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Use of Nuclear Energy in Production of Synthetic Natural Gas and Hydrogen from Coal

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The integration of heat from a high-temperature nuclear reactor into coal gasification is evaluated. It is shown that if such reactors become available, it is preferable to use their energy for electricity generation and generate hydrogen electrolytically. This hydrogen can be used in coal gasification and in synthetic fuel processes. Use of nuclear energy in coal gasification is, at present, more expensive than use of coal and is only justified if coal becomes more expensive. If it is desired to use nuclear energy to save coal in coal gasification, electrolytic hydrogen presents an inherently cheaper and thermally more efficient approach as compared to direct use of nuclear heat. The paper should also be of interest to those engaged in economic evaluation of new processes as it presents a novel method of process comparison.

1. Introduction

Use of nuclear energy in the production of synthetic fuels from coal has received a varying amount of attention in recent years. It can be attractive for the long-range future as it will allow the stretching of coal reserves. There are several ways in which nuclear energy can be used in the production of synthetic fuels from coal: (a) electricity and steam generated by nuclear reactor to replace a coal fired boiler in a power plant; (b) electricity from a nuclear reactor to generate hydrogen via electrolysis; (c) a high-temperature nuclear reactor (HTGR) to supply process heat.

The use of electricity is an available and economic option today, but the main limitation is the availability of nuclear-generated electricity. The use of steam, generated by nuclear heat, is a more difficult problem since the nuclear reactor has to be physically close to the steam user, and it involves potential problems of contamination and safety. However, the amount of steam and electricity that can be used in most synthetic fuel plants to save coal input is limited to less than 20%. The process normally has large amounts of waste heat generated which has to be effectively utilized.

Generation of hydrogen, using nuclear generated electricity, is not economical at the present cost of coal, but it can be attractive in the long run, as it can replace a large fraction of the coal input needed (60–70%). In fact, almost all presently known petroleum fuels and chemicals can be generated from only hydrogen and CO_2, without a need for fossil fuels.

The third option (of using nuclear heat to supply process heat) receives probably the most attention in the limited research effort that exists in this field, mainly in Europe (Kugeler, 1980). This evaluation focuses on one specific process, namely, production of hydrogen by reforming methane using high-temperature nuclear heat. Actually, the most advanced process presently under consideration (Kugeler, 1980) is the production of synthetic natural gas (SNG) from coal by use of nuclear heat. An overall flow sheet of this process is given in Figure 1. Coal is here gasified in a hydrogasifier with hydrogen to give SNG. Part of the methane formed is reformed in a catalytic steam reformer with steam and the heat of reaction of this highly endothermic reaction, as well as the steam, is supplied from a high-temperature nuclear reactor. The gas is shifted and CO_2 is removed, and the hydrogen is then recycled to the hydrogasifier.

Table I. Overall Reactions for Three Schemes in Production of Hydrogen

coal-to-hydrogen:

$$0.435CH_{0.8}O_{0.1} + 0.826H_2O(l) \rightarrow 0.435CO_2 + H_2 \quad (1)$$

$$\Delta H^\circ_{298} = 16.82 \text{ kcal}; \quad \Delta G^\circ_{298} = 5.55 \text{ kcal}$$

nuclear steam reforming:

same as coal-to-hydrogen

water electrolysis:

$$H_2O(l) \rightarrow H_2 + 0.5O_2 \quad (2)$$

$$\Delta H^\circ_{298} = 68.3 \text{ kcal}; \quad \Delta G^\circ_{298} = 56.7 \text{ kcal}$$

In Figure 2 we present a modified flow sheet that is completely equivalent to the flow sheet in Figure 1. In it we have conceptually divided the hydrogasifier into two parts, one supplying the net methane produced and one supplying the methane for the steam reformer. The hydrogasifier supplying the net methane can receive its hydrogen from other sources and we chose here two alternatives. The same nuclear reactor can be used to generate electricity for an electrolysis plant which generates hydrogen. Alternatively, the hydrogen can be supplied from a conventional coal-fed hydrogen plant (see Figure 3).

We can, therefore, limit our comparison to the hydrogen part of the process in Figure 2, as the hydrogasifier in this comparison is equal in all schemes. If the hypothetical hydrogen process in Figure 2 has no advantage over the other two cases, the process in Figure 1 also has no advantage. The overall process in Figure 1 is at present under development in West Germany (Kugeler, 1980) but a similar scheme was proposed by Stone and Webster (1972).

This scheme was chosen for the comparison, as it is probably the most advanced of its class and is claimed to be the most promising. It is also a very illuminating case for understanding the potential role of nuclear energy in coal gasification. The overall reactions of the three schemes are given in Table I.

In a previous paper (Shinnar et al., 1981) it was shown that if it is desired to use nuclear energy to generate hydrogen, electrolysis of water has an inherent advantage over the use of nuclear heat in a thermochemical cycle. In this paper we will show that electrolytic hydrogen also has inherent advantages over the direct use of nuclear energy in coal gasification.

2. Method and Scope of Evaluation

The approach to the economic evaluation has been discussed in detail in two previous publications (Shinnar,

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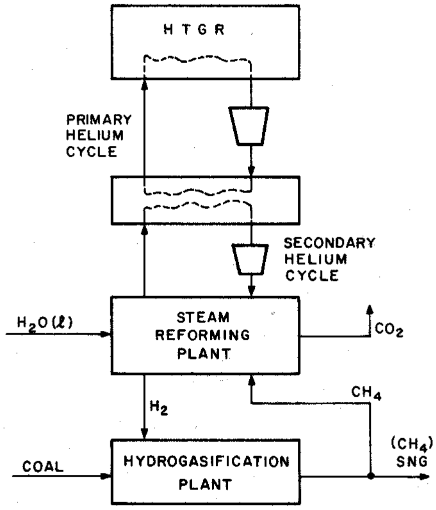

Figure 1. Schematic diagram of SNG production from coal using nuclear heat.

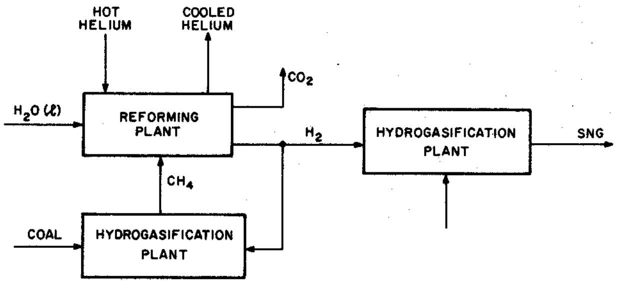

Figure 2. Modified flow sheet of the process in Figure 1. The hydrogasified is conceptually divided into two parts, one supplying the net methane produced and one supplying the methane for the steam reformer.

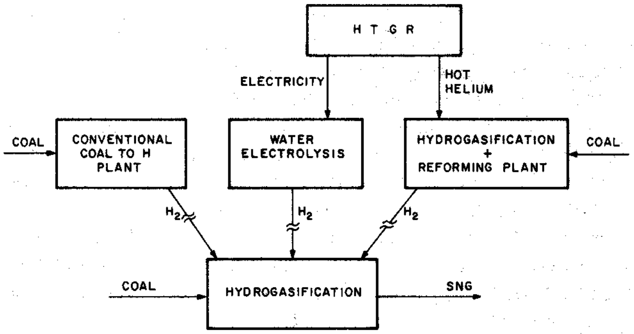

Figure 3. Three alternative routes for the production of hydrogen using nuclear heat.

1978; Shinnar et al., 1981). Instead of preparing conventional flow sheets and cost estimates, the method focuses on evaluating the inherent advantanges of the proposed technology and tries to quantify directly any potential advantage over existing technology. This proper choice of a comparison case is essential here. In our case the comparison with using electrolytic hydrogen (electrolysis of water), generating the electricity from the same nuclear reactor, is almost obvious. As both are alternatives to generating hydrogen from coal (or SNG from coal), the hydrogen from coal process is also included. Therefore, the comparison will focus on comparing the hydrogen product part of the process in Figure 2 with (1) H_2 from coal and (2) H_2 from electrolysis using electricity generated in a nuclear reactor.

For convenience, we will call the hydrogen process in Figure 2, which is the basis of our evaluation, the nuclear steam reforming route. It includes the hydrogasifier required for the hydrogen production as well as the shift and the CO_2 removal process.

The comparison is focused on hydrogen production, despite the fact that the proposed processes for using heat from an HTGR are intended for synthetic natural gas (SNG). The hydrogen from the two alternative processes can be used to produce SNG in an identical hydrogasifier (see Figure 3). Since the hydrogasification step is shared by all these processes, it can be eliminatd from the comparison. If possible, elimination of identical steps is always advisable in this type of process comparison.

An important decision regarding the two alternative base cases has to be made. Should the numbers used be based on commercially available technology or on advanced technology from bench scale or pilot plant data? If a new process can be commercialized in a short time, commercially available technology is an important base case since it is not certain that the competing advanced technologies will really be commercialized. This analysis does not deal with a near future technology, but with a process that involves a long-range government sponsored research effort. The goal here is to evaluate which technologies are more promising. Therefore, advanced technology demonstrated in pilot plants is the proper choice, but we will use both.

The only parts of the processes under comparison, for which no reliable data are available, are (a) the hydrogasifier, (b) the high temperature nuclear reactor (HTGR), and (c) the reformer heated with nuclear heat. However, it will be shown that the conclusions are not affected by their uncertainties.

There is a considerable amount of literature regarding the HTGR, and a reasonably large demonstration plant for electricity generation has been operated. However, it is difficult to obtain reliable cost estimates on a comparative basis with either conventional nuclear energy or synfuel technology. It will be assumed that the cost of an HTGR is at least competitive with conventional nuclear energy for electricity generation, and if it is cheaper, the advantage will apply equally well to the generation of electricity as well as to the supply of nuclear heat.

The reason for using two base cases is as follows: none of the two routes involving nuclear energy is competitive at present. Therefore, they have to be compared with a case based on coal only. They will only become competitive if the price of coal rises significantly. In the latter case, electrolysis provides an alternative that has some a priori advantages over the use of nuclear heat.

(a) Electrolysis is more flexible and can use a variety of nonfossil electricity sources.

(b) Electrolysis can replace a larger fraction of the coal. If we look at most coal conversion processes such as SNG, or coal liquefaction, the stoichiometry is such that if we only supply heat or steam and electricity to the process, the final product has an available free energy either lower or at best equal to the coal fed to the process. We pay this energy to convert coal to a clean convenient fuel. We do not increase the energy supply of society. On the other hand, the use of hydrogen from electrolysis in coal conversion results in a significant increase of the energy supply of our society, without changing the form of the energy to which we are accustomed.

(c) Electrolysis has a significant advantage in terms of safety and scale. The nuclear reactor can be far away from the electrolysis plant, and its scale is not limited by the process energy requirements since electricity is a salable transportable commodity. The safety problems will probably significiantly increase the cost of a plant using

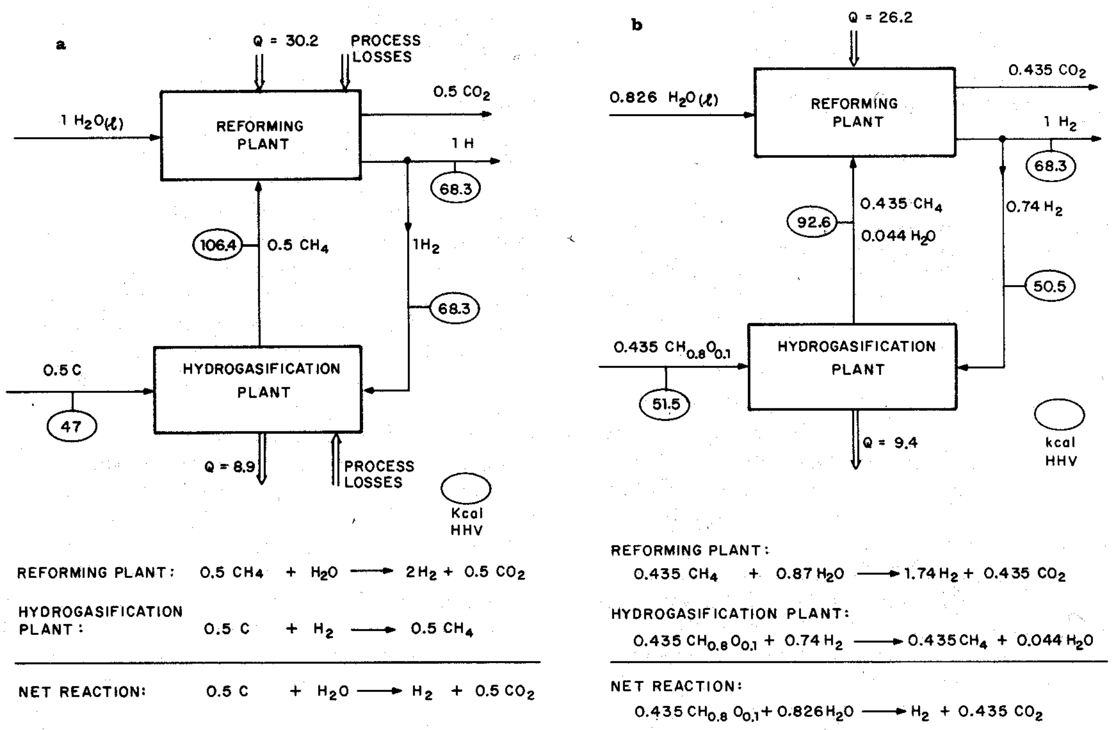

Figure 4. Stoichiometric balance for steam reforming route: (a) carbon feed; (b) eastern coal feed.

heat from the nuclear reactor (Kugeler, 1980; Shinnar et al., 1981).

In order for the steam reforming case to be attractive, compared to electrolysis, it must have very significant advantages in terms of cost to justify the development and the incremental safety risks. It will be shown that no such advantages exist, even if optimistic assumptions are made about the new technology.

It is often assumed that economic evaluation should be postponed until good process data are available. A good analysis of the problem can often show that a new route is inherently nonattractive compared to presently available technology, and the following analysis provides a good example.

3. Preliminary Analysis

Before performing a detailed economic evaluation for a completely new process, it is always advisable to do a rough estimate. In order to be able to focus on the important features of the process, it is recommended to try to understand its goals. In this evaluation the product is identical for all the schemes. The two possible goals for the new process are therefore: (1) cheaper investment cost and (2) replacing coal with nuclear energy.

The process in Figure 2, including the nuclear reactor, will require a larger investment than a conventional hydrogen plant. The steam reforming route in Figure 2 contains a steam reformer that is similar in its design to a conventional steam reformer, and its cost should also be similar. However, its size is much larger. In Figure 4, a simplified mass and energy balance for the nuclear steam reforming process is given, using carbon (4a) or coal (4b) as a feed. The mass balance is based on 1 g-mol of hydrogen. It is noted that for the carbon case, half the hydrogen produced in the steam reforming section has to be recycled to generate the total hydrogen required. Therefore, a steam reformer, twice as big as the one in a standard steam reforming plant from methane, is required to produce one net unit of hydrogen. This is an inherent disadvantage of this type of scheme resulting from the stoichiometry. For coal, the disadvantage slightly decreases (see Figure 4b), but for this analysis, a factor of 2 is a satisfactory rough estimate.

Table II. Investment for Various Processes 1980 dollars per Million Btu Daily Capacity (LHV)

process	investment
H_2 from methane	2000
H_2 from coal	6000
SNG from water and coal	5500–6500
electrolysis of water	2500–4000
HTGR	4500

Most of the elements of the hydrogen process in Figure 1 are almost identical with well-known processes. Therefore, a rough estimate of their cost can be achieved by looking at the cost of comparable industrial processes (Shinnar, 1978; Shinnar et al., 1981). A summary of cost estimates for various processes is given by Corneil (1977). Adjusted figures for 1980 dollars are repeated in Table II. The numbers in Table II are based on the production of 1 MMBTU H_2/day in a large plant. Table II shows that a hydrogen plant from coal costs about three times as much as a hydrogen plant from methane. The steam reforming scheme (Figure 4) needs the equivalent of two hydrogen plants from methane in order to obtain similar hydrogen output as one coal-to-H_2 plant. Therefore, the cost of one hydrogen plant from methane is left to allow for the cost of the hydrogasification complex.

It is unlikely that the large hydrogasification complex required will be cheaper than one steam reforming plant, but even then the overall savings will be negligible. Therefore, the nonnuclear part of the proposed process (Figure 2) will require approximately the same investment as a conventional coal-to-H_2 plant. The overall plant will therefore be much more expensive than a coal-to-H_2 plant. What is then left is goal no. 2, the saving of coal which can be achieved by both the steam reforming route as well as electrolysis. Electrolysis has the advantage of a larger potential savings of coal since all the hydrogen is produced with no use of coal.

As the overall plant, including the nuclear reactor, is much more expensive in the steam reforming route as

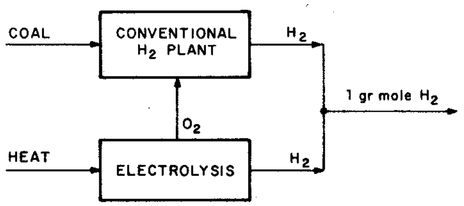

Figure 5. Conceptual combined process for production of hydrogen. Part of the H_2 is made by water electrolysis and part by conventional coal gasification. Oxygen from the electrolysis is supplied to the coal gasficiation plant. This conceptual process gives a comparison case for the case of nuclear energy by electrolysis of water that has the same coal input as steam reforming.

compared to to the coal case, such a process could only be attractive if coal becomes expensive. We invest more but are able to save coal. The same argument applies also to the electrolysis route. The overall investment will also be larger compared to a coal-to-H_2 plant. This simplifies our analysis considerably. If we compare nuclear steam reforming to a conventional coal-to-H_2 plant, we would need accurate estimates of the investment itself to estimate at which cost of coal such a process might become attractive. This is rather difficult. However, if we compare the proposed steam reforming route to electrolysis, this difficulty disappears. In both cases we pay for an incremental investment to save coal. As operating expenses are also estimated based on investment, all we have to do is to compare the relative investment for the two alternatives, and as our only possible goal is to save coal, we have to base our comparison on the basis of a unit of coal saved.

A potential advantage in the investment cost for the nuclear steam reforming route could be either to (a) a lower cost of the nuclear reactor due to a smaller size or (b) a cheaper investment for the steam reforming process compared to the electrolysis plant itself.

A detailed cost comparison will be given at the end of the paper. In our preliminary analysis all we are looking for is where to put the emphasis. If we look at Table II, it is clear that nuclear steam reforming has no advantage over electrolysis in item (b). Electrolysis of water requires a significantly cheaper investment than H_2 from coal. Using the arguments given in the beginning of this section, this means that it is also cheaper than the overall steam reforming process.

The steam reforming route also saves the generation of electricity. It was already shown by Shinnar et al. (1981) that this is not a significant item. The incremental investment to electricity generation in a nuclear plant is only a small fraction of the overall cost. If we include it in the cost of the electrolysis plant, it will still be cheaper than the steam reforming route. This will be discussed later.

Any advantage must, therefore, come from the first item, the size of the nuclear reactor. We have to be careful here. If we look at Figure 3 and base our comparison on the same amount of H_2, it is obvious that electrolysis requires a bigger reactor. But we also save more coal. A more justified comparison is therefore the flow sheet in Figure 5, where we introduce hydrogen from electrolysis into an SNG plant by replacing only a fraction of the hydrogen from coal with electrolytic hydrogen. The fraction replaced is chosen such that overall coal consumption of the combined processes is exactly the same as in the nuclear steam reforming process. We ask here, how much nuclear energy could the nuclear steam reforming route save? Therefore, the focal problem of the analysis is whether the HTGR reforming scheme replaces coal more efficiently than electrolysis. The accompanying question is, what magnitude of advantage is one looking for? This determines the accuracy of the estimates required. This is a management decision which depends on the size of the future market, on the expense involved in development, and on many other factors. If we deal with reasonably small, clearly identifiable process modification, a 5% advantage would be sufficient. In our case we deal with an expensive and totally different technology. A 10% advantage would be hard to even estimate. Furthermore, we deal with a route which has severe safety problems. In Shinnar et al. (1981) we used as a criterion a 20% overall savings in investment, which in our case would require a saving of at least 30% in the nuclear reactor section, as there is no potential for savings in the rest of the plant. This is just to give a framework to our analysis as we will later show that there is no advantage at all. If there would be any advantage, this item should receive serious attention since one can also ask for a much larger advantage to compensate for the safety problems of the HTGR-reforming scheme.

Our main question is, therefore, what is the chance that the size of the nuclear reactor required to save one unit of coal in the reforming route is 30% smaller than the one for electrolysis? To evaluate this it is required to understand the constraints which determine thermal efficiency in both routes. This will be discussed in the next section.

4. Comparison of Thermal Efficiency with Electrolysis and Steam Reforming from an HTGR

We noted before that a main parameter in the comparison is the size of the nuclear reactor required for a given unit of coal saved. This really is a different criterion than the conventional thermal efficiency of the overall plant. For electrolysis we can straightforward compute a thermal efficiency based on

$$\eta = \text{LHV of hydrogen/total heat input from nuclear reactor} \quad (1)$$

η for the electrolysis route using an HTGR can be estimated to be about 39%. The overall efficiency of a typical high-temperature gas reactor with a helium topping cycle and a steam bottoming cycle has been reported to be between 46 to 47%. The best pilot plant results for electrolysis give an efficiency of 85% (Nuttel, 1977) (in terms of utilization of electricity in generating the free energy of the water decomposition reaction).

We could also compute an overall efficiency for the steam reforming process as

$$\eta = \text{LHV of hydrogen/LHV of coal + total heat input from nuclear reactor} \quad (2)$$

However, it is very hard to compare the efficiencies computed by eq 1 and 2. It makes little sense to directly compare kcal (coal) to the kcal generated from a high-temperature nuclear reactor.

Another commonly used criterion is an efficiency coefficient in terms of free energy.

$$\epsilon_{\Delta G} = \frac{\Delta G^\circ{}_{298} \text{ of process}}{\text{available energy of heat inputs}} \quad (3)$$

For electrolysis this becomes

$$\epsilon_{\Delta G} = \frac{\Delta G^\circ{}_{298}(\text{electrolysis})}{Q\left(1 - \dfrac{T_0}{T_R}\right)} \quad (4)$$

where T_0 is the temperature of the environment, T_R is the temperature of the nuclear reactor, and Q is the total heat

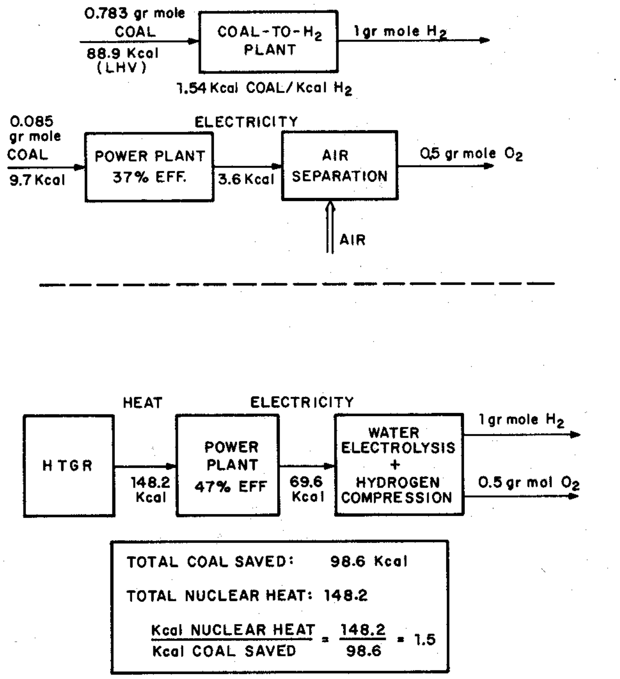

Figure 6. Energy requirements of electrolysis vs. conventional coal-to-H_2 plant.

input to the power plant generating the electricity for electrolysis. For electrolysis

$$\epsilon_{\Delta G} = \frac{56.7}{148.2\left(1 - \dfrac{530}{2160}\right)} = 0.5 \qquad (5)$$

In eq 5 we assumed that $T_R = 1700$ °F. As the free energy in the nuclear steam reforming route is totally supplied by the nuclear reactor, this could be a more justified way of comparison. However, $\epsilon_{\Delta G}$ for steam reforming is very low, as we will show later. Theoretically, the overall reaction (see Table I) limits it to below 0.44, but in practice it is less than 0.15. In general, $\epsilon_{\Delta G}$ is not very useful for processes with low increases in free energy. It is meaningless for processes for which ΔG is negative and which still require outside energy input, as for example, the overall process of SNG from coal.

There is no way in which the steam reforming route could compete with electrolysis if efficiency is measured by eq 3. Furthermore, the free energy increase of the overall process (eq 1 in Table I) is less than 10% of the heating value of the hydrogen. This just illustrates the inherent advantage of electrolysis mentioned before, namely that electrolysis using power from an HTGR increases the free energy available to society as conventional fuel, whereas the steam reforming route just changes coal to a more convenient form.

We can also look at efficiency in the context mentioned in the previous section, namely, what is the nuclear energy required to save a given amount of coal (or fossil fuel)?

We need in practive about 1.54 kcal of coal to generate 1 kcal of H_2 (LHV) or 88.9 kcal coal to generate 1 gmol of H_2 (see Figure 6). The steam reforming route requires less coal and we can therefore compute a relative efficiency as

$$E(\text{saving coal}) = \frac{\text{LHV(coal saved)/g-mol of } H_2}{Q(\text{nuclear reactor})} \qquad (6)$$

For electrolysis the coal saved is the total coal feed to a conventional coal to hydrogen plant.

If we use electrolysis we require 148.2 kcal to save 88.9 kcal of coal or 1.67 kcal/kcal of coal saved. We could now ask the question, does the nuclear steam reforming route require more or less nuclear heat per kcal of coal saved, and make this the basis of our comparison. We will use as a yardstick 148.2 kcal/g-mol, which gives

$$E(\text{saving coal via electrolysis}) = \frac{88.9}{\text{total heat input (HTGR)}} = \frac{88.9}{148.2} = 0.6 \qquad (7)$$

This is not a standard way of looking at thermal efficiency, but it is sensible in our case. The disadvantage of this comparison, as will be shown later, is that the comparison would change in favor of electrolysis if in the future a more efficient process for H_2 from coal would be developed.

Actually, eq 7 underestimates the amount of coal saved in electrolysis. Oxygen is generated together with the H_2 and if there is a synthetic fuel industry the O_2 could be utilized in other plants. If we give full credit to the O_2 we would save, based on present technology, an additional 9.7 kcal coal/g-mol of H_2 produced (see Figure 6), which changes the efficiency in eq 7 to

$$E(\text{saving coal}) = 98.6/148.2 = 66.5\% \qquad (8)$$

In section 3 we discussed a requirement that for the steam reforming route to be attractive it has to have a 30% advantage in the size of the nuclear reactor. Based on eq 8 this requires that its coal saving efficiency (E) should be better than 95% or 1.05 kcal nuclear heat/kcal of coal saved.

The stoichiometry of the nuclear steam reforming process is such that only 39.5 kcal of coal can be saved per g-mol of H_2 produced, which gives us immediately a bound on the total nuclear energy requirement that is permissible. We can now look at the thermodynamic and process constraint of nuclear steam reforming to see if such an expected efficiency can be reached under realistic design conditions. We can do this without any experimental data by just looking at the inherent constraints of the process.

5. Thermodynamic and Process Constraints of the Nuclear Reforming Route.

(a) Definition of Thermodynamic Constraints. When looking at the potential thermal efficiency of a new process it is always advisable to try to understand the nature of the constraints that limit and determine the thermal efficiency–cost tradeoffs of the new process vs. the old technology.

In Shinnar et al. (1982) we showed that there are two types of thermodynamic constraints: (1) hard thermodynamic constraints such as the decrease in free energy and (2) thermodynamic consequences of design decisions and available technology. As an example, in a steam power plant, the thermal efficiency is limited by the top temperature chosen due to water decomposition. The limitation due to the Carnot principle is here a result of our choice for the material of construction. Similarly, in a chemical plant the efficiency is limited by the heat of reaction of the process and the fact that we do not have efficient heat pumps to transfer energy from a low to a higher temperature.

We can therefore get a limiting efficiency from each process which is determined by such inherent constraints. This efficiency is the efficiency of an ideal cycle.

Such an ideal cycle, despite the fact that we run it without any driving forces at reversible conditions, has inherent losses compared to the Carnot cycle. Thus in a power plant transferring heat to a steam cycle at 700 °C introduces an inherent irreversible loss.

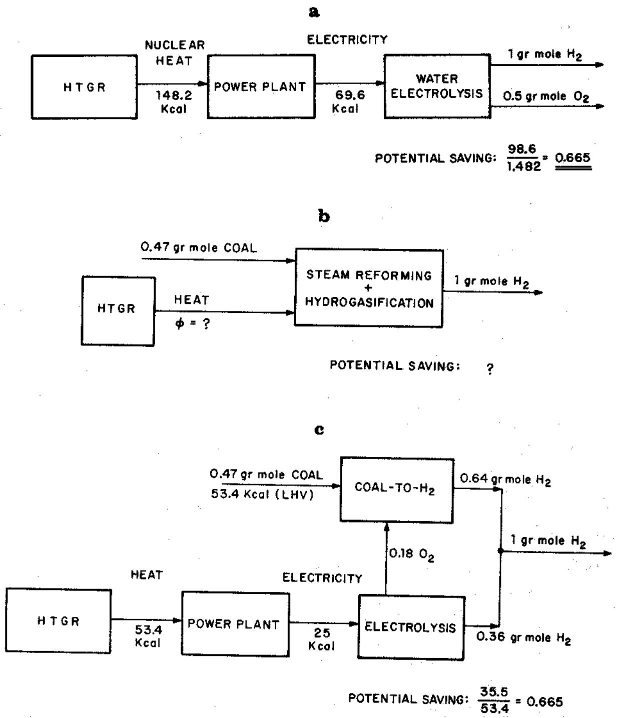

Figure 7. Potential coal saving for electrolysis, combined route, and nuclear steam reforming: (a) electrolytic hydrogen; (b) nuclear steam reforming; (c) hydrogen from a conventional coal plant integrated with a electrolysis plant to which the same amount of coal is introduced as in the nuclear steam reforming route.

In addition to these constraints, there are process constraints due to the need of finite driving forces which also lead to irreversibilities. Therefore, it is useful to distinguish between the two types of irreversibility. Let us now compare the constraints of the two routes (water electrolysis and nuclear steam reforming).

Both routes share the constraint of the Carnot law which here is a result of limiting the top temperature of the reactor to 1700 °F (see Shinnar et al., 1981). This is a thermodynamic consequence of a material constraint.

This is really the only inherent constraint the electrolysis process faces. In the electrolysis part there is no inherent constraint. All the losses are due to the need of finite driving forces to give reasonable investment cost. In the generation of electricity we have the further constraint that the power cycles are not Carnot cycles, but there is no need to further discuss this constraint. The overall efficiency of 47% is 62% of the Carnot efficiency. It can be increased but at considerable cost.

(b) Stoichiometric Limitations on the Amount of Coal Saved. What are the thermodynamic limitations of the nuclear steam reforming route? To answer this we look first at the amount of coal that can be saved.

Stoichiometrically, the minimum amount of carbon that is required is 47 kcal/g-mol of H_2 for carbon and 49.4 kcal (LHV)/g-mol of H_2 for coal (see Table I and Figure 4). As said before, our savings depend on the efficiency assumed for gasification of coal. We note that the potential for savings is less for the coal scheme (39.5 kcal/g-mol of H_2 if we use coal and 41.9 kcal/g-mol of H_2 for carbon feed).

However, there is also a process constraint that further limits the amount of coal that can be saved. Hydrogasification is a relatively slow reaction and its is hard to get complete conversion in a reasonably sized reactor. No commercial hydrogasifier exists. Until now most pilot plants operated with limited conversion using the unconverted char to manufacture the hydrogen. The best conversion achieved in the German pilot plant was 80%. A conversion of 95% is a reasonable assumption for the possible conversion. This further limits the amount of coal saved. We give a comparison of the coal inputs and potential savings in Figure 7 which updates the overall comparison of the three routes.

Table III. Individual Steps Reactions in the Nuclear Steam Reforming Process

A.1. $0.5CH_4 + 0.5H_2O(g) \rightarrow 0.5CO + 1.5H_2$ (1550 °F)
$\Delta H^\circ_{298} = 24.6$ kcal; $\Delta G^\circ_{298} = 17.0$ kcal
A.2. $0.5CO + 0.5H_2O(g) \rightarrow 0.5CO_2 + 0.5H_2$ (450 °F)
$\Delta H^\circ_{298} = -4.9$ kcal; $\Delta G^\circ_{298} = -3.4$ kcal
A.3. $H_2O(l) \rightarrow H_2O(g)$
$\Delta H^\circ_{298} = 10.52$ kcal; $\Delta G^\circ_{298} = 2.05$ kcal

A. $0.5CH_4 + H_2O(l) \rightarrow 0.5CH_2 + 2H_2$
$\Delta H^\circ_{298} = 30.23$ kcal; $\Delta G^\circ_{298} = 15.63$ kcal
B. $0.5C + H_2 \rightarrow 0.5CH_4$
$\Delta H^\circ_{298} = -8.84$ kcal; $\Delta G^\circ_{298} = -6.07$ kcal

overall:
$0.5C + H_2O \rightarrow 0.5CO_2 + H_2$
$\Delta H^\circ_{298} = 21.29$ kcal; $\Delta G^\circ_{298} = 9.56$ kcal

In the electrolysis route the thermal efficiency quoted included all energy needed to run the nuclear reactor complex. For the scheme in Figure 2 energy is needed to pump the helium through two heat exchanger circuits. This is discussed in detail by Shinnar et al. (1981). This energy strongly depends on the temperature of the heat required for the process, as the ΔT between the nuclear reactor and the final heat exchanger, delivering the heat to the process, determines the amount of helium that has to be pumped through the two loops. We will assume here, based on Shinnar et al. (1981), that the net heat transmitted to the process is 90% of the nuclear heat generated. Based on Figure 7, we can ask now how much nuclear heat can we afford. For coal at 95% conversion the maximum saved is 35.5 kcal. If we allow 1.05 kcal (nuclear heat)/kcal coal saved this gives 37.3 kcal for the nuclear heat and at 90% heat transfer efficiency this gives 33.6 kcal nuclear heat supplied to the nuclear steam reforming process.

We should also note that if the total net requirement of the process exceeds 53.4 kcal, the nuclear steam reforming process could replace coal less efficiently than electrolysis using electricity from an HTGR.

For carbon the permitted energy is larger as the stoichiometric coal requirements are larger depending on the quality of the coal. The maximum saving at 95% conversion is 39.4 kcal of carbon, which increases all the other numbers accordingly, and we could afford 37.3 kcal for the steam reforming process. However, our process requirements are increased by an almost identical factor. If we look at Figure 4 we note that the steam reformer for the coal case has a feed which is only 0.435 g-mol of $CH_{0.8}O_{0.1}$ instead of 0.5 g-mol of C, and the hydrogasifier is also smaller.

(c) Thermodynamic and Process Constraints of Steam Reforming of Methane. If we look at the energy requirement of the two sections in Figure 4 we note that steam reforming is highly endothermic while hydrogasification is exothermic. The question then arises how much of this exothermic heat can be used to meet the energy requirements of the steam reformer, such as steam generation. In practice a hydrogasifier is a net energy consumer as we will show later. Since the steam reformer is by far the biggest energy consumer of the total process, it makes sense to look at its constraints separately. We will start by breaking down (Table III) the steam reforming process into its individual stages in a more detailed way.

In discussing stoichiometric constraints on energy requirements, it is important to look at the individual steps.

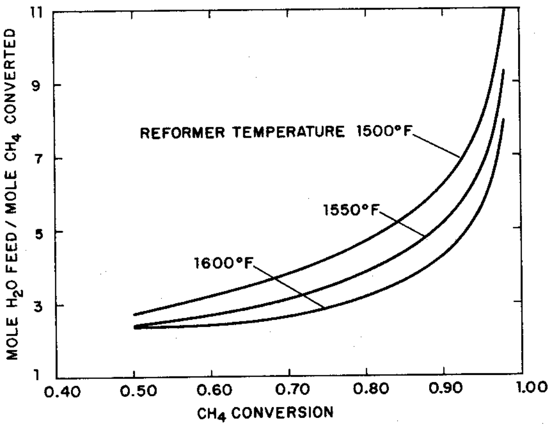

Figure 8. Minimum steam requirement in steam reforming of methane as a function of methane conversion and reformer temperature.

It is important to look how the different energy requirements of endothermic steps match with possible energy requirements of exothermic steps. This is not a hard thermodynamic constraint, as we could in theory use heat pumps. But it is a constraint in the context of an idealized flow sheet as discussed before.

The main energy requirements are in the steam reformer which is an identical process for the coal scheme and the carbon scheme. The size of the steam reformer for both cases is by coincidence proportional to the savings in coal. While in reality we would use coal, we will analyze the carbon case, which is simpler.

In Table III we have broken down the process into individual steps giving only the stoichiometric requirements to guarantee one g-mol of H_2. We also give the temperature of each step to see if heat can be transferred from one step to another. The minimum heat requirement is the heat of the overall reaction, which is 21.29 kcal. However, we have individual steps which require different temperatures to reach high conversion, and we have to match these steps. Stoichiometrically, the dominating step is the reaction

$$0.5CH_4 + 0.5H_2O_{(g)} \rightarrow 0.5CO + 1.5H_2$$

$$(\Delta H^\circ_{298} = 24.6 \text{ kcal; } 27 \text{ kcal at } 871\ ^\circ\text{C})$$

The reaction heat is required at high temperature and cannot be supplied by the exothermic reactions. Actually, we have to supply this heat at the temperature of the reaction (1600 °F (871 °C)) at which the heat of reaction is 27 kcal. The exothermic heat of the shift reaction could be applied to steam generation. We note that the stoichiometric constraint is severe. The heat requirement is very close to our goal of 37.3 kcal/g-mol of H_2.

Actually part of the shift reaction occurs in the steam reforming reactor, which reduces this limitation, and we therefore have to look at the equilibrium concentration of CO in the steam reformer which we will discuss later.

Steam reforming has one additional thermodynamic constraint. At the maximum temperature available due to initial limitations (1550 °F) conversion is incomplete and is a function of pressure and temperature. The standard pressure in steam reforming is generally 325 psia (22 atm). However, the process is limited not only by the maximum temperature of the reactor due to catalyst and material constraints, but also by the minimum temperature possible for the shift reaction. The latter is fixed by the kinetics of the available catalyst and is assumed here to be 450 °F.

Both limitations determine the maximum conversion of steam at equilibrium in each reaction and, therefore, the minimum excess steam required. Figure 8 shows the minimum total steam requirements as a function of methane conversion. The results are given for two typical methane conversions—89% and 65%. A conversion of 89% leads after CO_2 removal to a hydrogen purity of 97% in the final product gas, whereas conversion of 65% is equivalent to an 88% hydrogen purity. (The CO conversion is kept fixed at 100%). For completion, Figure 9 shows the steam requirements as a function of CH_4 conversion. Both figures are based on net hydrogen produced. It can be seen that if the methane conversion is lower, steam requirements decrease. However, the energy requirements of the hydrogasifier will increase since the CH_4 limits the conversion and increases the recycle.

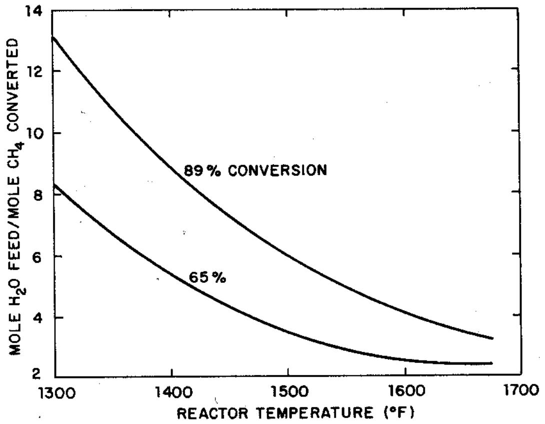

Figure 9. Minimum steam requirement in steam reforming of methane as a function of reformer temperature.

At 1550 °F with 89% methane conversion (97% hydrogen product purity), the steam requirements are 2.47 g-mol of steam per 0.5 g-mol of CH_4 converted, of which only 1./ mol is converted (see reaction A, Table III). Thus, 1.47 g-mol of steam has to be condensed below 450 °F (after shift) from a stream containing 50% inerts. Condensing steam from such a diluted stream below 450 °F is not only expensive but also leads to significant losses in thermal efficiency.

While part of this heat can still be used to compensate for practical efficiency losses, this does not change the fact that the minimum theoretical energy requirements of the process have to be increased by the heat of vaporization for the excess steam required. The minimum requirements for steam reforming are therefore at least 44.0 kcal. To this we would have to add the process losses due to finite driving forces. One important process loss for which thermodynamics provides very little guidance is the separation of CO_2 after the shift reactor. This process is also present in the manufacture of H_2 from coal. Any improvement would affect both processes. A reasonable estimate for this from current technology would be 4 kcal/g-mol of H_2. Our minimum estimate therefore approaches the limit of 53.4 kcal/g-mol of H_2 at which the thermal efficiency of both routes is the same.

Hydrogasification has no such theoretical limits. The temperature required for complete conversion is low but still high enough (1000 °F) to generate useful energy from the heat of reaction. In practice kinetic limitations require higher temperature (1700 °F) at which conversion is thermodynamically limited and the reaction therefore requires a high pressure. This leads to two losses: (a) The H_2 from steam reforming has to be compressed. (b) As conversion is incomplete, H_2 has either to be separated from the methane or passed through the steam reformer increasing the mass flow through the reformer and further increasing the excess steam required.

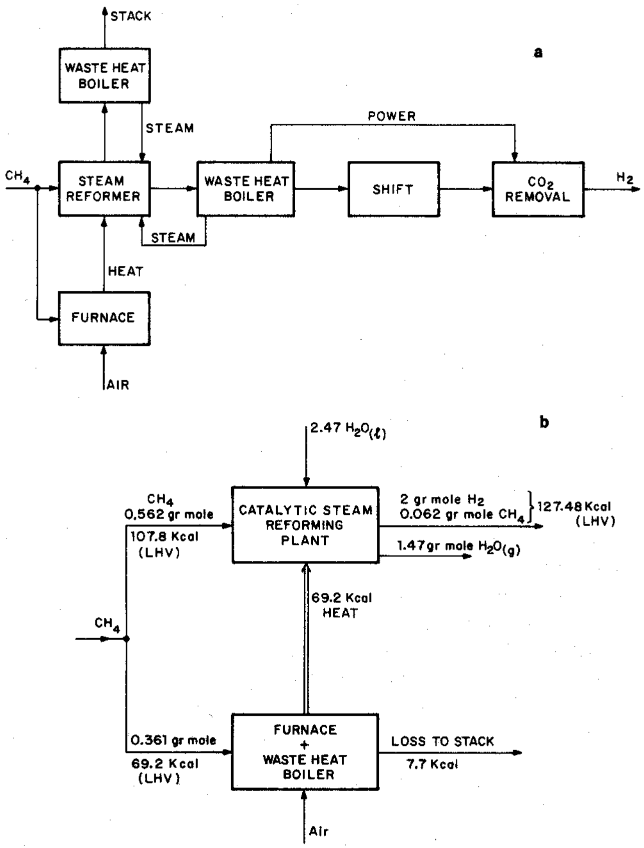

Figure 10. (a) Schematic flow sheet of steam reforming of methane to produce hydrogen. (b) Energy balance for conventional steam reforming plant of methane (basis 2 g-mol of H_2 produced).

Separation processes have a very low efficiency compared to thermodynamic requirements. As the thermodynamic constraints are very low, we will deal with hydrogasification in the context of practical energy requirements due to process constraints.

6. Process Constraints and Estimate of Thermal Efficiency for Steam Reforming of Methane.

In the previous section we devised thermodynamic constraints on steam reforming of methane using nuclear energy. As this limit was already high we could, in preliminary screening, stop at that place. But it is always good to get an estimate in different ways. Here, there is an easy way to estimate the energy requirement of the steam reforming part of the process. The steam reforming of methane to produce hydrogen is a well-developed industrial process, and since it is one of the steps in the overall process analyzed here, it can serve as a basis for comparison. The heat of reaction, as well as steam and all process energy requirements, is supplied by burning methane. A simplified flow sheet is given in Figure 10a. The methane is combusted in a furnace and part of the heat of combustion is supplied to the catalytic reformer. The hot gases are partially used to preheat the methane and the air, and partially to raise steam and to supply the energy requirement of the process by a waste heat boiler. In figure 10b we give an overall energy balance of the process based on carbon. To construct such a balance, it is sufficient if one knows the overall thermal efficiency of the process which is 72% (LHV) (Corneil, 1977).

$$[\text{LHV of product gas } (97\%\ H_2,\ 3\%\ CH_4)]/[\text{LHV of methane to reactor} + \text{LHV of methane to furnace}] = 72\%$$

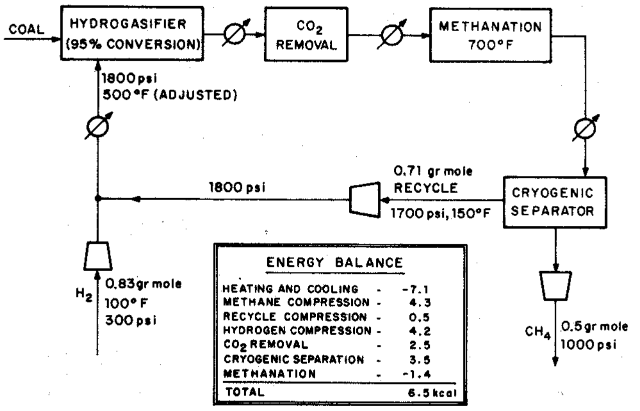

Figure 11. Flow sheet and energy balance for hydrogasification process.

In industrial hydrogen production methane conversion is only 89%. The same would apply to our process. In Figure 6 we used net flows of H_2 and neglected the recycle of methane. To be consistent we therefore give this unconverted methane as a separate feed and product of the plant. We note that the net heat supply of the process is 69.2 kcal/g-mol of H_2. This is reasonably consistent with our estimate of 48 kcal/g-mol of H_2 for the minimum energy consumption of an idealized flow sheet with no provision for driving forces.

Comparison with existing technology is a very important part of our method of economic analysis, both for cost and thermal efficiency. One should not accept such numbers blindly, as the design philosophy might here be different. Methane steam reforming was developed when methane was cheap and was not optimized. For minimum energy consumption, however, recent efforts to imporve it have led only to small improvements. The analysis of the previous section is helpful here as it clearly shows that the potential for improvement in thermal efficiency is limited. A 20% reduction in the energy cost would be a substantial gain for the process but would have no impact on our analysis as it would reduce the net energy input from 69.2 to 55.4 kcal/g-mol of H_2.

However, the 69.2 kcal (or the 55.4 kcal for the optimistic case) were based on net energy input to the process. We have to add to this the energy requirements of the two helium loops. At 90% efficiency 55.4 kcal requires a primary heat input from the nuclear reactor of 61.5 kcal or 1.56 kcal/kcal coal saved, which is by chance approximately the same as the heat requirements of the nuclear reactor to save 1 kcal coal in the electrolysis route.

Efficient process evaluation is an iterative process. If our results would have shown a strong advantage for the new route, we then would have to check it by a more detailed flow sheet. As the results are negative, such a detailed analysis is not required.

Let us now look at the practical efficiency we can hope for in a hydrogasifier. The minimum energy losses of a hydrogasifier are found by performing an energy balance around an optimistic adiabatic hydrogasifier, using the method of Shinnar and Kuo (1979). The simplified flow sheet is given in Figure 11. A fluidized bed hydrogasifier is fed with coal and operates at 1800 psi. Gas phase equilibrium is assumed at 1700 °F. The flow sheet in Figure 11 is based on coal instead of carbon as hydrogasification of coal has elements such as H_2S and CO_2 removal that are not present in carbon. A fluidized bed gasifier was chosen as it gives us higher thermal efficiency than a cocurrent gasifier.

The heat of the reactor is used to preheat the coal and the feed gas and energy is extracted by heat exchange from

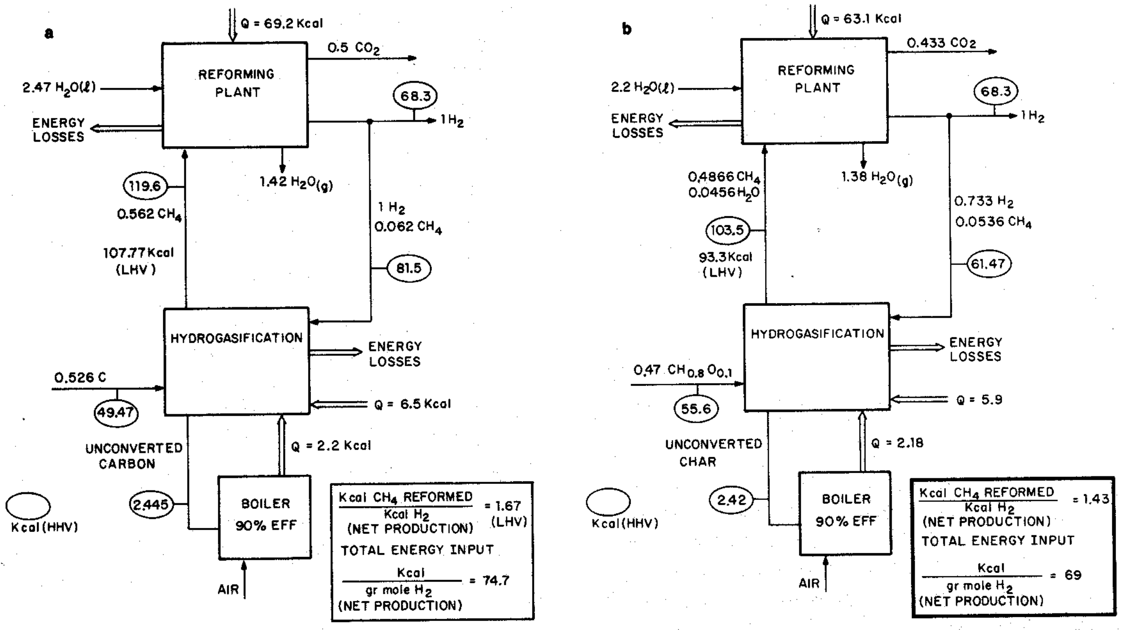

Figure 12. Revised flow sheet of the process in Figure 4: (a) carbon feed; (b) coal feed.

the product gas. The coal gas contains H_2S and some small amount of CO_2 which have to be removed. It also contains some CO which is converted to methane in a methanator. Conversion at 1700 °F is incomplete and the gas contains a large fraction of H_2 (60% in mole fraction). The H_2 has to be recycled, and in our flow sheet the recycle is separated from the methane by cryogenic separation. In this case the liquid methane is separated to provide the cooling for the cryogenic separator. The main energy consumption of the cryogenic separator is therefore recompression of the methane to the pressure of the methane steam reformer. A detailed energy balance is given in Figure 11. The conversion of the hydrogasifier was assumed to be 95%. While such chairs are conventionally discarded, we assume here that they are burned in a waste heat boiler at 90% efficiency. The system requires a net energy input of 6.5 kcal for generating the 0.5 g-mol of CH_4 which is the basis of our evaluation (1 g-mol net H_2). Real energy inputs would be higher as (1) real gasifiers do not achieve equilibrium, especially in slow reactions; at the high coal conversion rates assumed, one would expect the reaction to be quite slow; (2) the methane reformer does not achieve complete conversion and therefore CH_4 is recycled to the hydrogasifier which further reduces conversion and increases compression and separation needs.

No attempt was made to optimize the process, as the impact of such optimization on the total process would be small. As said before, the constraints are here due to the kinetics. At the temperature required for hydrogasification conversion is limited by thermodynamics. A high pressure (at least 1800 psi) is required to get reasonable conversion and reaction rates. As our steam reformer requires a lower pressure, this requires compression of the hydrogen.

While a real design would require such optimization, it is not needed here. For our purposes it is enough to realize that the hydrogasification section will need a small positive energy input despite its high exothermic heat of reaction.

For the carbon case we would therefore have to add at least another 6.5 kcal to the 69.2 kcal required in the steam reforming section. In Figure 12 we give now a corrected version of Figure 4 with real energy inputs according to our estimate. For the coal case the amount of methane to be reformed decreases from 0.5 g-mol/g-mol of H_2 to 0.435 or a reduction by 13%. The size of the hydrogasifier is also reduced by about 16% as we need less hydrogen to generate the methane. However, the coal saved decreases by 6% which makes the two cases practically equal. A revised version of Figure 4b is given in Figure 12b.

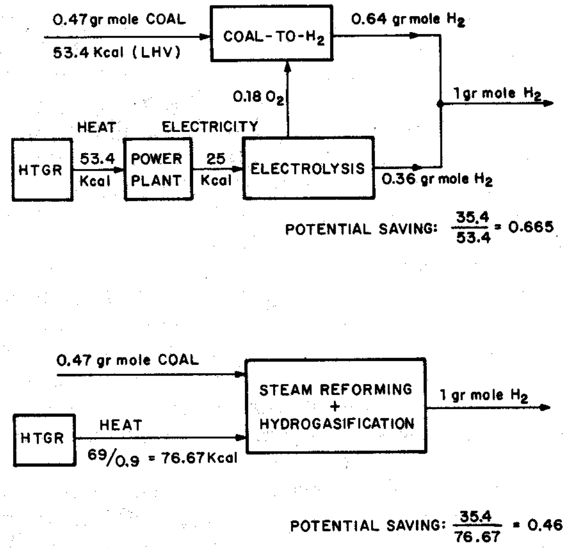

Figure 13. Energy flows for combined electrolysis and coal-to-hydrogen process, and steam reforming of methane.

We can now return to our comparison of Figure 7. In Figure 13 we give a revised energy balance for the two routes. In Figure 13 we have again included the energy required to transmit the heat from the HTGR through helium heat exchangers to the steam reforming process. We note that the electrolysis route has a potential advantage.

One reason for the disadvantage of the steam reforming route is based in the flow sheet itself; 1.7–2 mol of H_2 have to be generated for each net mole of H_2 produced, and then part of the free energy generated in the hydrogasifier is lost. It is this double work that makes reforming of methane unattractive in a coal-to-SNG or coal-to-H_2 plant, and reduces the thermal efficiency.

We can now look at the sensitivity of our results to our assumptions. For the steam reforming route our estimates are really optimistic lower bounds. For the comparison

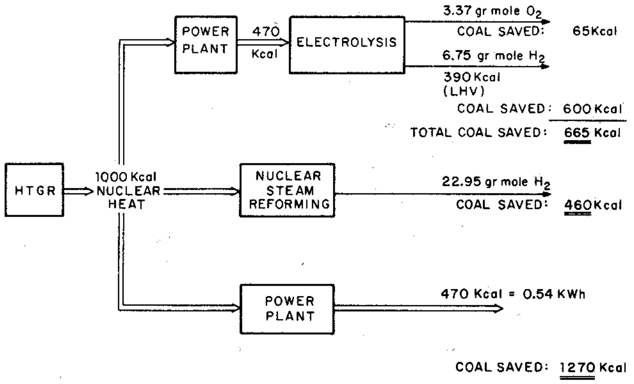

Figure 14. Saving coal by using nuclear heat in three different alternatives.

case we assumed an efficiency of 47% for the nuclear reactor and 85% for the electrolysis. Actually, for electrolysis an efficiency of 85% is feasible and has been achieved in the pilot plant. It is really a question of investment cost vs. operating cost. If we, however, reduce the efficiency of the HTGR to 45% and that of electrolysis to 70%, the requirements of the comparison case (electrolysis in combination with conventional coal-to-hydrogen) increases by 26% which would have no impact on our conclusion. Some might also quarrel with the fact that we gave full credit to the oxygen produced. If we assume that there will be a need at all for synthetic fuels from coal some credit is definitely justified. Even if we eliminate this credit, it will still not give the steam reforming route a sufficient advantage, as can be seen from Figure 13.

The most important assumption in our comparison is the choice of the base case. If we would compare the nuclear steam reforming route straightforward to electrolysis, then clearly nuclear steam reforming would have a better thermal efficiency, as can be seen from Figure 13. But it would also have a lower thermal efficiency than straightforward use of coal. Averaged efficiencies used for the joint use of coal and nuclear energy are meaningless unless one can show a synergism for the joint use as compared to separate uses.

In Figure 14 we show how much coal can be saved by the different alternatives, each receiving 1000 kcal nuclear heat. We also include here electricity generation from the HTGR. It is clear that electricity generation is more efficient in saving coal than either electrolysis or nuclear steam reforming.

We can now also go back and check in more detail our assumptions about relative costs. While the electrolysis route has a potential advantage in thermal efficiency, in the next section we will assume that both require the same nuclear reactor to save an equivalent amount of coal. As most engineers are familiar with cost data on the basis of investment per million Btu capacity per day we will, in the next section, use a basis of million Btu. The relative efficiency and heat requirements are obviously the same.

7. Investments Required

It is very difficult to obtain reliable costs for an HTGR, as one faces the tendency to underestimate costs in new developments. It is hard to imagine that it will lead to significant cost savings, compared to a standard nuclear reactors, though it might have other advantages such as safety. In a standard nuclear reactor the cost of the reactor itself is a small fraction of the total power station cost. Shielding and other expenses related to safety cost more than the nuclear reactor itself. Therefore, it will be assumed that the HTGR will be competitive with the conventional light water reactor for electricity generation. It is also assumed that the cost of kW(e) installed capacity is \$900 (1980) excluding interest during construction.

If electricity generation is eliminated, and the HTGR is used for heat only, a double helium loop has to be inserted (see Figure 1) to transfer the heat. The heat transfer surfaces will increase significantly since the temperature gradients are smaller, and the heat transfer coefficient for helium is much lower than for steam. Additional power is also needed to pump the gas through the heat exchangers. Most probably the coal conversion plant will be located at some distance from the reactor so it will have additional energy losses. Optimistically, it can be said that the heat transfer costs are equal, but the turbine for electricity generation is saved. That means that, at best, about \$125/kW(e) installed are saved, though the double helium loop case can, in practice, be more expensive. To simplify matters the \$125/kW(e) installed investment for the turbine generator is included in the investment of the electrolysis plant itself. The HTGR will then have the same cost based on primary heat delivered, or \$4,500 per MMBtu per day primary heat. (1 kW installed generates 24 kWh or 82000 Btu electricity per day which at 47% efficiency is equal to 0.175 MMBtu/day).

Table IV shows an estimate of the investments for the three processes. The investments numbers are in 1980 dollars and do not include contingency interest during construction or starting costs. The absolute numbers are not very reliable in terms of rapid inflation, but the comparative costs should be reasonably good. If the inherent problems of handling coal are disregarded (these problems are common to all synthetic fuel plants from coal and are included in the plant cost for coal), a large size coal-to-H_2 plant should cost about 2.0 to 2.5 times the cost of a plant for steam reforming of methane.

In present concepts of hydrogasification only 50–55% of the coal is gasified. The remaining char is used for hydrogen production. As 25% of the coal is devolatilized, the hydrogasifier actually gasifies only 25–30% of the carbon. At 95% coal conversion, the kinetics of the process require an increase in the gasifier size by a factor of 3. This penalty applies to the hydrogasifier in the SNG process (Figure 2), which gets the H_2 from the hydrogen process. If the H_2 is obtained from coal, the option of reducing the conversion and gasifying the unconverted char for H_2 is available. The coal-to-H_2 process in this evaluation was not credited with this advantagae, nor was it quantified since the results made this unnecessary.

In the absence of data, it is hard to estimate the cost of the hydrogasifier, but a minimum cost can be obtained. The minimum investment cost includes the whole hydrogasification complex, including Rectisdol, cryogenic separation, heat recovery, compression, etc. In an SNG process using a hydrogasifier, and conventional hydrogen from coal, that cost should be about 30–40% of the total investment cost. It is assumed that the whole plant for SNG will have approximately the same cost as an SNG plant from Western coal using a Lurgi type gasifier (\$6000 per MMBtu/day; see Table II). A lower bound for the cost of the hydrogasificiation complex will then be 0.3 × 1.43 × \$6000 = \$2600. The factor of 1.43 is used here since 1.43 MMBtu of methane have to be generated in the hydrogasifier for every MMBtu of H_2. As the hydrogasifier is required to be three times larger in size, compared to that in an SNG plant, the cost might increase to \$5000. It is noted from Table II that there is no chance that such a proposed hydrogen process will have a significantly cheaper investment cost compared to a coal-to-H_2 plant.

Table IV. Investment and Feed Requirements for the Processes (1980 \$/MMBtu H_2/Day)

H_2 from coal		H_2 from electrolysis using nuclear heat		H_2 from steam reforming of methane using nuclear heat		combined coal-to-H_2 and electrolysis plant	
section	investment \$	section	investment \$	section	investment \$	section	investment \$
coal handling; drying, grinding	600			coal handling; drying, grinding	400	coal handling; drying, grinding	400
offsites	200	offsites	200	offsites	200	offsites	200
gasifier	1200–1500	electrolysis plant	2500–4000	hydrogasifier (1.43 MMBtu CH_4/day)	2600–5000	gasifier	800–1000
shift	600–800	electricity generation (turbine generator only)	1800	methane reformer (1.73 MMBtu H_2/day)	3400	shift and acid gas removal	1000–1300
H_2 + CO_2 removal	1000–1200	nuclear reactor	11500	nuclear reactor	6000	steam and power	500–700
oxygen plant	1000–1200					electrolysis plant and electricity generation 0.36MMBtu H_2/day	1500–2100
steam + power	800–1000					nuclear reactor	4200
total	5400–6500		16000–17500		12600–15000		8600–9900
coal feed (MMBtu/day)	1.54		...		0.896		0.896
incremental investment (\$)			10600–11000		7200–8500		3200–3400
incremental investment/coal saved (\$/MMBtu/day)			6900–7200[a]		11200–13200		5000–5300

[a] No credit was taken here for the oxygen produced. This credit is taken in the combined plant (coal and electrolysis) in the last column of this table.

If, on the other hand, the total H_2 plant's cost is considered, the HTGR steam reforming route has an investment advantage over the electrolysis route. This is the same illusion as was referred to in the section on thermal efficiency. Less coal is saved and therefore it requires less nuclear energy. We give therefore in Table IV also the proper base case for comparison from Figures 6 and 12 that saves the same amount of coal. We assume here that the nuclear reactor required has the same size. The combined case has a synergistic savings. In investment we get credit for the oxygen plant and the steam process plant required to drive it. We note that this case has as very significant advantage over the steam reforming in the total investment required. The comparison in Table IV gives the steam reforming route an unjustified advantage as we assumed that the size of the nuclear reactor required to save a million Btu coal is exactly the same as in the combined route.

We can use Table IV to check an assumption made in the approximate analysis. There we came to the conclusion that in order for the nuclear steam reforming route to have a 20% cost advantage over electrolysis, it must have a 30% better lower nuclear energy requirement to save the same amount of coal. This was based on the assumption that the investment in the nonnuclear section is equal. A more detailed analysis shows that this was a too optimistic assumption, and a larger improvement would be required. Since the process evaluated does not achieve this advantage, there is no need to look at more precise cost analyses. However, if the new route would have been attractive, we would have had to go back and check the required investment and the potential thermal efficiency in more detail. We would also have had to give more thought to one important item neglected here, namely, the potential increase in cost due to the safety problems inherent in the direct use of nuclear heat in a coal plant (Kugeler, 1980).

8. Economics

It was shown before that all that can be achieved by a nuclear reactor is substitution of nuclear energy for coal. Direct use of nuclear heat increases the cost of the process itself. Electrolysis has the potential to achieve a lower investment cost compared to a coal-to-H_2 plant, but the savings are small compared to the cost of a nuclear reactor.

The question arises, is it attractive today to substitute nuclear heat or energy for coal in a hydrogen or synthetic fuel plant? It is not very attractive, especially if it is compared to the possibility of substituting nuclear energy for coal in electricity generation. One unit of heat from the HTGR replaces $1/1.5 = 0.66$ unit of coal in a coal-to-H_2 plant. Assuming the efficiency of generating electricity from coal in a power plant, with a scrubber, to be 37%, then the same 1 unit of heat from the HTGR, generating electricity with an efficiency of 47%, is able to replace $0.47/0.37 = 1.27$ units of coal, or twice the coal replaced by either electrolysis or by direct use of nuclear heat.

The minimum incremental investment for saving one MMBtu of coal per day is \$7000 (see Table IV), whereas the incremental investment for saving coal in electricity generation is negligible. (If interest during construction is neglected, the capital cost of a nuclear power plant and a coal combustion power plant are very close.) At standard utility accounting, \$7200 translates into capital and operating charges of $8.0 \times 10^{-4} \times \$7000 = \$5.6$ per MMBtu coal saved, to which the full cost of the nuclear fuel has to be added. If the nuclear fuel cost of \$1.5 (0.5/kWh) is added, it ends up with a cost of \$7.1 per MMBtu coal saved. While this might become attractive in the near future, it is still much less attractive than generation of electricity. The penalty of using nuclear energy for purposes other than generating electricity is typical of all such uses. At present, electricity is sold for the equivalent of \$12 per MMBtu electricity or \$6 per MMBtu of heat generated from an HTGR. If it is converted to H_2, the product sells at present at a much cheaper price per MMBtu than electricity. If that H_2 is used as fuel the price still drops, as the cost of high quality fuels is still only \$6–7 per MMBtu. Many energy sources which are attractive for electricity generation lose their attractiveness if the electricity is converted to a fuel or H_2.

Some may dispute here the cost of nuclear fuel as it does not include any costs related to the fuel cycle, such as waste disposal, etc. The real cost of nuclear fuel is not of interest in this analysis as it affects equally all nuclear applications.

One might also ask, how will this comparison be affected if one reduces the required rate of return on investment (see Naphthali and Shinnar, 1981)? Reducing the rate of return will reduce both the cost of hydrogen and the cost of electricity by the same ratio. Our general conclusion, therefore, is not affected.

9. Summary and Discussion

The results can be summarized as follows.

(1) Use of high temperature heat in production of H_2 from coal is less attractive than the use of the same heat to generate electricity and split water into H_2 and O_2. It is even under the most optimistic assumptions more expensive per unit of coal saved and has less potential for saving coal. It also suffers from inherent thermodynamic disadvantages.

(2) Neither hydrogen from electrolysis nor from direct use of nuclear heat is attractive in the near future, but it can become attractive as coal becomes expensive and scarce.

(3) If an HTGR will become attractive in cost, supplying nuclear heat, it will become more attractive as a source of electricity.

(4) Use of nuclear energy to replace coal by generating electricity is inherently more attractive than its use in generating hydrogen or synthetic fuels.

These conclusions are similar to those reached by Shinnar et al. (1981) for generation of H_2 by thermochemical or hybrid cycles, using high temperature heat from an HTGR.

From a policy point of view these conclusions have some interesting consequences. Development of the HTGR is justified only if it leads to either cheaper electricity or better and safer electricity generation. Conclusion 1 implies that if one wants to be prepared for the long-range future, where hydrogen from nonfossil sources becomes important for synthetic fuel production, one should concentrate on developing better plants for electrolysis of water. This can be done totally uncoupled from any development of nuclear reactors. If nuclear H_2 becomes attractive in the future, it will be easy to phase it into synthetic fuel production.

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