CAN NUCLEAR POWER COMPLETE IN THE HYDROGEN ECONOMY?

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Abstract

Today, hydrogen is used primarily in the petroleum and petrochemical industries. The dominant technology to produce hydrogen is steam methane reforming (SMR), which uses natural gas as both feedstock and fuel. Hydrogen could become a major carrier of energy for distributed use, such as in fuel-cell vehicles. This paper compares the cost of hydrogen production using SMR technology with the cost of nuclear-powered hydrogen generation using a modular helium reactor (MHR). Natural gas prices between $6 and $8/GJ yield hydrogen from SMR with an average production cost between $11.50 and $14.50/GJ. The MHR shows a range of hydrogen production costs around $15/GJ. Thus, the MHR might be competitive in the pipeline hydrogen market with natural gas prices above $8/GJ. But high natural gas prices make the MHR extremely competitive with respect to Combined Cycle Gas Turbines. MHRs are likely to be more profitable in electricity markets than in hydrogen markets.

Keywords: hydrogen economics, electricity economics, nuclear power economics

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Nuclear power in the hydrogen economy

Today, hydrogen is used in limited quantities, and mainly in petroleum refineries and the petrochemical industry. In the United States, for example, these uses represented 93% of hydrogen consumption in 2003. However, hydrogen is an attractive energy carrier that might play a major role in many energy systems in the long term. In the medium term, the most promising area for hydrogen might be substituting for gasoline in transportation. Hydrogen produced from non-fossil fuels might be a key option for transportation and other sectors as the prices of hydrocarbon resources soar or their consumption becomes restricted for environmental reasons [1].

The advantages of hydrogen-based energy systems will depend on the hydrogen production systems implemented. Hydrogen will be a clean, environmentally friendly and sustainable energy carrier only if its production is safe and sustainable, i.e., does not induce irreversible environmental damages or exhaust non-renewable natural resources. Nuclear-produced hydrogen offers unique characteristics in terms of environmental friendliness and energy efficiency.

The development of hydrogen-based energy systems will require building not only hydrogen production facilities and end-use devices, but also an infrastructure for the distribution of hydrogen. Such structural changes in production and use of energy will take time. This implementation lag could facilitate the penetration of nuclear energy in the hydrogen supply market. This penetration would prepare a foundation for the design and deployment of advanced nuclear energy systems (e.g., very high temperature reactors) that would be better adapted to hydrogen production than the current generation of nuclear power plants.

While nuclear energy has the potential to play a significant role in a hydrogen economy [2], there are uncertainties about when hydrogen demand will be large enough to justify deployment of nuclear plants dedicated to hydrogen production or dual-production units capable of generating electricity and producing hydrogen. Furthermore, many existing and advanced technologies will compete with nuclear energy for hydrogen production, and market competition will determine the best option.

Key issues to be addressed for assessing the future of nuclear-produced hydrogen include the size and evolution of the potential markets for hydrogen, and the economics of nuclear energy versus alternatives. This paper presents a reduced-form model of the hydrogen economy. It provides estimates of the average cost of hydrogen produced by steam methane reforming (SMR) as a function of the price of natural gas. It analyses cost estimates for electricity and pipeline hydrogen produced by an advanced nuclear energy system, the modular helium reactor (MHR) developed by General Atomics.[1] Finally, the competitiveness of the MHR in both electricity and hydrogen markets is discussed. The paper finds that for all prices of natural gas the MHR is more competitive in the electricity market than in the hydrogen market. (The models presented in the paper are applicable world-wide, but the illustrative examples developed below rely on economic data and conditions in the United States.)

1 The MHR was chosen because it has been adapted for hydrogen production and because data supporting cost calculations are publicly available. There are other high-temperature nuclear power/thermo-chemical hydrogen systems that might have more favorable economics; however these more advanced systems are early in their development and have greater uncertainties. [3]

A model of the hydrogen economy

The demand for hydrogen has been growing and will continue to grow throughout the foreseeable future, whether the "hydrogen economy" emerges or not. According to the Chemical Market Reporter [4]: "The hydrogen market is getting stronger as the refining industry gears up to meet upcoming regulatory requirements in Europe, North America and other regions. In the longer term, hydrogen consumption should grow in Europe as refineries use the gas to reduce their production of heavy fuel oil. In North America, additional hydrogen demand is expected in conjunction with the use of heavier crudes that require incremental hydrotreating and hydrocracking capacity. The increased outsourcing of hydrogen supplies and the replacement of aging hydrogen production facilities in North America are also expected to encourage growth."

There are two sectors of today's hydrogen production economy: "captive capacity" owned by downstream users of hydrogen, e.g., oil refiners, and "merchant capacity" (outsourcing), where producers compete for business.[2] Throughout this decade, demand for hydrogen should continue to grow in the merchant sector: "Although aggregate hydrogen consumption is growing 4% annually, growth in the merchant hydrogen business is significantly higher, perhaps 10%" [5]. This implies adding 3-6 M m^3/day of capacity each year.[3] Can nuclear power capture a share of this pipeline hydrogen market?

Recent U.S. federal legislation points to the possibility of generating hydrogen with nuclear power. In July 2005, the U.S. Congress passed the Energy Policy Act of 2005 (PL 109-58), which addresses nuclear hydrogen production in Sections 641-645: "The Project shall consist of the research, development, design, construction, and operation of a prototype plant, including a nuclear reactor that – (1) is based on research and development activities supported by the Generation IV Nuclear Energy Systems Initiative under section 942(d); and (2) shall be used – (A) to generate electricity; (B) to produce hydrogen; or (C) both to generate electricity and to produce hydrogen. … There is authorized to be appropriated to the Secretary for research and construction activities under this subtitle (including for transfer to the Nuclear Regulatory Commission for activities under section 644 as appropriate) – (1) $1,250,000,000 for the period of fiscal years 2006 through 2015; and (2) such sums as are necessary for each of fiscal years 2016 through 2021." (emphasis added)

To understand nuclear power in the hydrogen economy, Figure 1 represents a model of the hydrogen economy now being developed in association with the Economic Modeling Working Group (EMWG) of the Generation IV International Forum (GIF). Its primary purpose is to determine demand for central station (i.e., pipeline transmission) and distributed hydrogen (e.g., with electrolysis): (1) as crude oils become heavier; (2) as hydrogen fuel-cell vehicles compete with hybrid/internal combustion engines; and (3) as hydrogen infrastructure is built. This is the "Hydrogen Economy, Energy, Environment, and Transport" (HEEET) model.

[2] Ignoring the "cryogenic liquid" market (e.g., rocket fuel) that accounts for 7% of the merchant market, in 2003 the total U.S. merchant hydrogen gas capacity was about 1 500 M Standard Cubic Feet (SCF)/day. Most of this merchant production capacity (92%) was located in three states: Texas with 560 M SCF/day, Louisiana with 440 M SCF/day, and California with 380 M SCF/day [5,6]. Also, the Chemical Market Reporter [5] writes, *"Another 3 billion SCF per day of captive hydrogen capacity exists at 145 locations in the US."* Therefore, in 2003 the U.S. had a total capacity of about 4 500 M SCF/day, or about 127 M m^3/day.

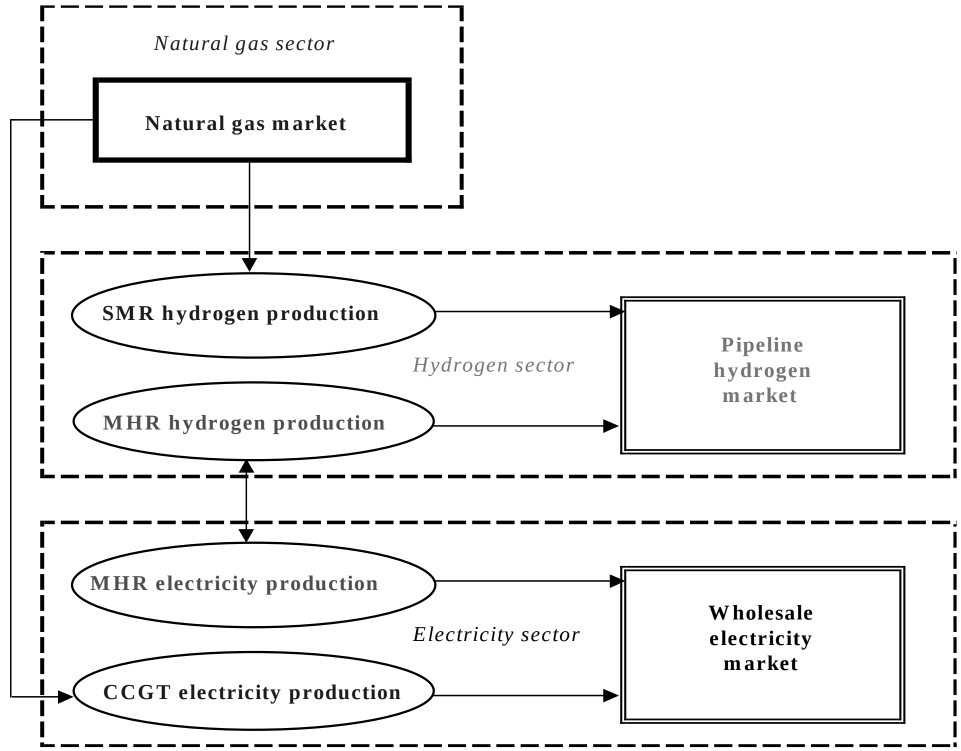
[3] Chemical Market Reporter [4] writes, *"As reported, Air Products will raise hydrogen production at its plant in Baytown, Tex, to 3 million cubic meters per day to supply ExxonMobil's nearby refinery, as well as other companies through a pipeline. Praxair Inc. has a 300-mile refinery hydrogen pipeline through Texas and Louisiana. The company expects hydrogen demand to grow by roughly 20 percent per year until at least 2012."*

In this model, energy is delivered to the hydrogen production sector through natural gas and electricity. The prices over time of natural gas and coal are econometric functions of exogenous, random oil prices. The cost of hydrogen production is described with cost-engineering models. The prices of distributed energy carriers (gasoline/diesel, electricity, and hydrogen) are determined in endogenous markets. The demand for vehicle type in the transportation sector is a function of fuel cost and vehicle investment dynamics. Our goal is to simulate probability distributions for costs, prices, and quantities of pipeline and distributed hydrogen to 2050 under various scenarios.

Figure 1. A Diagram of the hydrogen economy, energy, environment, and transport (HEEET) model

Figure 2 presents those sectors of the model discussed in this paper. These include (1) hydrogen produced with steam methane reforming (SMR) and with modular helium reactors (MHRs) and (2) electricity produced with combined-cycle gas turbines (CCGT) and with MHRs.

Figure 2. A reduced form of the HEEET Model



Average cost of hydrogen from steam methane reforming

Today most hydrogen is produced with SMR by chemically reacting natural gas and steam at high temperature [7]. SMR is described in [8] as: *"The conventional process occurs in a chemical reactor at temperatures of about 800-900∞ C. When fueled with fossil fuels it is the most economical method of producing hydrogen today [7]. The heat is generally supplied by burning an excess of the methane. This results in a loss of both the reactant, and some of the product hydrogen. Typical thermal efficiencies for steam reforming processes are about 70% [7]."*

Table 1. Costs of hydrogen produced by SMR [7]

Facility size (M Nm^3/d)	Specific total capital investment ($/GJ)	Hydrogen unit cost ($/GJ)	Reference
Small facility			
0.27	27.46	11.22	Leiby 1994
Large facilities			
1.34	14.74	7.46	Leiby 1994
2.14	12.61	6.90	Leiby 1994
2.80	9.01	6.26	Kirk-Othmer 1991
6.75	10.00	5.44	Foster-Wheeler 1996

Table 1 reproduces a summary of hydrogen production cost using SMR as compiled in [7] where the price of natural gas was assumed to be \$2.96/GJ. "Specific Total Capital Investment" (Specific TCI) is TCI divided by annual output. "Hydrogen Unit Cost" is the Levelised Unit Energy Cost. Figure 3, reproduced from [5], illustrates the cost of hydrogen production by SMR as a function of natural gas prices and facility capacity. Economies of scale are nearly exhausted at 3 M m^3/day.

Figure 3. Scale economies in SMR production of hydrogen (1998\$) [7]

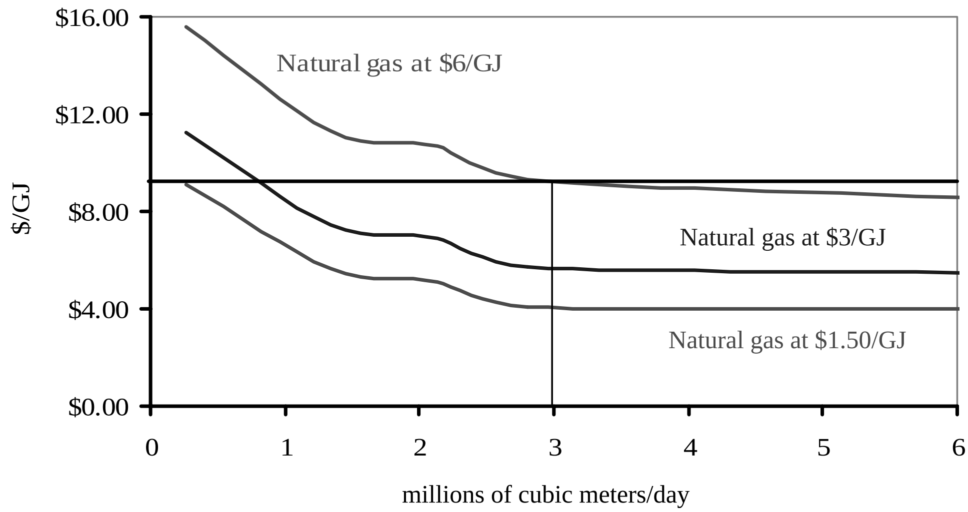


Table 2. A spreadsheet model of SMR average costs

Energy required for SMR		**Unit**
(2 steps adding to $CH_4 + 2H_2O >> CO_2 + 4H_2$)		
[1500°F or ~815°C] endothermic reaction	420	KJ/g-mole of CH_4 reactant
Moles of CH_4 to provide heat for reaction	0.495	moles at 100 % efficiency
Total moles of CH_4 to produce 4 moles of H_2	1.708	moles at 70 % efficiency
Price of natural gas feedstock	6	\$/GJ
Feedstock and fuel cost component	**9.02**	**\$/GJ H_2**
SMR plant construction cost	320	\$M
Typical large plant size (capacity)	6	M m^3/day
Annual production at 80% capacity factor	1 752	M m^3/yr
i.e.	4.8	M m^3/day
Amortise at 10.23% per year capital recovery factor	18 710	\$/M m^3 H_2
Capital cost component	**1.72**	**\$/GJ H_2**
Non-methane annual operations cost for SMR	15	\$M/yr
Non-CH_4 operations cost per unit	8 562	\$/M m^3 H_2
O&M cost component	**0.77**	**\$/GJ H_2**
Levelised unit energy cost /GJ	**11.50**	**\$/GJ H_2**
Levelised unit energy cost /kg	**1.39**	**\$/kg H_2**

Table 2 depicts a simple cost-engineering model of SMR production of hydrogen using natural gas (assuming 100% methane). Average Cost is a function of facility size and the price of natural gas. Assuming a facility of 6 M m^3 (~212 M SCF) per day, a capacity factor of 80%, a 70% thermal efficiency for SMR, and a natural gas price of \$6/GJ, the average cost of hydrogen would be about

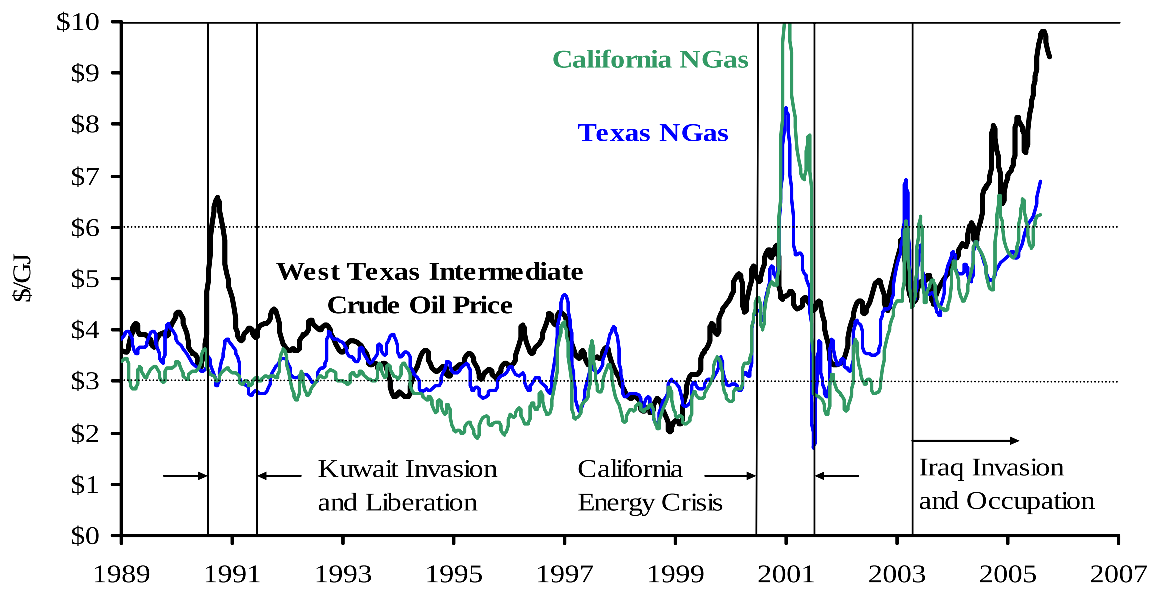
$11.55/GJ in 2001 dollars (using the U.S. GDP implicit price deflator). The relationship between the average cost of H_2 and the price of natural gas at a facility of 6 M m^3/day can be summarised as:

$$ACOST = \$2.55 + 1.50 \text{ PRICE} ,$$

where ACOST is the average cost of H_2 in $/GJ and PRICE is the price of natural gas in $/GJ (also, $1.50 = [(1.708 \text{ moles } CH_4)/(4 \text{ moles } H_2)] \cdot [(0.000849 \text{ GJ/g-mole } CH_4)/(0.000241 \text{ GJ/g-mole } H_2)]$). What is a reasonable price for natural gas?

Natural gas is sold in regional markets defined by pipeline capacity. Because of the importance of Texas and California in today's "hydrogen economy," Figure 4 presents the data for the West Texas Intermediate Crude Oil Spot Price and City Gate Natural Gas Prices in Texas and in California.[4] By applying time-series econometric techniques to these data, one can conclude that the price of oil leads natural gas prices and that the price of oil does not follow changes in any other energy price [9,10].

Figure 4. WTI Crude and Natural Gas Prices in California and Texas, 1989-2005 (2001$)



Average monthly natural gas prices since January 1, 2000, in Texas were $4.60/GJ (in 2001 dollars) with a standard deviation of $1.15/GJ, and $4.70/GJ in California with a standard deviation of $1.74/GJ. These are asymmetric distributions; for example, the mode monthly natural gas price in California was $5.52/GJ. Therefore, prices of $6-8/GJ are likely in the short run, given the price of crude oil (WTI) has averaged more than $8/GJ throughout 2005, and natural gas prices follow oil prices. With these prices, the average cost of hydrogen would be between $11.50/GJ and $14.50/GJ. At a natural gas price of $10/GJ, the average cost of hydrogen would be about $17.50/GJ. This would represent a doubling of the price of natural gas in the U.S. since 2000, would increase the price of electricity, and would have profound effects on the economy generally and on the petrochemical industry specifically.

4 Data can be found at these web sites: (1) West Texas Intermediate Crude Oil Spot Price at http://tonto.eia.doe.gov/dnav/pet/hist/rwtcM.htm (2) City Gate Natural Gas Price in Texas at http://tonto.eia.doe.gov/dnav/ng/hist/n3050tx3m.htm, and (3) City Gate Natural Gas Price in California at http://tonto.eia.doe.gov/dnav/ng/hist/n3050ca3m.htm. These prices are converted to 2001 $/GJ.

The demand for hydrogen in the petroleum and petrochemical sector should continue to grow. Although the merchant hydrogen market might not grow at 10% per year forever, new pipeline hydrogen production capacity could be fully employed in the foreseeable future as long it has an average cost of less than $15/GJ. (This ignores the cost of a hydrogen pipeline and the cost of CO_2 emissions or sequestration from SMR, which must be addressed in a more complete analysis.)

Estimating the cost of electricity and hydrogen from a Modular Helium Reactor

Estimates of the cost of producing hydrogen with the MHR have been published previously [8,11,12,13]. The cost estimates were carried out assuming that the process adopted for hydrogen production is the sulphur-iodine (S-I) technology (a technology selected after an extensive search [9, 11]). S-I is a possible technology for producing hydrogen with high-temperature nuclear heat, but has not been demonstrated at an industrial scale. S-I hydrogen production involves a multi-phase, three-step process in which water, sulphur dioxide, and iodine are reacted to release hydrogen and oxygen, while recycling iodine and sulphur dioxide by decomposing sulphuric acid. The average cost of hydrogen calculated in those studies was as low as $10/GJ.

However, estimating costs for future nuclear power technologies should adhere to a set of internationally agreed upon standards. In the following estimations, the methodology recommended by the EMWG/GIF is applied. A set of standards based on the International Atomic Energy Agency bid evaluation process has been developed by the EMWG: Cost Estimating Guidelines for Generation IV Nuclear Energy Systems. This document specifies a comprehensive set of cost estimating assumptions, such as the cost of capital and costs for each stage of the nuclear fuel cycle.[5]

Cost elements published previously [11,12,13], together with the characteristics of the MHR, have been used to estimate costs of hydrogen and electricity production by "Nth-of-a-Kind" units with the EMWG methodology. Table 3 presents the characteristics used in the EMWG spreadsheets to calculate costs for the GT-MHR producing electricity and the PH-MHR producing hydrogen; each plant is assumed to have 4 units. (The denomination PH-MHR refers to "Process Heat," because hydrogen is produced by a high-temperature thermochemical process.)

Most of the operating data for the PH-MHR are the same as for the GT-MHR. GT-MHR has a capacity of 1.145 MWe. The "electricity-equivalent" size of the 4-unit plant is adjusted to reflect the lower efficiency of the PH-MHR: a 2.400 MWth plant operating at 42% efficiency would have an electric-equivalent rating of 1.008 MWe.

The S-I hydrogen facility was optimised for a heat source of 2.857 MWth. Because the 4-module MHR produces only 2.400 MWth, the facility size and costs are reduced linearly by 16%. Fuel costs are the same for the PH-MHR and the GT-MHR, but because of the lower electric-equivalent output, fuel costs per MWh-equivalent are higher for the PH-MHR.

Regarding reactor operating costs, "Assuming the O&M costs scale as the capital cost, the O&M cost is $23,400,000 per year for the PH-MHR" [13, p. 3-37]. This cost has been converted to an all-staff equivalent of 292.5 persons at $80.000 per person per year. (This technique overestimates staff sizes, but gives a rough evaluation of whether staff sizes are reasonable.) Also, the annual chemical facility O&M costs are estimated at $48.775 M [13, Table 3-16], plus water costs of $1.805M.

5 The EMWG Guidelines, developed within the GIF framework, will be released in the near future, together with software designed for estimating the economics of Generation IV nuclear energy systems.

Table 3. Characteristics of the GT-MHR and PH-MHR

Plant characteristics		
Reactor type	GT-MHRx4	PH-MHRx4
Net thermal capacity (MWth)	2 400	2 400
Net electric capacity (MWe/MWe equivalent)	1 145	1 008
Thermodynamic efficiency (%)	47.7	42
Capacity factor of the reactor (%)	90	90
Economic life (years)	40	40
Construction duration (years) for 4 units	5	5
*Contingency rate [from EMWG *Guidelines*] (%)	15	15
*Real discount rate for IDC & amortisation	10	10
Operation and Maintenance (O&M) costs		
On-site total O&M (without chemical facility costs, $M/year)	30.11	23.40
On-site staff count (all O&M expressed in persons per year)	376.4	292.5
On-site staffing cost, including benefits ($/person)	80 000	80 000
Annual chemical facility costs ($M/year)	0	50.580
Fuel characteristics and costs		
*Enrichment level of feed (% U-235)	0.711	0.711
Enrichment plant tails assay (% U-235)	0.3	0.3
First core average enrichment level (% U-235)	15.5	15.5
Reload average enrichment level (% U-235)	15.5	15.5
Fuel elements in full core (number)	1 020	1 020
Fuel elements per reload (number)	510	510
Average time between refuelling (years)	1.5	1.5
*Cost of uranium ore ($/lb)	12	12
*Cost of uranium ore ($/kg)	31.2	31.2
*Cost of conversion from U_3O_8 to UF_6 ($/kgU)	6	6
*Cost of enrichment ($/SWU)	100	100
Cost of fuel fabrication ($/kgHM) (implied from total fuel cost)	5 756	5 756
*Cost of once-through waste disposal ($/MWh)	1	1

** Data from the EMWG Guidelines*

Table 4 presents the direct construction costs for the two plants. Equipment costs must be adjusted to account for hydrogen production: these costs include the intermediate heat exchanger ($56 M), reactor-process piping ($38 M), primary helium circulator ($33 M), and intermediate loop circulator ($22 M) (for a total of $149 M). These costs are added to Account 22. On the other hand, 84% of the “Fixed Capital Investment” of the S-I hydrogen production facility ($571.531M x 0.84 = $480 M) in account 23’ (Chemical Facility) replaces account 23 (Turbine-Generator). Also, the initial chemical inventory (primarily iodine) is equal to $114.8 M x 0.84 = $96 M. (Although there is an implicit assumption in [13] that all iodine is recycled, this assumption is challenged in [14].)

Table 4. Direct construction cost for 4-unit GT-MHR and PH-MHR (M$) [13]

Account		GT-MHR	PH-MHR
21	Buildings, structures & improvements on site	132	132
22	Reactor plant equipment & HX equipment	443	403
23	Turbine-Generator	91	–
23’	Chemical Facility	–	480
24	Electrical equipment	62	50
25	Water intake and heat rejection plant	33	–
26	Miscellaneous plant equipment	28	28
27	Special materials (including chemicals)	–	96
20	**Capitalised direct costs**	**790**	**1 190**

Adjustments made, compared to previous studies, include (1) contingency rate, (2) discount rate, and (3) decontamination and decommissioning (D&D) costs. Table 5 shows the total capital costs for both plants, highlighting adjustments made. First, the contingency rate is increased to 15% and applied to both the reactor and chemical facility.[6] Given that the S-I process has not been proven at an industrial scale, a 15% contingency is less than what EPRI Technology Assessment Guidelines would suggest. (The contingency could be doubled to 30% given the state of S-I technology; see discussion in [15].) Second, the real amortisation and IDC rate is increased to 10% and applied to all initial capital costs, including the chemical facility, initial chemical inventory, and first fuel core. (Replacement fuel is levelized over the economic life of the plant.) Third, the D&D costs were estimated at $263 M and $204 M respectively for GT-MHR and PH-MHR for 4 units, following the EMWG Guidelines (assuming the S-I facility does not require decontamination).

Table 5. Nth-of-a-Kind total construction cost for 4-unit GT-MHR and PH-MHR (M$)

Account	GT-MHR	GT-MHR adjusted	PH-MHR	PH-MHR adjusted
Capitalised Direct Costs (Account 20)	790	790	1 190	1 190
Indirects, Owners' costs (Accounts 30,40)	275	275	214	214
First Fuel Load (Account 56)	180	180	180	180
Total Contingency (Accounts 29,39,49,59)	**53**	**187**	**41**	**237**
Contingency Rate	***4%***	***15%***	***3%***	***15%***
Interest During Construction (Account 62)	**129**	**345**	**167**	**439**
5 years for 4 units, real IDC rate = 10%				
D&D costs (from EMWG *Guidelines*)	**0**	**263**	**0**	**204**
Total Capitalised Cost plus first fuel load	1 426	1 775	1 792	2 260
Specific Capital Cost for 4-unit plant (**$/kWe**)	1 245	1 550	1 777	2 242

6 Although contingency appears to have been added to the “Fixed Capital Investment” in [13, Table 13-3] under the item “Contingency” *and* Fee, the contingency and fee are equal to 18% of the “Total Bare Module Cost with Adders”. This is nearly equal to the indirect rate (“Fee”) for reactor construction (17.3%). Therefore, contingency could be as low as 0.7%, if indirect costs for the chemical facility are equal to those for the reactor.

Table 6 presents the results of the levelised cost calculations for a 40-year economic life. The annual production of 201.982 tonnes of hydrogen per year (6.2 M m^3/day) is from [13, Table 3-16]. The cost of hydrogen is $12.58/GJ under the assumptions in [13], with a Capital Recovery Factor (CRF) of 10.5%. With the cost of the first fuel core and a real CRF of 10.23%, the cost is $15.11/GJ (see last column, last line in Table 6).

Table 6. Levelised Cost for General Atomics 4-unit MHR

	GT-MHR	GT-MHR adjusted	PH-MHR*	PH-MHR* adjusted
Capital Recovery Factor	10.50%	10.23%	10.50%	10.23%
Capital Cost ($/MWh)	16.15	20.10	21.29	29.08
Fuel Cycle Cost ($/MWh)	7.40	7.40	8.27	8.27
O&M Cost ($/MWh)	3.34	3.34	9.31	9.31
D&D Cost ($/MWh)	0.00	0.07	0.00	0.06
Cost of electricity ($/MWh)	**26.89**	**30.91**		
Cost of H2 ($/kg)			**1.53**	**1.84**
Cost of H2 ($/GJ)			**12.58**	**15.11**

* *The PH-MHR cost ($/MWh) is expressed in MWh equivalence*

With the EMWG Guidelines' adjustments, the cost of hydrogen increases to $15.11/GJ, which in [13] is between the values of $13.90/GJ for a CRF of 12.5% and $16.50/GJ for a CRF of 16.5%. A reasonable range of a state-of-the-art MHR with the S-I technology is $12-$16/GJ. Therefore, the PH-MHR might be able to compete in the pipeline hydrogen market with high natural gas prices. The next section calculates whether the GT-MHR or PH-MHR would be more competitive in their respective markets.

Cost comparison of GT-MR versus PH-MHR as function of the price of natural gas

As can be seen from Table 6, the projected cost of electricity for the GT-MHR is about $31/MWh. This cost can be compared to the projected cost of electricity from an "Advanced Combustion Turbine" (Combined Cycle Gas Turbine, CCGT) [16, Table 38]. (The analysis in this section follows [17].)

The levelised unit electricity cost for CCGT using natural gas can be calculated following [18]. The USDOE-EIA Annual Energy Outlook 2005 [16] assumes an overnight construction cost of $374/kWe (including a contingency of 5%) and a construction time of two years. With a real discount rate of 10% (i.e., a 10.23% CFR), a capacity factor of 80%, and a plant economic life of 40 years, the levelised capital cost is $6/MWh. With variable O&M costs of $2.80/MWh, fixed O&M costs of $9.31/kWe, and an 80% capacity factor, O&M costs are $4.13/MWh. Finally, with a heat rate of 8.550 Btu/kWh and a natural gas price of $6/GJ (as assumed above), the levelised fuel costs are $54.38/MWh. Without including dismantling or salvage value of the CCGT, the average levelized cost is about $64.50/MWh, as shown in Table 7. (This is an average cost; it does not necessarily represent wholesale market prices; and it does not include transmission and distribution charges.)

Table 7. Levelised Cost for MHR, SMR, and CCGT with \$6/GJ natural gas

	Gas	Nuclear		△[Gas-Nuclear]
	CCGT & SMR	GT-MHR adjusted	PH-MHR adjusted	
CCGT				
Capital Cost (\$/MWh)	6.00	20.10	29.08	
Fuel Cycle Cost (\$/MWh)	54.38	7.40	8.27	
O&M Cost (\$/MWh)	4.13	3.34	9.31	
D&D Cost (\$/MWh)	0.00	0.07	0.06	
Levelised electricity cost (\$/MWh)	**64.51**	**30.91**		**+ 33.60**
SMR				
Levelised H_2 cost (\$/kg)	1.41		1.84	- 0.43
Levelised H_2 cost (\$/GJ)	**11.55**		**15.11**	**- 3.56**

In Table 7 the difference between the average cost of electricity for the GT-MHR and the CCGT is about \$33.60/MWh. If the CCGT sets the price of electricity, much of this cost difference represents profit potential to the GT-MHR owner. With an annual output of about 9,000 GWh per year, this represents a cost difference of about \$300 M per year. On the other hand, at \$6/GJ for natural gas, the cost of producing hydrogen with the PH-MHR is higher by \$3.56/GJ than the cost of producing hydrogen with SMR. (A carbon emission fee could be this high, allowing PH-MHR technology to compete with SMR.[7] Further, at all positive values for the price of natural gas, the GT-MHR is more competitive than the PH-MHR. (This does not examine the carbon savings of each technology.)

Concluding Remarks

The market potential for nuclear technology grows as the price of natural gas rises following the increasing price of oil. World energy markets are calling for new energy sources faster than anyone imagined one year ago: who then would have forecast \$65 per barrel for crude oil in mid-2005? In addition, many countries are implementing or considering policy measures to address global climate change. This enhances the attractiveness of carbon-free options, such as nuclear energy.

Any economic analysis today comparing nuclear energy versus fossil fuels must be revisited if and when carbon values are added to the cost of technologies emitting greenhouse gases. However, the comparisons presented in the paper highlight significant differences between the competitiveness of nuclear energy for generating electricity and for producing hydrogen by thermochemical processes.

[7] Future research will determine how carbon dioxide emission charges will influence both (1) hydrogen production using natural gas and SMR, and (2) electricity production using natural gas with CCGT. Other research will investigate how the cost of low and high temperature electrolysis and the cost of hydrogen storage, transmission, and distribution will influence the competitive balance between the GT-MHR and the PH-MHR.

Within the limitations of the analysis, this paper's calculations show that advanced nuclear energy systems are more likely to compete successfully in electricity markets than in hypothetical hydrogen markets. This finding is not surprising, recognising that the nuclear industry benefits from several decades of industrial experience and learning with nuclear power plants dedicated to electricity generation (and with direct-cycle turbine-generator technologies), while nuclear hydrogen production is at an early stage of technology preparedness.

Given the limited resources to develop new nuclear energy systems and given lead times and investments necessary to implement the hydrogen transmission and distribution infrastructure, the analysis here suggests that it might be wise to emphasise the design and development of advanced nuclear systems aimed at minimising the cost of electricity with commercial potential within one decade, i.e., to invest in the development of "Generation III+" technologies.

Research on high-temperature thermochemical hydrogen production techniques and very high temperature reactors should continue, while policy measures to encourage the implementation of hydrogen infrastructure would progressively lead to the development of hydrogen distribution networks, hydrogen end-use devices (e.g., fuel-cell vehicles), and the "hydrogen economy."

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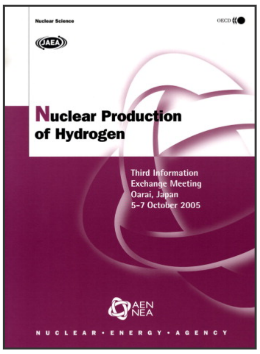

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