individual technologies, the calculations given below are kept simple and general. Much more detailed utility costing algorithms exist and have been applied to site-specific examples.

2. Emerging Fossil Fuel Technologies

Fossil fuels supplied 64% of global electricity production in 1986 (U.N., 1988), much of it from coal. Conventional coal-fired power plants have efficiencies of about 33% in industrialized countries but as low as 25–28% in developing countries; Integrated Coal Gasification-Combined Cycle (IGCC) power plants should yield efficiencies from 38% to as high as 45% (U.S. DOE, 1993a), while emerging fuel cell technologies using gasified coal promise electricity generation efficiencies of about 50% (U.S. DOE, 1989), giving up to a factor of two reduction of CO₂ emissions per kWh (kilowatt-hour) electricity. The development of advanced combined gas and steam turbines powered by natural gas, and having a total electricity generation efficiency of 48% (based on the higher heating value of natural gas), has made natural gas highly competitive for baseload electricity generation (Williams and Larson, 1989). With ceramic turbines, which permit higher inlet temperatures, advanced natural gas combined cycle turbines should achieve efficiencies of 54–59% by 2010 (Williams, personal communication, 1993). Natural gas-powered fuel cells should give efficiencies on the order of 55% (Appleby, 1988), and as high as 70% if waste heat is used to drive a steam turbine in a so-called bottoming cycle. Given a CO₂ emission factor of 13.6 kg C/GJ for natural gas and 25 kg C/GJ for coal, replacement of existing coal-fired power plants with advanced combined cycle or fuel cell power plants fuelled by natural gas would reduce CO₂ emissions per kWh by a factor of three to five.

IGCC power plants should achieve costs of around \$1450/kW (Streets *et al.*, 1991), while gas combined cycle power plants have been built for as low as \$650/kW. The \$800/kW difference between these two costs is associated with handling and gasification of coal. Although conventional coal power plants are less costly, IGCC achieves significantly lower emissions of acid rain precursors (98% sulphur removal and over 90% NO_x reduction) – a factor which is assumed here to eventually eliminate conventional power plants from consideration for new coal-based power. As discussed below, fuel cell power plant costs of \$650–850/kW using natural gas might be achievable, and a markup for gasification of coal comparable to that required for IGCC plants should be applicable when coal is used to power

fuel cells. Indeed, coal processing costs using fuel cells might be somewhat larger than in IGCC plants because of the need to reduce the sulphur content of the gasified coal to below 1 ppm (at least for use in molten carbonate fuel cells). It is unclear whether fuel cells will become competitive with natural gas combined cycle and IGCC in large, centralized power plants. The likely niche for fuel cells using fossil fuels will be small (up to a few MW), dispersed applications where savings in electricity transmission and distribution costs can offset modestly higher power plant capital costs. However, fuel cells using hydrogen will be considerably less expensive, and more efficient, than fuel cells using natural gas or coal, and would be the technology of choice if hydrogen is the initial fuel.

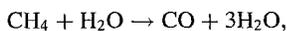
2.1. FUEL CELL TYPES AND CHARACTERISTICS

A fuel cell consists of an anode and a cathode emersed in an electrolyte (an ion conducting substance). A hydrogen-rich fuel is added to the anode, oxygen is added to the cathode, and an external current is created which runs from the anode to the cathode and is completed by the flow of ions within the electrolyte. The voltage potential created by a single fuel cell is 0.7–0.9 V, so fuel cells must be joined in series to get higher voltages, creating a fuel cell stack. The power generated by a fuel cell is given by the product of voltage and current, the latter given by the product of current density (amps m^{-2}) across the fuel cell plates and the plate area.

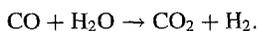
There are five types of fuel cells in use or under development, which are listed in Table I along with the reactions occurring at the anode and cathode and the electrolyte conducting ion. Alkaline fuel cells (AFC's) require pure hydrogen, but the other fuel cells can be fed on pure hydrogen or a hydrogen-rich gas, the latter produced by coal gasification or by steam reforming of methane*. Fuel cell systems powered by coal or natural gas have three main components: a fuel processing component, in which a hydrogen-rich gas is produced, the fuel cell stack, and a power conditioning unit to convert from DC to AC electricity.

The efficiency of a fuel cell system involves tradeoffs with operating lifetime and capital costs. Waste heat from the fuel cell stack can be used for fuel processing, thereby increasing the system efficiency, but with increased capital cost and complexity. Increasing operating temperature leads to better use of waste heat in fuel processing and hence higher system efficiency, but results in a shorter lifetime. Reducing the current density leads to higher efficiency because resistance losses are reduced, but requires a greater cell area and hence greater cell and building capital costs for the same power output.

* Methane reforming involves two steps, the first being:



followed by a two stage water shift reaction:



Coal gasification can also be pushed to an output consisting essentially of CO_2 and H_2 .

TABLE I
Chemical reactions occurring at the anode and cathode of different fuel cells

Fuel cell type	Anodic reaction	Cathodic reaction	Electrolyte conducting ion
AFC	$H_2 + 2OH^- \rightarrow 2H_2O + 2e^-$	$\frac{1}{2}O_2 + H_2O + 2e^- \rightarrow 2OH^-$	OH^-
SPFC	$H_2 \rightarrow 2H^+ + 2e^-$	$O_2 + 2H^+ + 2e^- \rightarrow H_2O$	H^+
PAFC	$H_2 \rightarrow 2H^+ + 2e^-$	$\frac{1}{2}O_2 + 2H^+ + 2e^- \rightarrow H_2O$	H^+
MCFC	$H_2 + CO_3^{2-} \rightarrow H_2O + CO_2 + 2e^-$ $CO + CO_3^{2-} \rightarrow 2CO_2 + 2e^-$	$CO_2 + \frac{1}{2}O_2 + 2e^- \rightarrow CO_3^{2-}$	CO_3^{2-}
SOFC	$2H_2 + 2O^{2-} \rightarrow 2H_2O + 4e^-$ $2CO + 2O^{2-} \rightarrow 2CO_2 + 4e^-$	$O_2 + 4e^- \rightarrow 2O^{2-}$	O^{2-}

AFC = Alkaline fuel cell.

SPFC = Solid polymer fuel cell.

PAFC = Phosphoric acid fuel cell.

MCFC = Molten carbonate fuel cell.

SOFC = Solid oxide fuel cell.

Fuel processing is simpler using natural gas than using coal, such that natural gas systems will have greater efficiency and lower capital cost compared to coal-based systems. Efficiencies are higher still and capital costs lower using pure hydrogen, and efficiencies are higher using pure oxygen rather than air at the cathode. Table II compares the range of efficiencies and operating temperatures for different fuel cells using coal, natural gas, and pure hydrogen as input fuels, while Figure 1 shows the variation of system efficiency with current density for the PAFC, SOFC, and MCFC using natural gas. In the high temperature fuel cells – SOFC's and MCFC's – internal rather than external methane reforming is possible, leading to a substantially higher efficiency.

Appleby (1994) discusses the tradeoffs between fuel cell efficiency, on the one hand, and cost and complexity. Given these tradeoffs, one can expect practical fuel cell efficiencies of 50% using coal, 55% using methane, and 60% using pure hydrogen. Laboratory AFC's and SPFC's using pure hydrogen and oxygen had achieved an efficiency of 60% by 1989 (Schnurnberger, personal communication, 1989). Even higher electrical generation efficiencies – on the order of 65–70% – might be achievable with a combined fuel cell-gas turbine system (Blomen, 1992; Appleby, 1994).

2.2. FUEL CELL STATUS AND CAPITAL COST

Natural gas-powered PAFC's are commercially available for power generation in 200 kW sizes with an AC electrical generation efficiency of 40% and sell for about \$2500/kW. Efforts are underway to develop multi-MW size units. A consortium of American and Canadian electric and gas utilities is supporting the development of MCFC's with the expectation that the first 50 2 MW units will have an installed

TABLE II

Technical characteristics of fuel cells. Efficiencies and operating temperatures are from Ontario Hydro (1991), except for MCFC and SOFC efficiencies, which are based on sources cited in the main text. NG = Natural Gas

Fuel cell type	Electricity generation efficiency	Fuel/oxidant	Tolerance for			Precious catalyst required?	Operating temperature
			CO	CO ₂	S		
AFC	55-65	H ₂ /O ₂	No	No	No	No ¹	50-260 °C
SPFC	55	H ₂ /O ₂	1-2%	Yes	Yes	Yes	80-120 °C
	40	NG/air					
PAFC	50	H ₂ /O ₂	1%	Yes	No	Yes	190-210 °C
	40	NG/air					
MCFC	60	H ₂ /O ₂					
	54-60	NG/air	Yes	Yes	No	No	650 °C
	45	Coal/air					
SOFC	60	H ₂ /O ₂					
	50	NG/air	Yes	Yes	Yes ²	No	1000 °C
	45	Coal/air					

¹ Might be required for long life.

² Appleby (personal communication, 1992) questions developers' claims that SOFC can tolerate S impurities.

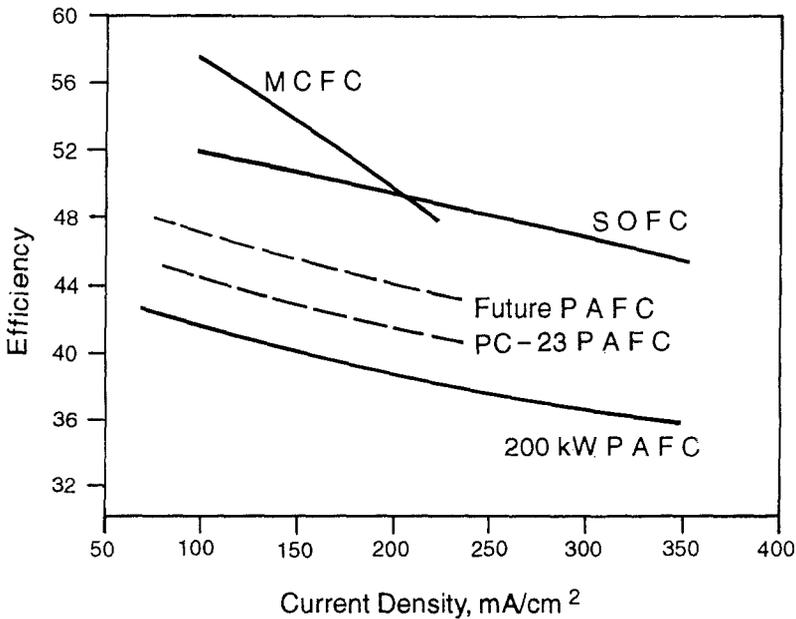


Fig. 1. Efficiency of electricity generation for various natural gas-fuelled fuel cells, from Appleby (1988). See Table I for explanation of abbreviations.

cost of \$1500/kW and will be commercially available by the mid to late 1990's (Serfass and Glenn, 1992). It is also hoped that SOFC's will become commercially available before the end of the 1990's, with a near-term price of about \$1200–1300/kW (Dollard and Parker, 1991; Dollard, 1992).

Fuel cells lend themselves to mass production, and several workers project longer term costs for both PAFC's and MCFC's of \$650–1000/kW (Gillis, 1988; Spillers, 1988; Appleby, 1988). Appleby (personal communication, 1992) indicates that \$400/kW is conceivable for MCFC's fuelled by natural gas, of which about $\frac{1}{4}$ to $\frac{1}{3}$ would be associated with fuel processing – a step which can be eliminated in fuel cells supplied directly with hydrogen.

A problem still plaguing fuel cells is a tendency for initial efficiencies to decrease over time. For example, a fuel cell having an initial efficiency of 60% might drop to less than 50% after 20,000 hours operation time (Schnumberger, personal communication, 1989). Others claim less of an efficiency drop, but this depends on on/off cycling.

3. Electricity Production from Solar Energy

The main cost components for photovoltaic (PV) electricity production are the cost of individual solar modules, area-related balance of system costs such as support structures and land, and power conditioning costs to convert the DC output of PV modules to high-quality AC electricity. Inasmuch as the power output from PV modules depends on the incident solar radiation, costs are traditionally given per peak watt (W_p), where a peak watt is defined as the module output assuming an incident solar radiation I_p of 1000 W m^{-2} .

Thin film technologies such as amorphous-Silicon (a-Si), cadmium telluride (CdTe), and multi-layer a-Si/copper indium diselenide (CuInSe_2), are competing with crystalline Si to be the most cost-effective PV technology. Although greater efficiencies are attainable using crystalline Si, manufacturing costs and energy inputs are likely to be substantially lower using thin film technologies (Carlson, 1989). A problem currently plaguing a-Si cells is that absorption of light induces structural defects which cause the initial light-to-electricity conversion efficiency to decrease. This degradation is not observed in CuInSe_2 or CdTe cells. In 1992, a laboratory CdTe cell achieved an efficiency of 15.8%, a CuInSe_2 module achieved an efficiency of 9.7%, and a-Si modules achieved stabilized efficiencies of greater than 8%. It is not clear at the moment which PV technology will be most cost-effective, but it is reasonable to expect that module efficiencies of 15–20% can be achieved (U.S. DOE, 1991, 1993b), perhaps by 2000–2010.

3.1. LEVELIZED COST OF PHOTOVOLTAIC ELECTRICITY

The levelized cost of electricity refers to the uniform price at which the electricity produced from a power system must be sold in order to recapture the total costs of producing the electricity over the lifetime of the system, including interest charges.

The levelized cost (\$/kWh) of producing photovoltaic AC electricity is given by the equation:

$$C = \frac{\{(CRC + INS)(1 + ID)(C_m + C_b + C_p) + OM_{PV}\}I_p}{A_w\eta_{BOS}}, \quad (1)$$

where

CRC = cost recovery factor (yr^{-1});

$$= i / (1 - (1 + i)^{-N});$$

i = real interest rate (or opportunity cost of money)

N = lifespan (years) of power plant;

INS = insurance rate (yr^{-1});

ID = indirect cost factor to cover site engineering, maintenance of inventories, and contingencies;

C_m = module cost (\$/W_p DC)

$$= (\$/\text{m}^2) / (\eta_m I_p);$$

C_b = balance of system costs (\$/W_p DC)

$$= (\$/\text{m}^2) / (\eta_m I_p);$$

C_p = DC/AC power conditioning cost (\$/W_p DC);

OM_{PV} = operation and maintenance cost (\$/W_p(DC)-yr)

$$= (\$/\text{m}^2) / (\eta_m I_p);$$

η_m = module efficiency;

η_{BOS} = balance of system efficiency;

I_p = peak insolation, W m⁻²;

A_w = $H_{yr}(\text{hr yr}^{-1}) \times I_a(\text{W m}^{-2}) / 1000(\text{W kW}^{-1})$

$$= \text{kWh}/\text{m}^2\text{-yr};$$

H_{yr} = number of hours in a year = 8760 hr yr⁻¹; and

I_a = mean annual insolation on the module, W m⁻², averaged diurnally and over all seasons.

This equation is similar to an equation for DC electricity given in Ogden and Williams (1989).

The U.S. DOE has set the following performance and cost targets (1985\$) for the year 2000 (U.S. DOE, 1987, 1988):

- flat plate module costs of \$40–80/m²;
- balance of system costs of \$50/m² for non-solar tracking systems;
- operation and maintenance (O & M) costs of \$1.10/m²-yr;
- module efficiencies of 0.10–0.25;
- balance of system efficiency of 0.85 (includes losses for DC/AC conversion);
- power conditioning costs of \$150/kW AC.

These projections are supported by the recent track record and industry projections (Carlson, 1990).

Kelly (1992) and Carlson and Wagner (1992) provide a breakdown of the factors contributing to PV module costs, with Kelly (1992) suggesting total costs in the

range \$44–62/m² for large scale production of thin film modules. Current thin film modules cost about \$400/m² (Zweibel and Barnett, 1992).

Ogden and Williams (1989) argue that, with innovative designs, balance of system (BOS) costs in non-roof top systems could be as low as \$33/m², and Kelly (1992) summarizes the results of several design studies which give BOS costs from \$40/m² to \$80/m². Recent BOS costs for fixed, tilted, flat-plate utility systems have been as low as \$40–100/m² (Williams, personal communication, 1993), while roof-top systems have been installed with BOS costs of \$57/m² and are projected to drop to as low as \$13/m².

Power conditioning currently costs \$400–1000/kW but should drop to \$100/kW – exceeding the DOE goal – by the mid 1990's according to Kelly (1992). The present indirect cost factor *ID* is about 0.5, but an eventual value of 0.25 is considered feasible (Gary Jones, personal communication, 1989; Kelly, 1992).

In addition to these cost components, interest or discount rates have a considerable effect on levelized electricity cost. Here, we shall consider real (nominal minus inflationary) discount rates of 5% and 10%. The former is appropriate in developed countries, while the latter might be more appropriate in developing countries, where capital is less plentiful.

Solar modules can be placed horizontally, inclined at the latitude angle with zero azimuth (which maximizes mean annual incident solar radiation for fixed modules), or made to track the sun with a two-axis tracking system. BOS costs are likely to be similar for the first two cases, but two axis tracking would double projected BOS costs from \$50/m² to \$100/m² according to the U.S. DOE (1987). Table III gives the mean annual solar radiation incident on horizontal, inclined, and sun-tracking modules for low latitude (30°) and middle latitude (45°) cases (see Appendix One for calculation details). The low latitude case corresponds to sunny skies, while for the middle latitude case the clear sky radiation was multiplied by 0.73 at all times. The resultant mean annual radiation on horizontal modules at 30° (about 260 W m⁻²) corresponds to observed mean annual insolation in the U.S. southwest or in the Sahara desert and Saudi Arabia, while the middle latitude insolation (about 160 W m⁻²) corresponds to that observed in the northeast U.S. (see Landsberg, 1960). Use of inclined modules increases mean annual insolation on the modules by 11% for the low latitude case and by 26% for the middle latitude case, thereby reducing the difference in incident solar energy between low and middle latitudes. In addition to increasing the mean annual incident solar radiation, inclining the modules at the latitude angle reduces the seasonal variation of daily incident radiation, as illustrated in Figure 2.

Table IV gives AC electricity costs computed from Equation (1) for modules costing \$40 and \$80/m², module efficiencies of 15% and 20%, BOS costs of \$50/m² for horizontal and inclined modules but \$100/m² for sun-tracking modules, BOS efficiency of 85%, O & M costs of \$1.10/m²-yr, and power conditioning costs of \$130/kW DC (about \$150/kW AC). A system lifetime of 20 years (a cautious assumption), 0.5% yr⁻¹ insurance rate, and 20% backup capacity are assumed.

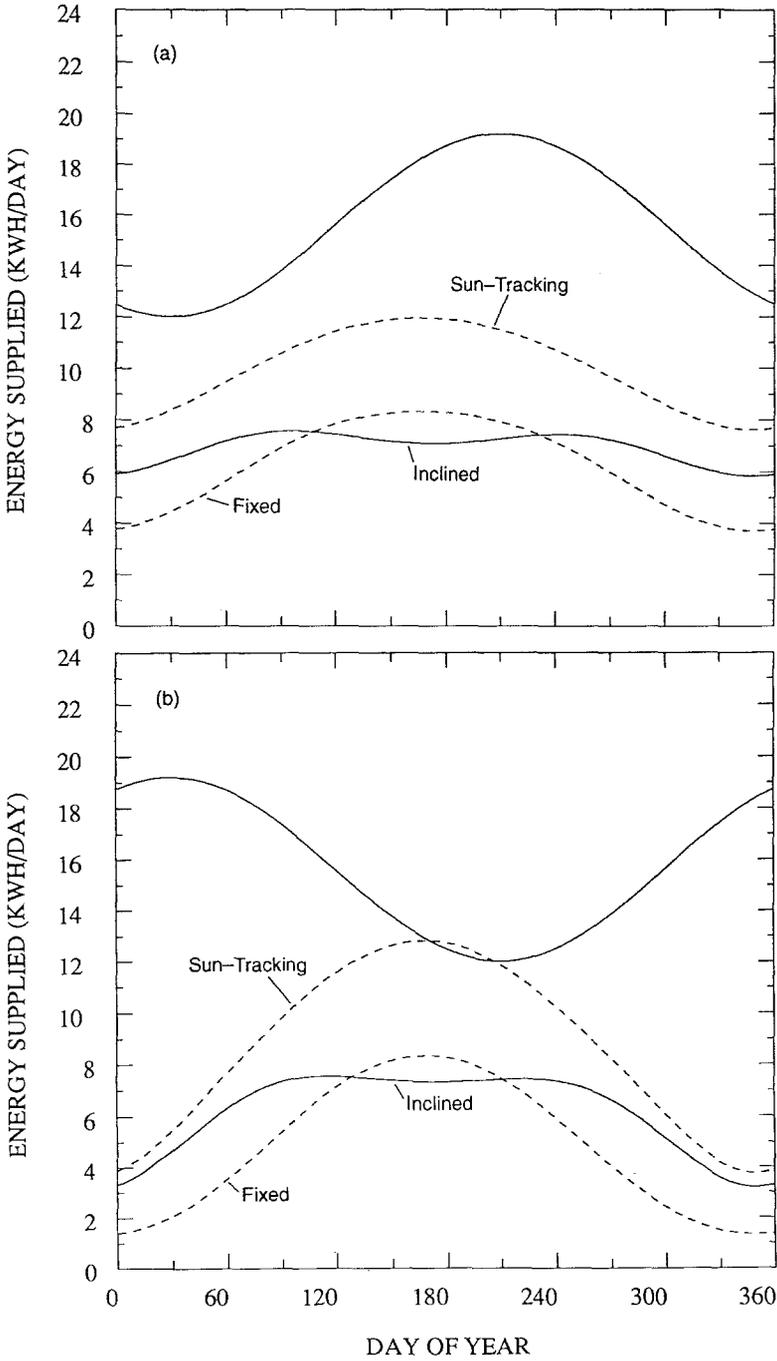


Fig. 2. Seasonal variation of daily solar radiation (kWh) incident on horizontal, inclined, and sun-tracking modules for (a) low; and (b) middle latitude cases.

TABLE III

Comparison of mean annual incident solar radiation, peak solar radiation, PV and fossil scaling factors (s_{pv} and s_{ff}), and fraction of total electricity supplied and hybrid solar-fossil fuel electricity costs for horizontal, inclined, and sun-tracking modules

Case	Mean annual insolation (W m^{-2})	Peak insolation (W m^{-2})	s_{pv}	Scaling factor s_{ff}	Solar electricity fraction (%)
<i>Low latitude case:</i>					
Horizontal	261	996	0.757	0.915	30
Inclined	291	1044	0.624	0.923	28
Sun-tracking	419	1138	0.526	0.915	34
<i>High latitude case:</i>					
Horizontal	160	945	0.666	0.981	16
Inclined	202	1054	0.617	0.980	19
Sun-tracking	286	1105	0.453	0.980	20

The computed levelized electricity cost ranges from \$0.037/kWh to \$0.089/kWh for the low latitude case, and from \$0.054/kWh to \$0.128/kWh for the middle latitude case, assuming fixed inclined modules. By comparison, the current cost of photovoltaic electricity in the SW U.S. is \$0.25–0.35/kWh (Kelly, 1992). The costs computed here do not include administrative and transmission costs.

3.2. HYBRID SOLAR-FOSSIL FUEL ELECTRICITY COSTS

In this section the cost of electricity from a dedicated fossil fuel power plant is compared with the average cost of electricity supplied by a hybrid solar-fossil fuel system. Due to fluctuating electricity demand, the mix of power sources in a utility grid is rarely running at full capacity. Addition of solar capacity, to the extent that a guaranteed minimum amount of solar electricity is available at times of peak demand, allows downsizing of the fossil fuel-based capacity and saves on fuel costs, while adding new capital cost components.

As a first approximation of the effect on electricity costs of adding solar PV generating capacity, we shall consider a hybrid system in which the solar component is scaled such that the PV power supply never exceeds electricity demand. Since peak PV power output typically coincides with times of less than peak demand, the entire PV system must be scaled by a factor s_{pv} (< 1) compared to a system where peak PV power equals peak demand. The fossil fuel capacity is scaled by a factor s_{ff} (≤ 1) depending on if, and how much, solar electricity is available at times of peak demand. We shall assume that mean annual electricity demand is 0.65 of peak demand, with diurnally averaged demand varying seasonally between 0.5 and 0.8 of peak demand, and a diurnal variation of amplitude 0.2 of peak demand

TABLE IV

Illustrative costs of solar electricity for middle latitude and low latitude sites, solar module costs of \$40/m² and \$80/m², module efficiencies of 15% and 20%, interest rates of 5% and 10%, and solar balance of system costs of \$50/m² for horizontal (Hor) and inclined (Inc) modules and \$100/m² for sun-tracking (Sun) modules. 20% backup capacity is assumed

Module cost (\$/m ²)	Module efficiency	Interest rate	Electricity cost (cents/kWh)					
			Low latitude			Middle latitude		
			Hor	Inc	Sun	Hor	Inc	Sun
40	15	5	5.2	4.7	4.7	8.5	6.8	6.9
		10	7.3	6.6	6.6	11.8	9.5	9.7
40	20	5	4.1	3.7	3.7	6.7	5.4	5.4
		10	5.8	5.2	5.2	9.3	7.6	7.6
80	15	5	7.0	6.3	5.8	11.3	9.1	8.5
		10	9.8	8.9	8.2	15.9	12.8	12.0
80	20	5	5.5	4.9	4.5	8.8	7.1	6.6
		10	7.7	6.9	6.4	12.4	10.0	9.3

superimposed on the seasonal variation. Daily peak demand is assumed to occur at 1500 hours, while peak seasonal demand is assumed to occur on 1 August for the low latitude case (corresponding to a summer air conditioning peak) and on 1 February for the middle latitude case (corresponding to a winter heating peak). Both seasonal and diurnal variations are assumed to be sinusoidal, for simplicity. These approximations are crude by utility standards, but more detailed calculations are not justified here, given uncertainties in future costs and efficiencies. The concurrent variation of solar radiation is computed as described in Appendix One.

Even with full fossil fuel backup of the PV component, a small amount of electricity storage will be required due to the lag between the response of the fossil fuel electricity source and rapid fluctuations in PV power. However, the need for storage can be reduced in a distributed PV system, in which large, rapid variations in total power output due to transient shading are avoided. Given the uncertainties in other cost components, we neglect this storage.

Table III gives the peak insolation, required scaling factors s_{pv} and s_{ff} , and the fraction of total electricity demand met by solar energy for horizontal, inclined, and sun-tracking modules for the low and middle latitude cases. Solar energy provides 28–34% of total electricity demand for the low latitude case, and 16–20% for the middle latitude case. However, given the covariation of insolation and electricity demand assumed here, the required fossil fuel capacity is reduced by less than 10% for the low latitude case and by only 2% for the middle latitude case.

The levelized cost (\$/kWh) of electricity generated from fossil fuels is given by:

$$C = \frac{(CRF + INS)CC_{ff} + OM_{ff}}{H_{yr}CP} + C_{fuel} , \quad (2)$$

where

CC_{ff} = fossil fuel power plant capital cost, \$/kW AC;

OM_{ff} = operation and maintenance cost, \$/kW-yr;

CP = capacity factor = 0.65;

C_{fuel} = fuel cost, \$/kWh;

= 0.001 GJ/MJ \times cost in \$/GJ \times 3.6 MJ/kWh/ η_{ff} ; and

η_{ff} = fossil fuel electricity generation efficiency,

and other terms are as previously defined. The following assumptions are made:

- capital costs of \$650–850/kW for natural gas and \$1450–1650/kW for coal;
- operation and maintenance costs of \$20–40/kW-yr;*;
- fuel costs of \$3–7/GJ using natural gas,** and \$1.5–2.5/GJ using coal;***
- efficiencies of 50–60% using coal and 55–65% using natural gas; and
- the same interest rate (5% and 10%), insurance rate (0.5% yr⁻¹), and system lifetime (20 years) as for the PV system.

Table V gives the levelized cost of electricity for a pure fossil fuel system, assuming an additional 20% markup on capital and O & M costs to allow for backup capacity. Electricity costs range from 3.6 cents/kWh to 6.5 cents/kWh using natural gas, and from 4.5 cents/kWh to 5.6 cents/kWh using coal, in both cases assuming a 5% interest rate.

In computing the average cost of electricity for the hybrid system, we assume that the 20% overall backup factor, used above in computing individual solar and fossil fuel electricity costs, is provided entirely by the fossil fuel component. The cost of electricity in the hybrid system is then given by:

$$\frac{(CRF + INS)\{s_{PV}(1 + ID)(C_m + C_b + C_p)I_p/\eta_{BOS} + (s_{ff} + B)CC_{ff}\} + s_{PV}(1 + ID)OM_{PV} + (s_{ff} + B)OM_{ff}}{H_{yr}CP} +$$

$$+ F_{ff}C_{fuel} = F_{PV}E_{PV} + (s_{ff} + B)E_{ff} + F_{ff}C_{fuel} ,$$

* Such costs are low if the technology is the fuel cell, where a complete stack replacement will be required, at best, once every 10–15 years (Appleby, 1992), but are appropriate for advanced combined cycle or IGCC systems (based on Streets *et al.*, 1991).

** The Canadian National Energy Board (NEB, 1988) projects natural gas prices in Canada to major users like utilities of \$2.5–3.5/GJ by 2005. Higher prices may occur by 2005 as a result of major efforts to reduce greenhouse gas emissions through fuel switching, and still higher prices can be expected on a longer time scale.

*** Based on NEB (1988), and assumed not to increase over time due to depressed demand for coal.

TABLE V

Illustrative electricity costs for advanced fossil fuel systems with a capacity factor of 0.65, for real interest rates of 5% and 10% with 20% backup capacity

Capital cost (\$/kW)	O & M (\$/kW-yr)	Efficiency	Fuel cost (\$/GJ)	Electricity cost (cents/kWh) for interest rates of:	
				5%	10%
Natural gas:					
650	20	0.55	3	3.6	4.1
			5	4.9	5.4
			7	6.2	6.7
850	20	0.55	3	3.9	4.6
			5	5.2	5.9
			7	6.5	7.2
Coal:					
1450	40	50	1.5	4.5	6.6
			2.5	5.3	7.2
1650			1.5	4.9	6.2
			2.5	5.6	6.9

where F_{PV} and F_{ff} are the fractions of electricity supplied by solar energy and fossil fuels, respectively, E_{PV} is the cost of PV electricity as given by Equation (1), E_{ff} is the cost of fossil fuel electricity as given by Equation (2) with fuel costs excluded, and $B = 0.2$ is the system backup factor.

Table VI gives the difference between the average electricity cost for the hybrid system and the cost for the pure fossil fuel system for inclined modules, 50% (coal) or 55% (natural gas) fossil fuel efficiency, capital costs (including power conditioning and building costs) of \$650/kW AC (natural gas) or \$1450/kW AC (coal) and \$40/kW-yr operation and maintenance costs for the fossil fuel portion of the hybrid system. For the low latitude case, electricity from a hybrid natural gas-solar system costs from -0.5 to 1.4 cents/kWh more than for the pure fossil fuel system, while electricity from a hybrid coal-solar system costs 0.2 to 1.5 cents per kWh more than from a pure coal system. For the middle latitude case, electricity from a hybrid natural gas-solar system costs up to 1.6 cents per kWh more than from a pure natural gas system, while electricity from a hybrid coal-solar system costs 0.5 to 1.8 cents per kWh more than from a pure coal system.

Neither the hybrid nor fossil fuel system costs include administrative and transmission costs. To the extent that these costs are the same for both systems, their inclusion will not affect the cost differences cited here. However, transmission costs would be greater for the hybrid system if the hybrid power plant is situated

TABLE VI

Extra cost of electricity from a hybrid solar-fossil fuel system compared to the cost of a pure fossil fuel system. Results are given for inclined modules with a balance of system cost of \$50/m², and a fossil fuel power plant efficiency of 55% (natural gas) or 50% (coal) efficiency, capital costs of \$650/kW (natural gas) or \$1450/kW (coal) fossil fuel, and O & M costs of \$20/kW-yr (natural gas) or \$40/kW-yr (coal)

Module cost (\$/m ²)	Module efficiency	Fossil fuel cost (\$/GJ)	Extra cost of electricity (cents/kWh)				
			30° latitude		45° latitude		
			5%	10%	5%	10%	
<i>Using natural gas:</i>							
40	15	3	0.5	0.9	0.7	1.1	
		5	0.1	0.5	0.4	0.9	
		7	-0.3	0.1	0.2	0.6	
	20	3	0.2	0.5	0.5	0.8	
		5	-0.2	0.2	0.2	0.6	
		7	-0.5	-0.2	-0.1	0.3	
		7	-0.5	-0.2	-0.1	0.3	
80	15	3	0.8	1.4	1.1	1.6	
		5	0.5	1.0	0.8	1.4	
		7	0.1	0.7	0.6	1.1	
	20	3	0.5	0.9	0.7	1.2	
		5	0.1	0.6	0.5	0.9	
		7	-0.2	0.2	0.2	0.7	
		7	-0.2	0.2	0.2	0.7	
<i>Using coal:</i>							
40	15	1.5	0.6	1.0	0.8	1.2	
		2.5	0.4	0.7	0.7	1.1	
	20	1.5	0.4	0.6	0.6	0.9	
		2.5	0.2	0.4	0.5	0.8	
	80	15	1.5	0.9	1.5	1.2	1.8
			2.5	0.7	1.3	1.1	1.6
20		1.5	0.6	1.0	0.9	1.3	
		2.5	0.4	0.8	0.7	1.2	

further from the demand centers than the fossil fuel plant, in order to permit utilization of desert regions. Each 1000 km extra transmission distance will add about 0.3–0.6 cents/kWh (Quinlan, pers. comm., 1992) to the cost of electricity and add about 7% to the total transmission energy loss, assuming 700 kV transmission and a resistance of 0.033153 W/amp² (Quinlan, pers. comm., 1992).

Note that the extra cost of the hybrid system is only 0.2–0.4 cents per kWh greater for the low insolation case than for the high insolation case, in spite of the fact that solar electricity is up to 6 cents per kWh more expensive for low insolation

than for high insolation. The reason for this is that (1) the solar electricity is only a small fraction of the total delivered electricity, and (2) the solar fraction is smaller for the low insolation case.

3.3. CO₂ EMISSION BENEFIT

Average direct emission factors for natural gas and coal are 13.56 kg C/GJ and 25.0 kg C/GJ, respectively, based on Marland and Rotty (1984). These emission factors should be increased to 15.9 kg C/GJ for natural gas and 26.0 kg C/GJ for coal to account for emissions associated with the extraction, processing, and transportation of these fuels (see Appendix Two. The appropriate markup will vary regionally). For a coal power plant at 33% efficiency, the CO₂ emission factor is 0.284 kg C/kWh. Switching to coal at 50% efficiency reduces CO₂ emissions by one third, while switching to natural gas at 55% efficiency reduces emissions by almost a factor of 3 (to 0.104 kg C/kWh). Hybridizing coal and natural gas with solar energy reduces emissions by about 20% (low insolation case) or 30% (high insolation case) – equal to the solar fraction of total electricity generated. Increasing the fossil fuel efficiency from 55% to 65% gives almost the same emission reduction as keeping the efficiency at 45% and hybridizing with solar energy for the low insolation case. Emission factors as low as 0.073 kg C/kWh are possible for the solar-natural gas hybrid with high insolation, which is a reduction by almost a factor of 4 compared to present coal-fired generating plants.

As previously noted, the efficiency of fuel cells can be increased by operating them at a lower current density, but at greater capital cost. Thus, reducing CO₂ emissions by increasing fuel cell efficiency or by hybridizing with solar energy both entail greater capital costs. One strategy, if further emission reductions are required, will be to increase fossil fuel efficiency until further increases in efficiency become more expensive than adding solar capacity.

4. Solar-Hydrogen Electricity

To compute the cost of going from a solar-fossil fuel hybrid system to a solar-hydrogen system for electricity generation, we again assume 5% and 10% real discount rates and a 20 year lifetime for all system components. We shall consider a system in which some PV arrays provide electricity to meet the current electricity demand, while other arrays power electrolyzers which produce hydrogen for storage and later conversion back to electricity. Experimental systems involving the direct conversion of sunlight to hydrogen via electrolysis, hydrogen storage, and conversion back to electricity, are currently being tested (Winter and Fuchs, 1991; Brinner *et al.*, 1992; Lehman and Chamberlin, 1991, 1992).

Large scale use of batteries is not likely to be a viable alternative to hydrogen energy storage. Current costs for both lead acid and NaS batteries are about \$100/kWh (Appleyard, 1992). As shown below, electricity equivalent to about 10% of annual use would need to be stored at any one time for the low latitude case.

This amounts to about 500 kWh storage capacity required per kW of peak demand, at a cost of \$50,000! However, this does not preclude use of batteries for short term (minutes) energy storage as part of a solar-hydrogen system.

As PV modules produce DC current, and DC current is required as electrolyzer input, the PV modules and electrolyzers can be directly coupled without the need for power conditioning. As incident solar radiation increases, both the PV current I and voltage V increase; power output is maximized if I and V vary in such a manner as to maximize their product. Increasing power input to an electrolyzer also entails increasing I and V ; the characteristic I - V variation for an electrolyzer closely matches the I - V solar module variation required for maximum power output (Siegel and Schott, 1988). Photovoltaic modules and electrolyzers can be directly coupled with no more than a 10% energy loss compared to the maximum power output attainable from a PV module, and with only 1% energy loss with active electronic control (Schnurnberger *et al.*, 1988). Here, we shall assume a module-electrolyzer coupling efficiency η_{me} of 95%, instead of the balance of system efficiency η_{BOS} of 85% assumed for DC/AC power conditioning.

Further energy losses occur during electrolysis, in storing hydrogen, and in converting the hydrogen back to electricity in fuel cells. These losses shall be represented by efficiencies η_e , η_s , and η_{fd} , respectively. In addition to the PV module costs, further capital costs are associated with the electrolyzers, storage medium, fuel cells, and buildings to house the electrolyzers and fuel cells. We shall briefly discuss these efficiencies and costs.

4.1. ELECTROLYZER COST AND EFFICIENCY

Ogden and Williams (1989) summarize industry-based capital cost estimates for electrolysis plants using advanced alkaline or solid polymer electrolyzers. For 2 MW H_2 output with a plant efficiency of 80%, estimated plant capital costs range from \$320/kW H_2 to \$380/kW H_2 , with module costs constituting \$200–250/kW H_2 . Solid oxide electrolyzers are also expected to reach a cost of \$250/kW H_2 (Leach and Copeland, 1986). Module cost can be reduced by 25% if DC rather than AC power is supplied to the electrolyzer (as would be supplied by dedicated solar electricity), as this eliminates the need for an AC/DC rectifier. For 10 MW facilities, Ogden and Williams assume electrolyzer module costs of \$170/kW DC input (about \$210/kW H_2 output with 80% efficiency) and total plant costs of about \$250/kW DC (about \$310/kW H_2). As with fuel cells, electrolyzer efficiency involves a trade off with capital costs: Efficiency can be increased by operating the cells at a lower current density, but this requires greater cell area for the same power input. The best efficiency attained so far is about 82%, with practical efficiencies of about 75%. Advanced alkaline electrolyzers are expected to achieve efficiencies of 93–98% at a current density of 2000 A m⁻² (the current standard) (Wendt and Bauer, 1988).

TABLE VII

Annual hydrogen production, seasonal storage capacity (S_s), diurnal storage capacity (S_d) (all in kWh H₂); seasonal (P_s) and diurnal (P_d) charge or discharge rates (kW H₂), seasonal storage capacity as a fraction of annual hydrogen production (f_s), average amount of hydrogen in seasonal storage as a fraction of annual hydrogen production (f), number of PV units required (N_1) and maximum number of PV units coupled to electrolyzers (N_2) at any given time. A fuel cell efficiency of 60% is assumed

Module configuration	Annual H ₂ production	Capacity		Maximum charge rate		f_s	f	N_1	N_2
		S_s	S_d	P_s	P_d				
Horizontal	4550	663	17.1	0.251	0.600	0.146	0.076	4.1	3.1
Inclined	4751	451	15.4	0.208	0.594	0.094	0.041	3.7	3.1
Sun-tracking	4337	422	14.1	0.155	0.378	0.098	0.050	2.5	2.0

4.2. STORAGE COST AND EFFICIENCY

Carpétis (1984, 1988) discusses the costs of hydrogen storage. Among the options available are underground storage in depleted natural gas reservoirs, salt mines, or rock caverns; or above-ground storage in pressurized vessels, as metal hydrides, in various cryo-absorber systems, or as liquid hydrogen. All hydrogen storage systems require hydrogen compression. The capital cost for hydrogen storage C_s is given by:

$$C_s = K_p P + K_c S, \quad (3)$$

where K_p and K_c are the charge/discharge power and capacity related costs, respectively, P is the peak charge or discharge rate (kW H₂), and S is the storage capacity (kWh H₂). Effective operation of a solar-hydrogen electric system will require both seasonal and diurnal storage reservoirs. Here, we shall assume underground seasonal storage with $K_p = \$30/\text{kW}$, $K_c = \$0.07/\text{kWh}$ and cryo-adsorber diurnal storage with $K_p = \$73/\text{kW}$, $K_c = \$8.7/\text{kWh}$, based on Carpétis (1984). Underground hydrogen storage requires adding a hydrogen cushion which cannot be removed from the reservoir, adding a further one-time cost which is not included here because of other uncertainties. Table VII gives the total hydrogen production and required seasonal and diurnal storage capacities and peak charge or discharge rates for horizontal, inclined, and sun-tracking PV modules. Storage system capital costs range from \$241/kW to \$277/kW.

The energy requirements e_{su} and e_{sc} for underground and cryo-adsorber energy storage are estimated by Carpétis (1984) to be 0.035 kWh_e-kWh-H₂ and 0.12 kWh_e/kWh-H₂, respectively. Since both the hydrogen and electricity used for compression are derived from the same photovoltaic system, we can represent the energy-related compression costs in terms of a storage efficiency η_s . In the case of underground storage, some hydrogen will escape from the reservoir. Carpétis

(1984) represents this in terms of the electric energy consumption ν needed to cover the reservoir loss from 1 kWh H₂ stored for one year, with $\nu = 0.1 \text{ kWh}_e/\text{kWh} (\text{H}_2)\text{-yr}$. If hydrogen is generated from electricity at 90% efficiency, this implies a leakage rate l_s of 0.09 yr^{-1} . If the average amount of hydrogen in the reservoir as a fraction of annual throughput is f , then the leakage rate as a fraction of annual throughput is $l_s f$. The average storage efficiency η_s is given by:

$$\eta_s = \frac{1}{1 + (1 - f_s)e_{sc} + f_s e_{su} + l_s f}, \quad (4)$$

where f_s is the maximum seasonal storage as a fraction of total storage (it is assumed that hydrogen flows through either the diurnal or seasonal reservoir, but not both) and e_{sc} and e_{su} have been rendered dimensionless by multiplying by an assumed electrolyzer efficiency of 0.9. The computed values of f and f_s using horizontal, inclined, and sun-tracking modules at 30° latitude are given in Table VII, and result in a storage efficiency of about 0.9.

The assumption of underground hydrogen storage places constraints on the site of electricity generation, but the next cheapest option – liquid hydrogen storage – would be an order of magnitude more expensive and entails a 33% energy penalty.

4.3. FUEL CELL COST AND EFFICIENCY

Fuel cells using hydrogen will be less expensive and more efficient than corresponding fuel cells using coal or natural gas. This occurs because the fuel processing stage can be eliminated. As well, only 80–90% of the input hydrogen at the anode is used in a fuel cell because the hydrogen concentration becomes too low at the anode exit for complete utilization (Appleby, 1988, 1994). It is possible to recycle the unused hydrogen, but in fuel cells fed by fossil fuels this requires separating the CO₂ from the H₂, adding to the system cost and complexity.

Based on optimistic natural gas fuel cell costs of \$400–600/kW (exclusive of power conditioning and the building) and the fact that 1/4 to 1/3 of this cost is due to fuel processing, which is unnecessary for fuel cells directly fuelled by hydrogen, we shall assume hydrogen fuel cell costs of \$300–500/kW costs (or \$550–750/kW including \$150/kW for power conditioning and \$100/kW for the building). Note that an electrolyzer without an AC/DC rectifier is equivalent to a hydrogen fuel cell without power conditioning but running backwards; the assumed electrolyzer capital costs (\$200–400/kW) would therefore appear to be somewhat more optimistic than the assumed hydrogen fuel cell capital costs (\$300–500/kW).

4.4. SOLAR-HYDROGEN ELECTRICITY COSTS

To determine the capital costs of a solar-hydrogen system, we must know the number of PV ‘units’ which are needed. Here, a PV unit is defined as an array large enough to produce a DC power output equal to the insolation per unit area (i.e.: 1000 W power when the insolation is 1000 W m^{-2}). Based on iterative calculations using the same variation of electricity demand assumed for the solar-fossil hybrid

system and the computed diurnal and seasonal variation of solar radiation for the low latitude case, the following quantities are calculated:

- the total number of PV units needed, N_1 , is 2.9 to 4.1 (Table VII), depending on whether horizontal, inclined, or sun-tracking modules are used;
- the maximum number of PV units coupled to electrolyzers at any given time, N_2 , is 2.0–3.1 (Table VII);
- the largest fraction N_3 of peak electricity demand that must be met by hydrogen-powered fuel cells is 0.915;
- the largest fraction of peak electricity demand supplied directly by the PV arrays at any given time, N_4 , is 1.0.

The capital cost, C_{PV} , of a PV unit, as defined above, is $(1 + ID)I_p(C_m + C_b)$. If C_{PC} is the PV power conditioning cost (\$/kW AC), C_{H_2} the H_2 production cost (\$/kW H_2 , representing electrolyzers and building), C_{FC} the fuel cell costs (\$/kW AC, including the building), and C_S the cost of hydrogen storage (\$/kW AC), then the total capital requirement, per kW peak demand, is:

$$CC_T = (1 + B_{PV})N_1C_{PV} + (1 + B_H)(N_2C_{H_2}\eta_{me}\eta_e + N_3C_{FC} + N_4C_{PC} + C_S). \quad (5)$$

A backup factor B_{PV} of 0.1 is assumed for PV arrays, rather than the usual utility system value of 0.2, because the backup arrays can be used when not needed and their energy stored. For other components (including the storage system) the backup factor B_H is assumed to be the same as in the solar-fossil hybrid system (0.2). The factor $\eta_{me}\eta_e$ converts N_2 from number of PV units to number of 1 kW(H_2) electrolyzers needed per kW peak AC demand.

Table VIII compares the total capital costs for pure fossil fuel, hybrid solar-fossil fuel, and solar-hydrogen systems for various PV module, fuel cell, and electrolyzer costs and alternative PV module and fuel cell efficiencies for high insolation conditions. The total capital cost C_T for the solar-hydrogen system ranges from about \$4100/kW to \$6200/kW, with PV costs dominating the total system costs. Capital costs for the pure fossil fuel system are under \$1000/kW, while capital costs for the hybrid system are \$1260–1646/kW.

Use of sun-tracking modules (with a BOS of \$100/m² instead of \$50/m²) increases the hybrid system costs by \$80–140/kW but reduces the solar-hydrogen capital costs by \$200–600/kW (resulting in a total capital cost range of about \$3800–5600/kW). It might be possible to reduce the solar-hydrogen costs by a further \$300–400/kW by running some electrolyzers or fuel cells as electrolyzers when sunshine is available and in reverse as fuel cells when the supply of solar energy is inadequate, rather than building separate fuel cell and electrolyzer modules (Erdle *et al.*, 1990; Lehman and Chamberlin, 1991), resulting in a minimum solar-hydrogen capital cost (for the assumptions used here) of about \$3500/kW. However, modules capable of running in either mode might not be optimized for either electricity or hydrogen production, so it is not known whether dualmode operation would be economical or not.

TABLE VIII

Total capital costs for pure fossil fuel (natural gas), hybrid solar-natural gas, and solar-hydrogen systems, for various PV module costs and efficiencies, assuming basic power plant costs of \$650/kW for natural gas and \$550/kW for hydrogen fuel cells (including building and power conditioning costs), and assuming the high insolation case with inclined modules. Total capital costs include 20% backup capacity, and a 25% indirect cost factor for solar components. Solar hydrogen costs in brackets are for sun-tracking PV modules

Solar module parameters		Total capital costs (\$/kW)		
Cost (\$/m ²)	Efficiency	Pure fossil	Hybrid	Solar hydrogen
40	15	780	1398	4856 (4641)
40	20	780	1260	4089 (3834)
80	15	780	1646	6218 (5564)
80	20	780	1444	5111 (4526)

The operation and maintenance cost for the solar-hydrogen system is computed as:

$$OM_{H_2} = N_1 OM_{PV} + N_2 OM_{EL} f_{EL} + N_3 OM_{FC} f_{FC} , \quad (6)$$

where OM_{EL} , OM_{PV} , and OM_{FC} are the operation and maintenance costs for electrolyzers, PV arrays, and hydrogen powered fuel cells, f_{EL} is the average electrolyzer load as a fraction of peak electrolyzer capacity, and f_{FC} is the average fuel cell load as a fraction of peak fuel cell capacity. It is assumed that $OM_{EL} = OM_{FC} = \$30\text{--}50/\text{kW DC per year}$ and $OM_{PV} = \$1.10/\text{m}^2\text{-yr}$ (as for the hybrid system). Based on iterative calculations, $f_{EL} = 0.22\text{--}0.33$ and $f_{FC} = 0.33\text{--}0.36$. The cost of solar-hydrogen electricity is given by

$$C = \frac{(CRF + INS)C_T + OM_{H_2}}{H_{yr}CP} . \quad (7)$$

Table IX compares the cost of electricity as supplied by pure fossil fuel, hybrid solar-fossil fuel, and solar-hydrogen systems for the high insolation case. Capital costs for natural gas, coal, and hydrogen fuel cell power plants of \$650/kW, \$1450/kW, and \$550/kW, respectively, are assumed. By the time the natural gas price rises to \$7/GJ, electricity from the hydrogen system will cost 0.2–5.4 cents/kWh more than from natural gas for the PV performance assumptions used here. For coal at \$2/GJ, the cost premium for the solar-hydrogen system is 1.0–4.5 cents/kWh. More importantly, the cost of solar-hydrogen electricity in regions with high insolation is not much greater than the present cost of electricity in many parts of the world, and could be partly or wholly compensated by increased end-use efficiency.

TABLE IX

Comparative costs of electricity from fossil fuel, hybrid solar-fossil fuel, and solar-hydrogen systems. Costs for NG (natural gas) are for fuel prices of \$3–7/GJ, while costs for coal are for fuel prices of \$1.5–2.5/GJ. Inclined modules and 5% interest are assumed. Hydrogen system costs given in brackets are for sun-tracking modules

Solar module:		Cost of electricity (cents per kWh)					
Cost (\$/m ²)	Efficiency	NG	Coal	PV	Solar-NG	Solar-coal	Hydrogen
40	15	3.6–6.2	4.5–5.3	4.7	4.0–5.9	5.1–5.6	8.1 (7.6)
40	20	3.6–6.2	4.5–5.3	3.7	3.8–5.7	4.9–5.4	6.8 (6.3)
80	15	3.6–6.2	4.5–5.3	6.3	4.4–6.3	5.5–6.0	10.1 (9.0)
80	20	3.6–6.2	4.5–5.3	4.9	4.1–5.9	5.2–5.7	8.4 (7.3)

5. Other Considerations and Possibilities

In this section we briefly discuss (i) land constraints; (ii) special problems associated with hydrogen transport; (iii) high temperature water vapour electrolysis as an alternative method of hydrogen production; and (iv) alternative means of providing continuous electricity from solar energy.

5.1. LAND AREA CONSTRAINTS

In densely populated regions, the availability of land will limit the fraction of electricity demand that can be met with solar energy. Land constraints will be more important in a solar-hydrogen system, in which three–four times the land area would be needed compared to a hybrid system. Both hybrid and solar-hydrogen systems are likely to be viable for large scale power production only in arid and possibly semi-arid regions. Table X gives the area and mean annual insolation of major global deserts. Assuming a total of four photovoltaic units with a peak output of about 1 kW DC per kW AC peak electricity demand (as calculated above), 15% module efficiency, and coverage of only half the area on a site with PV arrays (to avoid shading problems), only 1% of the global desert area would be needed to replace the total 1986 global electricity capacity of 2.46 TW (UN, 1988; 1 TW = 10¹² W). Nitsch and Voigt (1988) discuss the material, energy, and transport requirements associated with large scale use of solar energy and hydrogen in the world's desert regions, and conclude that these requirements can be easily met.

5.2. HYDROGEN TRANSPORT AND EMBRITTLEMENT

If solar energy is used to make hydrogen in desert regions, away from electricity demand centers, it might be preferable to transport some hydrogen to demand centres for storage and on-site electricity generation, with the by-product heat used

TABLE X

Area and incident solar radiation of the major global deserts, based on Barry and Chorley (1982)

Desert/region	Nominal area (10^6 km^2)	Annual mean insolation (W m^{-2})
North Africa	7.77	225–250
Arabian Peninsula	1.30	250–275
Australia	1.55	200–225
Kalahari	0.52	200–225
California	0.35	200–225
Thar (India)	0.26	225–250
Mexico	0.15	225–250
Total/average	11.90	about 250

for space and water heating or for industrial process heat. This would give an overall hydrogen utilization efficiency of 90–95% – comparable to the best fossil fuel-based cogeneration systems in use today.

Hydrogen can cause sudden and unpredictable decreases in the strength of certain steels – a phenomenon referred to as hydrogen embrittlement, which is implicated in a number of industrial accidents involving hydrogen. Thompson (1979) provides a thorough discussion of this problem. The problem is worse for high strength steels and at high temperatures. The areas of greatest concern thus involve compressor stations envisaged for high pressure, long distance hydrogen transport. Among the options being investigated to resolve the hydrogen embrittlement problem are the use of a gaseous inhibitor, greater use of Si, Ti, and Ni as alloying elements in steel, improved welding of pipelines, and application of internal coatings. Thompson (1979) argues that the problem can be solved, the only question being at what cost.

Carpentis (1988) discusses the energy losses and estimated costs associated with large scale hydrogen pipeline transport. Energy requirements amount to about 3% of throughput per 1000 km (based on a compressor shaft energy requirement of 1.5% of throughput and a hydrogen-to-shaft-power conversion efficiency of 50%), compared to about 7% for electricity transmission, while transmission costs are estimated at about 0.3 cents/kWh per 1000 km, which is comparable to the lowest electricity transmission costs. Although several hydrogen pipeline systems exist today, they are of small diameter (20 cm rather than the 2 m optimum in a large scale system) and low pressure (generally below 7 MPa rather than 10 MPa (100 atm) envisaged in a hydrogen economy) and use low strength steels, and therefore provide little guidance for future systems. In light of the embrittlement problem,

cost estimates are speculative, although it is possible that long distance hydrogen transport will be less costly than present electricity transport costs.

5.3. HIGH TEMPERATURE WATER VAPOUR ELECTROLYSIS

The energy required for splitting water is smaller in the vapor phase than in the liquid phase. Furthermore, as temperature increases the minimum voltage (and electrical energy) required for electrolysis decreases and the remaining energy can be provided as thermal energy. In high temperature water vapor electrolysis some of the heat produced as a byproduct of electricity generation, which would otherwise be wasted, is used to split water, thereby increasing the overall efficiency of hydrogen production.

To provide thermal energy at sufficient temperatures (750–1000 °C) as a byproduct of solar electricity generation requires solar thermal rather than PV electricity generation. In solar thermal energy systems, mirrors are used to concentrate sunlight to generate sufficient heat to create steam and drive a steam turbine. Given PV module and PV-electrolyzer coupling efficiencies of 15% and 95%, respectively, and an electrolysis efficiency of 90%, the net conversion efficiency from solar energy to hydrogen is 14% using PV electricity. Conceptual design studies suggest that the net conversion efficiency from thermal energy to hydrogen using high temperature water vapor electrolysis could be 47% (Erdle *et al.*, 1986). Given an effective solar collector efficiency of 65% (Nitsch, 1988), the net conversion efficiency from solar radiation to hydrogen would be about 30% – a factor of two improvement.

Costs for thermal solar electricity could very well be competitive with PV electricity in regions with adequate direct beam solar radiation. However, high temperature steam electrolysis is likely to be more expensive than conventional electrolysis and significant questions remain concerning the reliability of such a system (Schnurnberger *et al.*, 1988).

5.4. SOLAR THERMAL AND BIOMASS ALTERNATIVES

Solar thermal power plants are currently used to provide peak load electricity. Capital costs of solar thermal power plants have fallen rapidly, from \$20,000/kW in 1980 to \$3–4000/kW at present, and are projected to reach \$1250–2500/kW by 2005–2010 (De Laquil *et al.*, 1992). Corresponding electricity costs are \$0.12–0.17/kWh at present and \$0.045–0.12/kWh for 2005–2010. With the addition of thermal energy storage, solar thermal power plants could provide electricity 24 hours per day and meet up to 80% of total electricity load (Mills and Keepin, 1993). To do this competitively, total capital costs, including thermal storage, would have to fall to within about \$850–2000/kW of its fossil fuel competitor for fuel costs of \$3–7/GJ (assuming 5% interest rate, 0.5% yr⁻¹ insurance, a 20 year lifetime, and 55% fossil fuel utilization efficiency). Given the above price projections and the prospect of inexpensive thermal storage (Mills and Keepin, 1993), this is a distinct possibility. However, unlike PV power plants, solar thermal

power plants depend largely on direct beam solar radiation and hence would be viable only in regions with infrequent cloud cover. Nevertheless, in appropriate regions, load-following solar thermal power systems could largely eliminate the need for fossil fuels without using hydrogen as a storage medium, but possibly at much less cost than using hydrogen.

Use of biomass represents a second, indirect means of using solar energy to generate electricity. Biomass gasification coupled with combined-cycle electricity generation is relatively simple and inexpensive (Williams and Larson, 1993). However, the overall conversion efficiency of solar energy to electricity is low ($< 1\%$) due to the low efficiency of photosynthesis, so that land requirements are large.

6. Potential Negative Environmental Impacts

Although a solar hydrogen system would eliminate the need for fossil fuels in supplying electricity, a portion of any hydrogen leaking from the system would enter the stratosphere and produce water vapour, where it would serve as a potent greenhouse gas and affect stratospheric ozone.

We shall compute the warming impact of solar-hydrogen electricity as the product of the following factors:

forcing per molecule \times emission factor \times leakage to stratosphere \times lifetime

while that of fossil fuel electricity generation is computed as the product of

forcing per molecule \times emission factor \times lifetime.

The order of magnitude of each of these terms is estimated below.

Ramanathan and Coakley (1978) indicate that a doubling of stratospheric water vapour concentration would increase surface-troposphere heating by about 1.9 W m^{-2} . Assuming a stratospheric pressure thickness of 150 mb with 5 ppmv water vapour, this corresponds to a heating rate of $7.3 \times 10^{-12} \text{ W m}^{-2}/\text{kg H}$. A doubling of CO_2 causes a heating of about 4.4 W m^{-2} (Schmitt and Randall, 1991), corresponding to a heating rate of $5.9 \times 10^{-15} \text{ W m}^{-2}/\text{kg C}$ – about 3 orders of magnitude smaller.

Based on results presented in Table VII, the fraction γ of annual hydrogen production which leaks to the atmosphere for the inclined-module case is 0.37%. For a hydrogen heating value of 120.9 MJ/kg, the resultant emission factor is $2.48 \times 10^{-2} \gamma \text{ kg H}_2/\text{kWh} = 9.2 \times 10^{-5} \text{ kg H}_2/\text{kWh}$ when averaged over total annual electricity production. For the hybrid natural gas system at 55% fuel cell efficiency, the emission factor is $7.7 \times 10^{-2} \text{ kg C/kWh}$.

To estimate the fraction of emitted hydrogen which reaches the stratosphere, note that, in spite of the main sources and sinks of atmospheric hydrogen being at the earth's surface (Khalil and Rasmussen, 1990), the hydrogen mixing ratio is uniform from the surface to about 4 km above the tropopause (Schmidt, 1974). We can therefore regard the troposphere as a well mixed box which exchanges mass

and hence hydrogen with the stratosphere. Given a mean atmospheric lifespan τ_{H_2} for hydrogen of 2 years (Khalil and Rasmussen, 1990) and an average time τ_{tr} of 1.25–5 years for tropospheric mass to completely exchange with the stratosphere (Follows, 1992), the fraction of emitted hydrogen leaking to the stratosphere is given by $\tau_{\text{H}_2}/\tau_{\text{tr}}(1 - e^{-\tau_{\text{tr}}/\tau_{\text{H}_2}}) - 0.37$ to 0.74. Most estimates suggest a tropospheric mass turnover time closer to 5 years, so we shall use 0.4 as the leakage factor.

Finally, one must consider the relative lifetimes of stratospheric water vapor and atmospheric CO_2 . Given several exchanges per year of lower stratospheric mass with the troposphere (Follows, 1992) and photochemical lifetimes on the order of 1 year in the upper stratosphere (Le Texier *et al.*, 1988), the effective stratospheric water vapor lifespan is estimated to be on the order of 1 year or less (water vapor in the upper stratosphere is much less effective in surface-troposphere heating than water vapor in the lower stratosphere (Lelieveld and Crutzen, 1992), where a shorter lifetime applies). In the case of CO_2 , multiple time scales are involved (Harvey, 1993) but an appropriate mean lifespan is on the order of 100 years.

Given the above crude estimates, the greenhouse heating factors are $7.2 \times 10^{-14} \text{ } \gamma \text{ W m}^{-2}/\text{kWh}$ for a solar-hydrogen system and $4.5 \times 10^{-14} \text{ W m}^{-2}/\text{kWh}$ for a natural gas-solar hybrid system. Thus, the global warming for the hydrogen system relative to the hybrid system is equal to about twice the fractional leakage rate, and hence likely to be on the order of 1%. This result is applicable only when comparing emissions and global warming effects over a time period of 100 years or longer; at a one year time scale there would be little difference between the two.

If the total 1986 fossil fuel electricity production of 6349 TWh (UN, 1988) were supplied by solar-hydrogen with an emission factor of $9.2 \times 10^{-5} \text{ kg H}_2/\text{kWh}$, the total H_2 emission would be about 0.58 Tg yr^{-1} , with a corresponding flux into the stratosphere of about $0.23 \text{ Tg H}_2 \text{ yr}^{-1}$. Assuming a mean lifespan for stratospheric water vapor of one year, the steady water vapor increase for a continuous hydrogen flux into the stratosphere of 0.23 Tg yr^{-1} is $2.1 \text{ Tg H}_2\text{O}$, which is insignificant compared to the present stratospheric water vapour mass of 2300 Tg (assuming 5 ppmv concentration). Any impacts on stratospheric ozone are likely to be negligible. The estimated global H_2 emission of $0.6 \text{ Tg H}_2 \text{ yr}^{-1}$ is more than an order of magnitude smaller than the direct anthropogenic emission of 17 Tg yr^{-1} estimated to occur at present (Schmidt, 1974), much of it a byproduct of fossil fuel combustion. Thus, both in absolute terms and in comparison to present anthropogenic emissions, the impacts of solar-hydrogen electricity production on global warming or stratospheric ozone are likely to be very small.

7. Global Energy System Context and Carbon Taxes

As the above analysis indicates, there are a number of low to negative cost options for significantly reducing CO_2 emissions associated with electricity generation. On the other hand, complete elimination of electrical CO_2 emissions by moving to a hydrogen economy would, in the near term, entail a considerable increase in

electricity costs. As long as the low cost options discussed here have not been fully exploited in developing countries, it will be more cost-effective for industrialized countries to invest in technological improvements in developing countries than in making their own transition to a solar-hydrogen system for electricity generation. Such investments could be facilitated through a system of tradeable emission permits (Grubb, 1990), supplemented with an international carbon tax on excess emissions, which would set a cap on the market price of the permits. Given that CO₂ emissions do not have to be reduced to near zero to stabilize atmospheric CO₂ concentration (Harvey, 1989), active pursuit of least-cost methods for reducing CO₂ emissions would most likely defer the need for solar-hydrogen electricity generation to well into the next century.

In practice, individual nations may opt for a solar-hydrogen system sooner for reasons relating to regional air pollution, security or diversity of energy supply, or technological development. This is particularly the case in the transportation sector, where vigorous efforts are underway in several countries to develop hydrogen-powered road vehicles using alkaline or solid polymer fuel cells. For fuel cell-powered automobiles to be economically feasible, fuel cell costs would have to drop to on the order of \$100/kW (given a fuel cell power requirement of 20–40 kW, with batteries for peak power). Application of thin film technologies could dramatically reduce the size and material costs of fuel cells (Schock, personal communication, 1993), and fuel cells for automobiles would not need to be designed to have as long an operating life as fuel cells for electric utilities, so costs this low are conceivable. If hydrogen-fuel cell road vehicles become economically feasible, however, the implied hydrogen and fuel cell cost reductions are such that fuel cells would almost certainly be preferred to advanced gas turbines for stationary power generation, and the solar-hydrogen system cost would be even lower than projected here. For this reason, it is unlikely that hydrogen will achieve widespread use in the transportation sector without also becoming attractive for use in the electric utility sector.

Hybrid solar-natural gas systems are most attractive when the price of natural gas is high, which is the same condition which makes coal attractive relative to natural gas. Thus, as natural gas prices increase, the main competition in sunny regions where both coal and natural gas are available is likely to be between coal and natural gas, rather than between fossil fuel and hybrid solar-fossil fuel electricity generation. One means of encouraging lower CO₂ emissions, whether by fuel switching from coal to natural gas, or by deployment of solar-fossil or solar hydrogen systems, is through imposition of a carbon tax. A number of economists have attempted to estimate the magnitude of carbon tax required, at the international level, to achieve various degrees of CO₂ emission reduction (i.e.: Manne and Richels, 1992; Cline, 1992).

Table XI gives the carbon tax (\$/tonne C) required to make the cost of electricity from natural gas equal to that from coal for various natural gas and coal power plant and fuel costs, assuming a 5% interest rate. Because capital costs using

TABLE XI

Carbon tax (\$/tonne C) required to make the cost of electricity produced from natural gas equal to that produced from coal, for various natural gas and coal power plant costs and fuel costs

Natural gas		Coal at:	Coal plant @ \$1450/kW		Coal plant @ \$1650/kW	
Plant cost	Fuel cost		\$1.5/GJ	\$2.5/GJ	\$1.5/GJ	\$2.5/GJ
\$650/kW	\$3/GJ		0	0	0	0
	\$5/GJ		40	0	0	0
	\$7/GJ		198	111	154	68
\$850/kW	\$3/GJ		0	0	0	0
	\$5/GJ		83	0	40	0
	\$7/GJ		241	154	198	111

natural gas are substantially less than for coal, natural gas must cost 2–3 times that of coal before it becomes uncompetitive. Nevertheless, if natural gas reaches a cost of \$7/GJ and coal costs \$1.5/GJ, a carbon tax on the order of \$100–200/tonne would be required for natural gas to remain competitive*. Table XII gives the carbon tax required to equalize the cost of fossil fuel electricity and solar-fossil or solar-hydrogen electricity. For natural gas at \$7/GJ, the solar-fossil hybrid is competitive without a carbon tax, while at \$3/GJ, carbon taxes of \$76–281/tonne would be required to make the solar-natural gas system competitive. In the case of coal, a carbon tax of \$28–180/tonne would be needed to make the hybrid system competitive. By comparing Tables XI and XII, it can be seen that the carbon tax which makes either a solar-natural gas or solar-coal hybrid competitive with the corresponding pure fossil fuel system is sufficient to make natural gas competitive with coal, for the range of assumptions adopted here.

Finally, carbon taxes from \$111/tonne to \$660/tonne would be needed to make the solar-hydrogen system competitive with natural gas-based electricity. In the case of coal, the required carbon tax ranges from \$70/tonne to \$274/tonne. Although the upper limits are large, there are several combinations of assumptions which result in carbon taxes on the order of \$100/tonne being sufficient to make the solar-hydrogen system competitive. This in turn implies that continued research and development to achieve the performance and cost assumptions adopted here is a good investment as a hedge against the risk that very large absolute reductions of CO₂ (and CH₄) emissions will be required early in the next century.

* An exception could occur in instances where local land use regulations permit siting of natural gas power plants in dense urban centres but not coal power plants, in which case significant transmission cost savings would accrue using natural gas, thereby increasing the range of fuel cost difference over which natural gas would still be competitive.

TABLE XII

Carbon taxes (\$/tonne C) required to make the cost of electricity from the solar-fossil and solar-hydrogen systems equal to that produced from natural gas and coal for various PV module costs and efficiencies and for various fuel costs. Results are given using inclined modules for the solar-fossil system and sun-tracking modules for the solar-hydrogen system

Module cost (\$/m ²)	Module efficiency	Fuel costs:	Natural gas plant @ \$650/kW			Coal plant @ \$1450/kW	
			\$3/GJ	\$5/GJ	\$7/GJ	\$1.5/GJ	\$2.5/GJ
<i>For solar-fossil system:</i>							
40	15		155	29	0	110	72
	20		76	0	0	66	28
80	15		281	155	29	180	142
	20		170	44	0	119	81
<i>For solar-hydrogen system:</i>							
40	15		504	378	252	188	149
	20		362	236	111	109	70
80	15		660	534	408	274	236
	20		479	353	228	174	136

8. Conclusions

This paper has examined the relative costs of advanced fossil fuel electricity generation, photovoltaic-fossil fuel hybrid electricity, and solar-hydrogen electricity. Technical performance and cost assumptions appropriate to the year 2000–2010 time frame have been used throughout, with an effort made to be internally consistent in comparing the three electricity generation options. Realization of the electricity cost estimates obtained here requires significant but plausible cost and performance improvements compared to present day technology.

If projected improvements are achieved, then for low insolation conditions (160 W m⁻² mean annual solar radiation), photovoltaic electricity could cost 5–13 cents/kWh by 2000–2010, while for high insolation conditions (260 W m⁻²) the cost could be 4–9 cents/kWh (these and subsequent costs assume a 5% interest rate and include 20% backup capacity but exclude administrative and transmission costs). Advanced fossil fuel-based electricity generation should achieve electricity generation efficiencies of 45–55% using coal and 50–60% using natural gas. For capital costs of \$650–850/kW for natural gas-fuelled power plants and natural gas costs of \$3–7/GJ, electricity would cost 3.5–7 cents/kWh, while for coal plant costs of \$1450–1650/kW and coal costs of \$1.5–2.5/GJ, electricity would cost 4.5–7 cents/kWh for coal. Carbon dioxide emissions would be reduced by 1/3 without fuel switching, and by up to a factor of four if inefficient (25–28%) coal-

based electricity (common in developing countries) is replaced with highly efficient (50–60%), natural gas fired electricity.

In a solar-fossil fuel hybrid, some electricity would be supplied from solar energy whenever the sun is shining and the remaining demand satisfied by fossil fuels. This increases total capital costs but saves on fuel costs. For low insolation conditions, the cost of electricity increases by 0–2 cents/kWh, while the cost of electricity decreases in many cases for high insolation conditions. Solar energy would provide about 20% or 30% of electricity demand for the low and high insolation cases, respectively, using fixed modules inclined at the latitude angle.

In the solar-hydrogen energy system, some photovoltaic arrays would provide current electricity demand while others would be used to produce hydrogen electrolytically for storage and later use in fuel cells to generate electricity. An alternative would be to rely on solar thermal electricity generation and high temperature water vapor electrolysis for hydrogen production. For natural gas at \$7/GJ, the cost premium for a solar-hydrogen system in high insolation conditions is 0.2–5.4 cents/kWh, while for coal at \$2/GJ, the cost premium is 1.0–4.5 cents/kWh.

If a global regime for limiting greenhouse gas emissions involves tradeable emission permits, then it will be possible for high CO₂ emitting countries to invest in energy efficiency measures or renewable energy in low CO₂-emitting countries (generally third world countries) whenever this is cheaper than reducing their own emissions. Only when all cheaper emission reduction opportunities in all nations have been exhausted will there be economic pressure to begin replacing solar-fossil fuel hybrid systems with completely renewable, solar-hydrogen energy production. This could very well be delayed until the middle of the next century or later.

Efforts to reduce global CO₂ emissions might accelerate the expected long term increase in the price of natural gas, while depressing the price of coal. If the price of natural gas to utilities reaches \$7/GJ while coal remains near \$1.5/GJ, a solar-natural gas hybrid system would be cost-competitive with a pure natural gas power plant in high insolation regions, but natural gas and a solar-coal hybrid would not be competitive with coal. To make natural gas at \$7/GJ competitive with coal would require a carbon tax of about \$100–200/tonne. Such a carbon tax would simultaneously make the solar-coal hybrid power plant competitive with a pure coal power plant. The carbon tax required to make the solar-hydrogen power plant competitive with a fossil fuel power plant ranges from \$111–660/tonne for natural gas and \$70–274/tonne for coal.

Seasonal storage of hydrogen underground – which is estimated to be substantially less expensive than alternative seasonal storage options – might entail leakage to the atmosphere of about 0.5% of annual hydrogen production. Some of this hydrogen would reach the stratosphere, where it would be oxidized to water vapor and contribute to both ozone depletion and surface-troposphere heating. The global warming effect would initially be comparable to that of the solar-fossil fuel hybrid system, but would decrease to on the order of 1% of the hybrid system impact after about 100 years. Impacts on stratospheric ozone through formation of

water vapour are likely to be very small because the perturbation in stratospheric water vapor amount, assuming all current fossil fuel electricity to be produced by a solar-hydrogen system, would be very small. Indeed, total hydrogen emission from a global solar-hydrogen system for electricity generation could be substantially smaller than current emissions associated with fossil fuel use.

Most of the components needed for a solar-hydrogen system can be developed for fossil fuel-based fuel cell and hybrid solar-fossil fuel systems, which could serve as intermediate steps in the evolution to a solar-hydrogen system. Even if fuel cells are not competitive with combined cycle and IGCC power plants for large scale, centralized electricity generation, they could very well be competitive for decentralized, dispersed power generation. Hence, funding support for these technologies – particularly fuel cells and photovoltaic and solar thermal electric power generation – is justified irrespective of whether or not the current electricity system eventually evolves to a solar-hydrogen system. Evolutionary, incremental change is possible.

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Appendix One: Computation of Incident Solar Radiation

The incident solar radiation at the top of the atmosphere is given by:

$$Q(\theta, t) = \left(\frac{Q_s}{d^2} \right) \cos \theta, \quad (\text{A-1})$$

where Q_s is the solar constant (taken as 1368 W m^{-2}), d is the earth-sun distance as a fraction of the mean earth-sun distance, and θ is the solar zenith angle. The earth-sun distance d , normalized by the mean earth-sun distance, is given by (Berger, 1978):

$$d = \frac{1 - \epsilon^2}{1 + \epsilon \cos \left((\gamma - P) \frac{\pi}{180} \right)}, \quad (\text{A-2})$$

where ϵ is the orbital eccentricity (0.01672), P is the longitude of perihelion (282.04°) and γ is the orbital angle measured from the vernal equinox (21 March). $\gamma = P$ on 3 January, when the Earth is closest to the sun. The solar zenith angle θ is given by (Sellers, 1965):

$$\cos \theta = \sin \phi \sin D + \cos \phi \cos D \cos h, \quad (\text{A-3})$$

where ϕ is latitude, D is declination (the angular distance of the sun north (positive) or south (negative) of the equator), and h is the solar angle (the angle through which the earth must turn to bring the meridian under question directly under the sun). The declination is assumed to vary sinusoidally as:

$$D = \alpha \sin \left((t_y - 70) \frac{\pi}{180} \right), \quad (\text{A-5})$$

while the solar angle is given by:

$$h = (12 - t_d) \frac{15\pi}{180}, \quad (\text{A-6})$$

where t_y is time of year ($t_y = 0$ on 1 January and 360 on 31 December), t_d is time of day in hours (with $t = 12$ at solar noon), and α is orbital obliquity (equal to 23.447°). If $\cos \theta < 0$ the incident solar radiation is zero.

In the case of a surface inclined at an angle α from the horizontal with an azimuth of zero (facing due south), the angle θ^* between the surface normal and the sun is given by:

$$\cos \theta^* = \cos \alpha \cos \theta + \sin \alpha \left[\frac{\sin \phi \cos \theta - \sin D}{\cos \phi} \right], \quad (\text{A-7})$$

which can be readily derived from Sellers (1965).

The solar radiation I_T incident on an inclined plane at the earth's surface is given by:

$$I_T = I_{Dr} + I_{Df} + I_R, \quad (\text{A-8})$$

where I_{Dr} , I_{Df} , and I_R are directly transmitted, diffuse, and reflected components. These are given by:

$$I_{Dr} = \left(\frac{Q_s}{d^2} \right) (1 - O_3)(1 - A_w) D_R \cos \theta^*, \quad (\text{A-9})$$

$$I_{Df} = D^\downarrow \left\{ D_R \frac{\cos \theta^*}{\cos \theta} + 0.5(1 - D_R)(1 + \cos \alpha) \right\}, \quad (\text{A-10})$$

$$I_R = \left(\frac{Q_s}{d^2} \right) (1 - O_3)(1 - A_w) D_R \cos \theta \left\{ \frac{1}{2} \alpha_s (1 - \cos \alpha) \right\}, \quad (\text{A-11})$$

where O_3 and A_w are the fractional ozone and water vapor absorption (computed as in Harvey and Schneider, 1985), D_R is a zenith angle-dependent direct beam transmission function from Thompson and Barron (1981), α_s is the surface albedo (fixed at 0.35), and D^\downarrow is the diffuse radiation incident on a horizontal surface. Equation (A-10) is based on Hay (1986), while the factor of $0.5(1 - \cos \alpha)$ in Equation (A-11) arises by assuming the reflecting surface to be semi-infinite and the reflected radiation to be isotropic. D^\downarrow is computed here as the sum of singly and multiply scattered components D_1 and D_2 , which are given by:

$$D_1 = \left(\frac{Q_s}{d^2} \right) (1 - O_3)(1 - A_w) S_F \cos \theta, \quad (\text{A-12})$$

and

$$D_2 = \left(\frac{Q_s}{d^2} \right) (1 - O_3)(1 - A_w) \{ (D_R + S_F) \cos \theta \alpha_s \overline{S_B} / (1 - \alpha_s \overline{S_B}) \}, \quad (\text{A-13})$$

respectively. S_F is a zenith angle dependent forward scattering function, while S_B is the back scattering fraction evaluated at $\cos \theta = 0.5$, both taken from Thompson and Barron (1981).

Equations (A-2) through (A-13) are used to calculate the clear-sky incident solar radiation once every 15 minutes. For the sun-tracking case we set $\cos \theta^* = 1.0$ (that is, we set $s = \pi/2 - \theta$) when the sun is above the horizon. For both inclined and sun-tracking cases it is assumed that the fraction of the module illuminated with direct beam radiation increases from zero at sunrise or sunset to 1.0 when the sun is 20° above the horizon due to shading of modules by surrounding modules.

Appendix Two: Effective Carbon Dioxide Emission Factors

The carbon dioxide emission factors of 13.6 kg C/GJ for natural gas and 25.0 kg C/GJ for coal need to be increased to account for emissions associated with the extraction, processing, and transportation of these fuels. According to DeLuchi *et al.* (1988), a 4% markup for coal will account for energy used in extraction and transportation in the United States, and will be applied generally here. In the gas of Canadian natural gas, Wiggins (1989) estimates an energy consumption of 8% of delivered energy for gas processing and 7% of delivered energy for transmission to market. As well, emissions of CO_2 from the raw gas as it is extracted amount to about 1.4 million tonnes carbon for a total production of 3.8 billion GJ, the direct combustion of which releases 51.3 million tonnes carbon. Raw gas emissions thus add another 3% to total CO_2 emissions, giving a total markup of 18%. These markups give emission factors F_{CO_2} of 15.9 kg C/GJ for natural gas and 26.0 kg C/GJ for coal. Actual markups will vary regionally.

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