



Integrated Energy Systems for the 21st Century: Coal Gasification for Co-producing Hydrogen, Electricity and Liquid Fuels

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Interim Report

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**Integrated Energy Systems for the 21st Century: Coal
Gasification for Co-producing Hydrogen, Electricity and Liquid
Fuels**

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Abstract

This report illustrates the role that integrated energy systems, also known as “energyplexes”, could play in supplying energy demands in the long term. These systems could enable a flexible multi-fuel, multi-product strategy with both economic and environmental benefits. Their potential is highlighted here using the case of coal-fired, synthesis-gas-based gasification systems that allow co-producing hydrogen, electricity and liquid fuels and could be a key building block in a clean-coal technology strategy. Energyplexes could increase the adaptability and robustness of energy-services companies in the marketplace. On the one hand, they could provide them with flexibility in meeting demands in different market segments while achieving lower production costs. On the other hand, they could increase their robustness by reducing the risks of relying on a single feedstock. In addition, with the possibility of achieving high conversion efficiencies and low polluting emissions and facilitating carbon capture, they could deliver high-quality energy services in a cost-effective way while meeting stringent environmental requirements, in particular those that might arise in a world with constraints on greenhouse gases. Co-production, also known as poly-generation, strategies may contribute to improve the economics of the system and exploit potential synergies between the constituent processes.

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Integrated energy systems for the 21st century: Coal gasification for co-producing hydrogen, electricity and liquid fuels

Kei Yamashita and Leonardo Barreto

1. Introduction

One promising alternative to fulfill increasingly stringent criteria for providing energy services is the development and deployment of integrated energy conversion and end-use systems. The variety of such integrated systems is large and encompasses a number of options in the industry and energy sectors where processes are flexible, amenable to the inputs of different raw materials, and have the ability of cascading and recycling output products in order to minimize environmental impacts.

In the field of energy conversion, these integrated systems, also known as “energyplexes”, are highly efficient, incorporate advanced technologies that may have fuel flexibility (e.g., coal and biomass) and allow for product flexibility, e.g., various combinations of electricity, liquid fuels, hydrogen, chemicals and/or heat (DOE, 1999a; Williams *et al.*, 2000). Such systems could also allow for an efficient means of separating a number of pollutants and, when using carbon-rich feedstocks, for capturing carbon dioxide. These technologies can become a key option during the course of this century, since they are flexible and able to benefit from potential synergies to produce multiple energy carriers economically and cleanly.

Thanks to their product flexibility, the energyplexes would permit the application of poly-generation strategies. Poly-generation, or co-production, schemes have been highlighted in the literature as promising alternatives for the simultaneous production of electricity, hydrogen, synthetic liquid fuels, heat and/or chemicals (DOE, 1999a; Ni *et al.*, 2000; Williams *et al.*, 2000; Simbeck, 2001; NETL, 2001). Poly-generation schemes may contribute to improve the economic attractiveness of the different products and have the potential to reduce the costs of carbon capture and sequestration (Ni *et al.*, 2000; Simbeck, 2001). Some co-production schemes are already relatively well established. For instance, co-generation has become a highly efficient alternative for simultaneous production of electricity and heat. Others, however, are at a much earlier stage of development or being used only in very specific niche markets. It becomes important to understand the technologies that may enable poly-generation strategies to play a larger role in the global energy system in the long term, the potential benefits they may offer and the barriers their development and deployment could face.

In order to achieve these multiple purposes, a combination of technologies is required. Thus, “energyplexes” could incorporate hybrid systems that could take advantage of the characteristics of the individual components. The hybrid system could achieve higher conversion efficiencies and fulfill more purposes than the component technologies alone.

For instance, a hybrid system could combine a gas turbine with a high-temperature fuel cell for electricity generation (see e.g., NETL, 2000; Rao *et al.*, 2002).

Many different configurations of multi-fuel and/or multi-product energy systems are possible. Here, we examine one of them, namely that of an integrated energy system based on the production of synthesis gas (syngas) using a coal gasification process and capable of producing, or co-producing, hydrogen, electricity and liquid fuels.

The remainder of this report is organized as follows. Section 2 presents a general description of the “energyplexes” and their potential role in providing energy services in the long term and describes coal gasification technology under study here and reviews the potential for carbon capture in coal-based gasification systems. Section 3 presents our estimates for production costs of hydrogen using this technology and examines a potentially attractive poly-generation strategy, namely the co-production of hydrogen together with electricity. Section 4 examines two additional poly-generation schemes, involving the co-production of electricity together with clean liquid fuels. The first system co-produces electricity and so-called Fischer-Tropsch liquids, i.e., gasoline and diesel produced using the Fischer-Tropsch process, which is explained below. The second scheme illustrates the co-production of electricity and methanol. Finally, section 5 outlines some conclusions from this study.

2. Coal Gasification for Energyplexes

In this section we present general considerations about the “energyplexes” and highlight the potential of those systems based on the production of synthesis gas (syngas), a mixture of hydrogen and carbon oxides that could be produced from several feedstocks through different routes and converted into a number of chemicals and/or energy carriers. Next, we stress the importance of the development and deployment of clean-coal energy technologies as a transition strategy towards a more sustainable global energy system. Specifically, a cluster of clean-coal technologies could be instrumental in enabling those countries likely to rely on a coal-intensive development path in the medium term to achieve cleaner and more efficient energy systems. Furthermore, we focus on coal gasification as one of the promising technologies that could be strategic in accomplishing such a goal and describe its potential role in the production and co-production of hydrogen, electricity and clean liquid fuels. In addition, we highlight the fact that coal gasification could enable convenient ways for capturing carbon dioxide from coal-based energy systems, which appears to be an important pre-requisite for these systems to successfully diffuse in a world with increasing environmental constraints, in particular those related to climate change.

2.1. Energyplexes

The conception and development of multi-product and multi-fuel integrated energy systems has been motivated by increasing requirements for market flexibility, security of supply and environmental constraints and by the opportunities for synergies and complementarities between different technologies and energy carriers. Integrated systems capable of using several input feedstocks could be more robust, i.e., less reliant on a single primary-energy source and, consequently, less vulnerable to potential price volatility or resource scarcity. Also, having several products would allow these integrated systems to meet energy needs in different market segments, thus multiplying the possibilities for generating profits while achieving lower production costs. In addition, the integrated operation may facilitate the control of pollutants, which would be concentrated in a single facility. With these characteristics, the energyplexes could increase the capability of energy-services companies

to compete in traditional and innovative market segments, enhancing their flexibility to react to industry changes and economic uncertainty and helping them to manage risks associated with feedstock supply and market changes and cope with, among others, environmental and financial constraints.

In general, the “energyplexes” will rely on the integration of flexible subsystems, which could be combined according to specific needs and opportunities. Thus, efforts are necessary both on the development of the technologies that operate as building blocks and of techniques to ensure their compatibility and successful integrated operation. The latter refers, for instance, to approaches that allow adequately integrating modules for feedstock processing, power and synthetic-fuel production and emissions control, in order to realize the potential for improvements in efficiency, costs and environmental performance resulting from their combination.

The conception of “energyplexes” follows industrial-ecology principles, namely those that call for developing technologies and production schemes that increase the productivity of available natural resources and which, while being cost-effective, minimize waste by recycling and/or separating materials and substances that could produce undesired environmental effects (Lovins *et al.*, 1999; Thomas *et al.*, 2003).

This kind of technological system may bring a good degree of much-needed flexibility to the energy system. Flexibility here refers to “the ability to change and adapt easily to new conditions and circumstances” (Collins Cobuild Dictionary, 1996). In the energy sector, as in many other industries, flexibility is required at different levels due to a number of reasons.

At the company level, energy-services companies need to increase their capacity to respond to, among others, market changes and regulatory changes. This means both changes in the markets they supply (e.g., electricity, transportation fuels) and also in the markets where they buy the feedstocks (e.g., oil, coal and gas markets) to make their products. Changes may occur in the demand levels, the required quality of the products to be delivered, the prices and availability of the feedstocks, the relative attractiveness of a given market segment, etc. In addition, changes may occur in the environmental legislation or the competition rules. These changes may bring about increases in production costs, different technology requirements and difficult-to-manage industry-wide reconfigurations. However, they could also provide new business opportunities.

Flexibility is also required at the energy-systems level. Here, we refer to it mainly as the ability of the system to effect a transition towards a different path, specifically to evolve towards a sustainable form in the long term, in view of huge technological, social and economic uncertainties. With long-lived infrastructures and technological regimes, the energy system exhibits a large inertia. Nonetheless, in the long term, substantial changes in the energy systems could occur.

It is necessary to “bridge” these two aspects. Technology choices that, on the one hand, enable companies to keep or increase their ability to adapt in view of the changes in the marketplace and can be compatible with current structures and markets and, on the other hand, contribute in preparing the system for a long-term transition towards sustainability are required. That is, technologies are necessary that help in “keeping the options open” both at the company and system levels. Here is where “energyplexes” may have a crucial role.

Among others, one attractive possibility is that of “energyplexes” based on the production of synthesis gas (hereon referred to as syngas), a mixture of hydrogen and carbon oxides that can be generated by a variety of processes and feedstocks and can be transformed into a number of chemicals and/or energy carriers. In such systems, syngas operates as the key enabling energy carrier for the multi-fuel and multi-product strategy (see Figure 1). On the one hand, syngas can be obtained from different feedstocks, not only natural gas but also solid feedstocks like coal and biomass, allowing their conversion into higher quality, cleaner and more flexible energy carriers. Moreover, several of these syngas production systems are very similar or at least compatible to some extent. These two conditions facilitate the introduction of multi-fuel systems. On the other hand, syngas allows obtaining a flexible mix of products, electricity, hydrogen, Di-methyl-ether, chemicals, heat, and CO₂, facilitating an adaptable multi-product strategy.

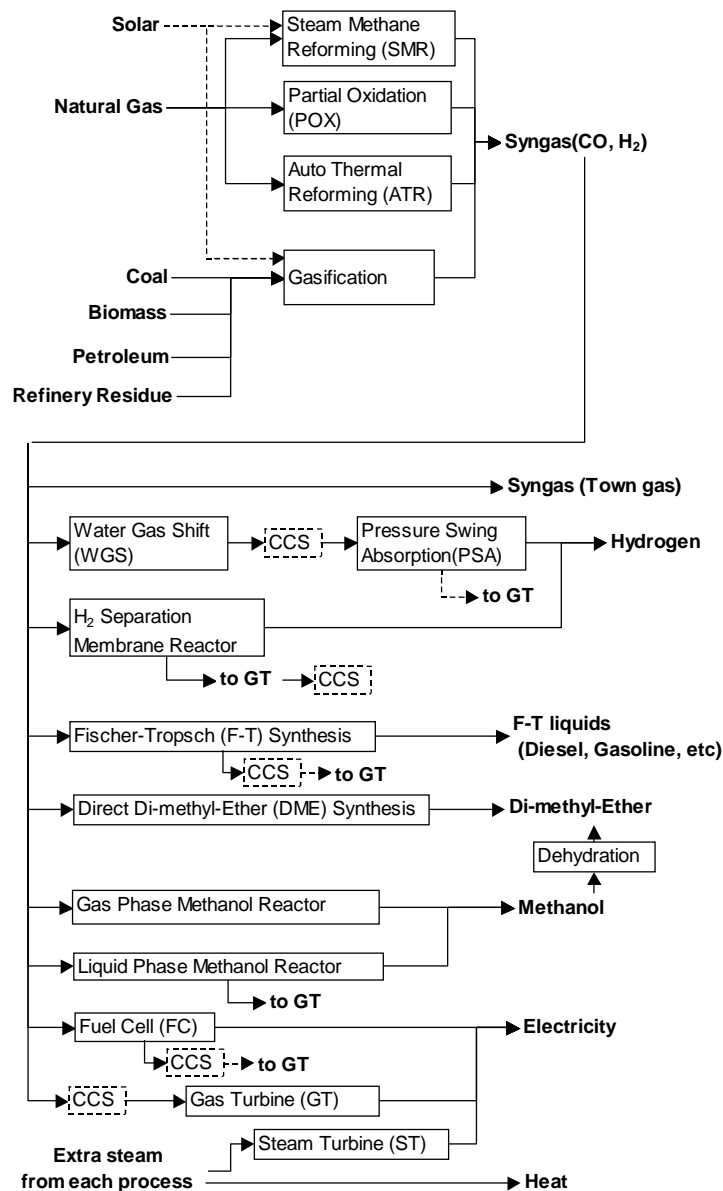


Figure 1: Alternative syngas related energy conversion technologies and pathways. The figure illustrates the flexibility of syngas-based systems. Syngas can be obtained from a variety of feedstocks and used to produce a wide range of products. The abbreviation CC stands for combined-cycle gas turbine. GT stands for single-cycle gas turbine. Some possibilities for carbon capture and storage (denoted as CCS) are also shown.

As illustrated by Figure 1, many alternative pathways for integrated energy systems based on syngas are possible. Here, we concentrate on the examination of systems using coal gasification for the production of hydrogen, electricity and clean liquid fuels. Still, the variety of configurations based on coal gasification is large and we only analyze some illustrative systems in this study.

Gasification could be one of the key technologies of coal and/or biomass-based “energyplexes”. It allows converting them into higher-quality, cleaner and more flexible energy carriers, avoiding the disadvantages of their direct use. In addition, with this technology, very low levels of air pollutants and manageable levels of solid and liquid waste can be obtained (Williams, 2001). Also, the technology benefits from advances in combined-cycle turbines, which is something conventional coal and biomass technologies do not permit.

Moreover, if the development of natural gas production, transportation and conversion infrastructures and technologies would bring the global energy system into an “energy gases era” (Nakićenović *et al.*, 2000), syngas could be a part of it together with natural gas and hydrogen. This could enable coal to become compatible with a gases-dominated energy system and would open the possibility for different production systems to share common transport and delivery infrastructures.

2.2. Clean-coal technologies

Coal continues to be a strategic indigenous primary-energy source in a number of countries and its global reserves and resources are abundant and more evenly distributed than oil or natural gas (see e.g., Rogner, 1997, 2000; BP, 2002). As such, coal could play an important role in the future global energy system, in particular if security-of-supply considerations become more pressing. Therefore, it becomes necessary to develop and deploy clean-coal technologies such that the mining, transport, preparation and conversion of coal into higher quality and more convenient energy carriers could be achieved in an efficient and clean manner with minimal environmental impacts.

Clean-coal technology strategies are being pursued, both at the international level (IEA/CERT, 2002; IEA/CIAB, 2002) and the national level, in a number of countries (see e.g., DOE, 1999b; UKDTI, 2001; NRCan, 2003). They involve a number of actions to control pollutants from today’s coal-based energy technologies and the development of advanced coal-based systems able to overcome some of their major shortcomings. While the former are necessary to reduce the significant environmental impacts of today’s coal use, in particular in the electricity sector, only the latter could allow coal to play a meaningful role in a transition towards a more sustainable global energy system.

Clearly, clean-coal technologies would be but only one component of a comprehensive technology strategy towards sustainable energy systems. Moreover, in the very long term, coal could be replaced by other, cleaner, less carbon-intensive primary sources. However, since energy infrastructures and supply technologies are long-lived, the transition would span through at least several decades. In the meantime, it is important to ensure that “bridging” technologies are deployed, which minimize the negative effects during the transition. In doing so, a cluster of advanced, highly efficient, coal-based technologies can play a significant role.

In addition, for many developing countries the challenge of achieving low-emission energy systems in the long-term would, among other actions, entail the ability to avoid installing

the fossil-based energy technologies to which they have access today and moving directly to cleaner and more efficient systems. Since several of those countries (e.g., China, India) are likely to base the development of their energy systems, at least in the short and medium term, on indigenous coal resources, the deployment of clean-coal technologies could be instrumental in achieving such a goal.

This technology cluster could prevent that more polluting, less efficient coal-based conversion technologies are installed and enhance the possibilities for transforming coal into more convenient final-energy carriers, thus contributing to phase out its direct uses. Specifically, syngas coal-fired “energyplexes” could play a strategic role in accomplishing such a goal (Williams, 2001). The successful deployment of such clean-coal technology cluster at a large scale of course would be, among other factors, linked to overcoming the obstacles for establishing sound business partnerships and co-operation mechanisms to transfer clean-coal technologies to these countries (IEA/CIAB, 2002).

2.3. Coal gasification

Coal gasification appears as a technology that could be instrumental in achieving the above-mentioned goals for clean-coal technologies (Williams, 2001). The gasification process is a well-established technology that converts a solid feedstock (e.g., coal, biomass) to a synthetic gas (syngas) using steam and an oxidant (Basye and Swaminathan, 1997). In this process, coal is first ground to a fine powder and then mixed with water to create a solid-content suspension suitable as input to a gasifier, where it is partially oxidized by pure oxygen or air. Using pure oxygen (i.e., the so-called O₂-blown gasifier) instead of air is more advantageous because it is difficult to separate hydrogen from nitrogen if air is used. From this reaction, a syngas consisting mainly of hydrogen and carbon monoxide is obtained. The syngas is cleaned to remove sulfur and coal ashes.

The clean syngas can be used directly as town gas or as input for the production of electricity and/or fuels, e.g., synthetic, hydrogen, methanol, Fischer-Tropsch (F-T) liquid fuels, among others. Hydrogen can be separated through a gas-shifting process that removes carbon dioxide from the syngas. A highly concentrated stream of CO₂ can be separated, thus facilitating its capture and storage in case it is needed. In a conventional system, the resulting hydrogen-rich syngas is purified in a pressure swing adsorption (PSA) unit and high-quality hydrogen is obtained (Williams, 2001).

As for electricity, it can be produced using the clean syngas directly as input to a combustion process such as a combined-cycle turbine, feeding it to a high-temperature fuel cell (e.g., SOFC) or using both technologies in a turbine/fuel cell hybrid system, which could achieve higher conversion efficiencies than the turbine or the fuel cell in a stand-alone mode. Alternatively, hydrogen could be produced first and then used as input to a fuel cell or to a hydrogen-fired turbine. The first alternative is the approach followed by Integrated Gasification Combined Cycle (IGCC) power plants, from which the coal gasification process is a key component.

The coal gasification technology is well suited for the co-production of hydrogen and electricity. Several alternatives are possible, involving different combinations of technologies for hydrogen production, electricity generation and CO₂ capture (see e.g., Gray and Tomlinson, 2002; Kreutz *et al.*, 2002; Parsons Group, 2002). Co-production could increase the overall efficiency of the process and provide some economic benefits. In general, the mix of both products in such a scheme would depend on their relative prices.

Liquid fuels can be produced by passing the clean syngas through a synthesis process. Different alternatives for production of, among others, methanol, Di-methyl-ether (DME) and Fischer-Tropsch (F-T) liquids (diesel, gasoline) are available (see e.g., Gray and Tomlinson, 2001; NETL, 2001). Syngas-based systems allow for producing liquid fuels with a low content of a number of pollutants. In several system configurations, electricity can be generated as a co-product. Having such a co-production scheme may offer several advantages such as reducing the production costs of the liquid products and facilitating carbon capture (e.g., in the case of F-T liquids), among others.

The coal gasification technology is at an early commercialization stage in the energy sector, mainly as part of IGCC power plants. Likely, IGCC plants will be introduced first for power generation applications only. However, these facilities could shift towards a co-production mode later on. Initially, syngas-based poly-generation strategies could include electricity, heat and/or chemicals. However, alternative poly-generation strategies could also prove attractive and be feasible early on. Specifically, as environmental requirements for transportation fuels become more stringent, co-production of electricity and clean synthetic liquid fuels could offer interesting opportunities for companies to meet energy needs in the electricity and transportation sectors simultaneously, while reducing negative environmental effects.

In the long run, as hydrogen makes some inroads as a final-energy carrier, the co-production facilities could be adapted to include it as an additional product or concentrate on the production of hydrogen together with electricity. Even more, if carbon capture in power plants becomes necessary, IGCC plants could be easily adapted to incorporate it (IEA/CERT, 2002). Introducing carbon capture could pave the way for co-production of hydrogen and electricity, because the pre-combustion capture approach that would be applied to IGCC power plants is essentially the same process for hydrogen production.

Thus, these technologies may provide energy-services companies with new business opportunities. These companies could meet different market segments, thus diversifying their sources of profit, at lower costs. In the short term, revenues could, for instance, come from the co-production of electricity and liquid synthetic fuels. In the long term, the sources of profit could be the sales of hydrogen and electricity and potential credits for carbon capture and storage (Lovins and Williams, 1999).

Today, in some countries (e.g., China), the gasification technology is more extensively applied in the chemical and oil industries, e.g., for the production of chemicals or hydrogen as a chemical feedstock. There, another strategy could be followed (Ni *et al.*, 2000; Larson, 2002). Initially, gasification technologies based on oil residues or coal would mainly provide chemicals and/or heat. Later on, while still operating mainly as part of chemical facilities or refineries, gasification-based plants could start selling excess power to the network. The success of this strategy would depend on the price at which electricity can be sold to the network and on the degree of success that market reforms in the electricity sector may have in these countries. In the long term, these facilities could also sell hydrogen if a market for it as an energy carrier develops and implement the capture and storage of carbon dioxide if necessary (Larson, 2002). Eventually, integrated companies could emerge that supply a wide range of products both in the chemical and energy sectors. In this way, current expertise on these technologies in the chemical industry could be gradually transferred to energy-services companies.

2.4. Capturing CO₂ from coal-based gasification systems

The increasing evidence of anthropogenic interference with the earth's climate system and mounting concerns about possible serious adverse impacts of future global climate change (IPCC, 2001) call for a transition towards a global energy system with a low release of greenhouse gases to the atmosphere in the long term. Carbon capture and storage (CCS) could permit the use of carbon-rich primary energy sources while reducing their net carbon emissions to the atmosphere (Socolow, 1997; DOE, 1999c). Hydrogen production from fossil fuels or biomass offers interesting possibilities for carbon capture. Specifically, gasification systems would be well suited since, as mentioned above, a highly concentrated CO₂ stream can be obtained during the process.

In light of the fact that coal is the most carbon-intensive fossil fuel, conceiving technology solutions to deal with the associated carbon dioxide emissions appears as a sound step in the direction of facilitating the emergence of a cluster of advanced coal-based technologies that could meet increasing energy needs while complying with strict environmental standards. In this regard, CCS systems would be a key component of a clean-coal technology strategy.

However, a number of technical, economical, environmental and public-acceptance issues regarding CCS systems are still to be resolved. Carbon capture technologies are currently under development and face a number of challenges. Among others, they must become less energy-intensive and more cost-effective, as well as increase the CO₂ capture efficiency and be better integrated into the energy conversion plants. Additionally, not less challenging, efforts are required on the long-term storage systems. A better assessment of the storage potential of different reservoirs, their leakage characteristics and associated risks and costs is required. Furthermore, the environmental impacts of both carbon storage and leakage must be quantified and the overall effectiveness of the storage schemes need to be evaluated and monitored (see e.g., NCCTI, 2002).

Moreover, the CCS option should be seen as part of a more comprehensive greenhouse gases management strategy, playing a complementary role to the decarbonization of the energy supply mix and efficiency improvements in both the supply and demand sides. Eventually, as the latter progresses, energy systems could move away from fossil resources. But, given its significant inertia, transforming the global energy system takes a very long time. Thus, it appears to be worthwhile to ensure that the environmental effects of the fossil-based systems that would bridge this transition are minimized. In doing so, carbon capture and storage could have a major contribution.

Given the reduced number of actors, large facilities and a relatively wide range of technological options, the electricity sector represents a primary target for carbon emission reductions. Thus, CCS is likely to be introduced first in fossil-fired power plants, provided it becomes a competitive carbon mitigation option and barriers are overcome. Although several possibilities for carbon capture in power plants are available (David and Herzog, 2000; Simbeck, 2001; IEA/CERT, 2002), some analyses (see e.g. Riahi *et al.*, 2003) have suggested that in the long term coal-fired IGCC power plants equipped with pre-combustion capture could have an important role in a carbon-constrained fossil electricity system.

Since, as mentioned above, the same process is used for hydrogen production from coal, the application of pre-combustion carbon capture approaches for IGCC power plants could make the co-production of hydrogen and electricity an attractive approach. This could pave the way for the introduction of hydrogen as an energy carrier in the long run as a suitable

complement to electricity, and for the development and deployment of integrated multi-product energy systems.

3. Co-production of Hydrogen and Electricity from Coal with CO₂ Capture

Hydrogen is a very promising energy carrier for the long term. It can meet a wide range of energy needs in different end-use sectors efficiently and with little or no pollution at the point of use. Hydrogen can be made from a broad portfolio of primary resources, coal among others, having the potential to diversify the energy supply system. Hydrogen production systems can be developed according to the feedstocks available in different regions. This may bring security-of-supply benefits and makes it attractive for facilitating the transition to a sustainable energy system in the long term (Marchetti, 1973; Ogden, 1999; Barreto *et al.*, 2003).

In the distant future, hydrogen could become an important energy commodity at the global level. Initially, hydrogen could be produced from the current competitive fossil fuels. At a later stage, as the market develops, the production system could evolve towards renewable resources. Although natural-gas-based hydrogen is the most competitive option today, coal-based hydrogen could be an interesting possibility for those world regions where natural gas is not available or expensive. In addition, new technology innovations could render coal-based hydrogen more competitive.

Electricity, on the other hand, has become a vital energy carrier in today's world and its importance will certainly increase substantially in the future. The electricity generation, transmission and distribution systems, as well as the institutions and markets associated with them, are evolving and significant structural changes in the global electricity mix and corresponding business models could be expected in the long run. Even so, fossil power plants are bound to continue playing a significant role in meeting the growing world electricity consumption well into the future, and coal-fired technologies could provide an important share of this fossil-based electricity.

This makes necessary the development and deployment of cleaner coal-based electricity generation technologies. A number of stringent environmental requirements are already imposed on the fossil-fired power plants going on-line today. In the long term, one important not-yet-addressed aspect concerns their carbon emissions. In this respect, gasification technologies may offer an attractive option, which at the same time could contribute in paving the way for the introduction of hydrogen in the long term.

In this section, we present our estimation of hydrogen production costs from coal gasification for two specific system configurations and additional calculations illustrating a potentially attractive poly-generation strategy, namely the co-production of hydrogen together with electricity.

3.1. Hydrogen production from coal with CO₂ capture

Here, as an illustration, we estimate costs of hydrogen produced by coal gasification for two alternative systems. The first system is a conventional coal gasification process using a Pressure Swing-Adsorption (PSA) unit for hydrogen separation. The second system uses a membrane-based system for the same purpose. For the first (conventional) system, we consider two cases with and without carbon capture. For the second system, the membrane-

based configuration, only the case with CO₂ capture is considered. For comparison, the costs of hydrogen production from steam reforming of natural gas using a PSA unit for hydrogen separation (with and without carbon capture) are also presented.

3.1.1. Technical description

3.1.1.1. Hydrogen production from coal using a PSA unit (conventional system)

The conventional system for hydrogen production from coal is shown in Figure 2. This system uses a PSA unit for hydrogen separation. The high-pressure syngas produced in the gasifier is cooled and cleaned of particles. Steam is injected into the gas stream, and the CO in the syngas is shifted to hydrogen and CO₂ in the shift converter utilizing sulfur-tolerant shift catalysts. The gas can be cleaned of sulfur in a single-stage physical absorption unit called Selexol. For the CO₂ removal case, the Selexol unit consists of two absorbers: the first absorbs H₂S from the cooled syngas¹, providing a desulfurized syngas, and the second absorbs CO₂ from the desulfurized syngas. Pure hydrogen is separated in a PSA unit, and the remaining gas stream from the PSA, which is called the purge gas, is fired in a heat recovery steam generator (HRSG). Steam produced from the HRSG, and the hot gas cooling, is used to produce power for in-plant use and the balance for sale.

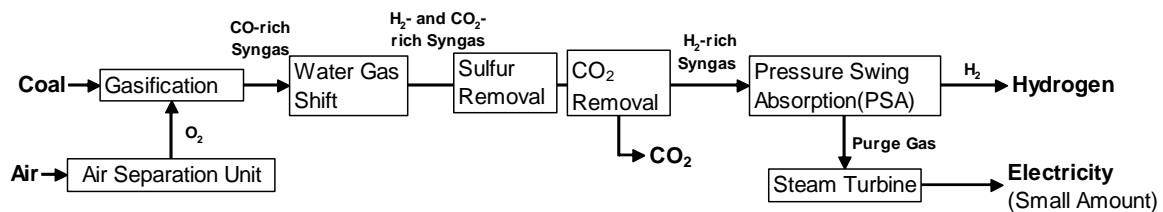


Figure 2: Block flow diagram of a conventional system for hydrogen production from coal using a Pressure Swing Adsorption (PSA) unit with CO₂ capture. For the case without CO₂ capture case, the block of CO₂ removal is to be omitted.

3.1.1.2. Hydrogen production from coal using a membrane reactor

An interesting alternative is the use of membrane reactors for hydrogen and CO₂ separation (see e.g. Williams, 1999; Shah and Drnevlch, 2000). Different types of membrane reactors are being tested, ceramic (inorganic) among others. Membrane technologies are at an early R&D stage. Their introduction as a viable alternative will depend very much on the advances made in materials and on the development of the separation technologies. In particular, it has to be ensured, among others, that the membrane systems are able to operate adequately under the difficult conditions (high temperatures and pressures and harsh chemical environments) associated with coal gasification processes and that they can be adequately integrated with other components of the plants. Also, costs of membrane reactors and their future development are much more uncertain than those of other components. Nevertheless, using membrane reactors could allow for the production of hydrogen at the

¹ Elementary sulfur can be recovered from H₂S and commercially sold in sulfur markets for, among others, production of fertilizers. However, if sulfur were to be generated in high enough quantities, sulfur markets could saturate. In such case, it would have to be disposed of as solid waste (Williams, 2001).

required purity from syngas without a water-gas shift converter or hydrogen purification system.

A block flow diagram of the plant is shown in Figure 3. Key process components are an O₂-blown gasifier, a hydrogen separation membrane reactor (HSMR), and an O₂-fired combustor followed by a turbine expander.

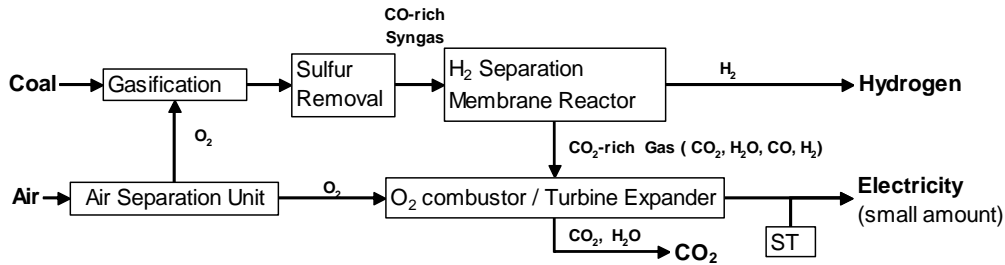


Figure 3: Block flow diagram of a membrane-based system for hydrogen production from coal with CO₂ capture. A hydrogen separation membrane reactor (HSMR) could function both as a syngas shifting reactor and a hydrogen separation unit, which might bring cost reduction and efficiency improvement for hydrogen production.

The hot raw gas produced in the gasifier is cleaned of sulfur and particulates. The gas enters the HSMR to be shifted and hydrogen is extracted. The hydrogen produced from the HSMR is over 99.5% pure. It is processed through a heat recovery steam generator and is compressed for pipeline transportation.

The CO₂-rich gas leaving the HSMR contains about 5% of the fuel value of the inlet syngas stream. This gas goes to the gas turbine combustor with which oxygen is injected to convert CO and hydrogen to CO₂ and H₂O, respectively. The hot gas is expanded through a turbine expander to produce electric power. The gas is cooled in a heat recovery steam generator, and the steam produced is combined with other steam produced from cooling the hydrogen to be used for process applications and power generation. The CO₂ stream containing H₂O is cooled and dried to obtain a pure CO₂ for sequestration.

3.1.1.3. Hydrogen production from natural gas (reference system)

Steam reforming of hydrocarbons continues to be the most efficient, economical, and widely used process for production of hydrogen. The gas-fired steam methane reforming system used for comparison in this study is shown in Figure 4.

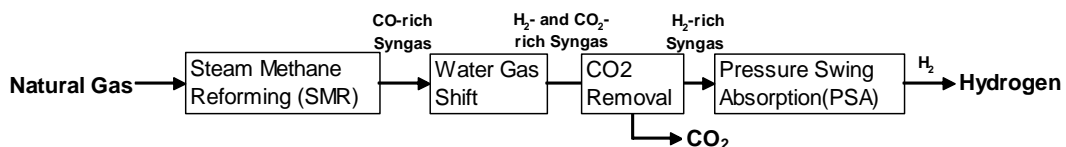


Figure 4: Block flow diagram of hydrogen production from natural gas with CO₂ capture (Reference System). For the case without CO₂ capture, the block of CO₂ removal is to be omitted.

The natural gas is mixed with process steam to be converted to carbon oxide and hydrogen in a reformer. After the reformer, the processed gas is passed through a heat recovery step and is fed into a water gas shift reactor to produce additional hydrogen. The exit gas is predominantly hydrogen and CO₂ with some residual CO and methane.

For the CO₂ capture case, CO₂ is removed by chemical absorption with a highly selective amine and is later stripped off by hot steam. Treated gas from the amine unit is fed directly into the PSA unit where hydrogen is purified.

3.1.2. Estimation of hydrogen production costs

Here we present the estimated hydrogen production costs of the hydrogen production technologies described above. Our calculation is based on system characteristics derived from several literature sources (see data in Appendix 1 and Appendix 2 for details) under a common set of assumptions, thus obtaining mean values and ranges for the production costs. Table 1 summarizes the performance, investment costs and operation and maintenance (O&M) costs of the hydrogen production technologies analyzed in this report². Costs are given in US dollars for the year 2000. Figure 5 presents the investment costs of these technologies as a function of hydrogen production capacities.

Table 1: Summary of the performance, investments costs and O&M costs of the hydrogen production technologies from several literature sources. This table also contains our estimation of hydrogen production costs.

Technology name	Hydrogen capacity ^a	Feedstock ratio ^b	Electricity output ratio ^c	CO ₂ capture efficiency	Investment cost	O&M cost	Estimated hydrogen production cost
	Million Nm ³ -H ₂ /day	GJ/GJ-H ₂	GJ _e /GJ-H ₂	%	US\$/Nm ³ H ₂ /day	US\$/ year - Nm ³ H ₂ /day	US\$/GJ-H ₂
Natural gas SMR + PSA without CO ₂ capture (NG PSA)	2.8 – 23.9	1.23 – 1.35	(0.018) – (0.010)	0	34 – 50	1.0 – 2.9	5.8 – 6.4
Natural gas SMR + PSA with CO ₂ capture (NG PSA w/CO ₂)	4.2 – 23.9	1.24 – 1.26	(0.040) – (0.070)	70	39 – 54	2.1 – 3.1	6.6 – 7.5
Coal Gasification + PSA without CO ₂ capture (Coal PSA)	3.2 – 6.9	1.54 – 1.69	0.037 – 0.081	0	101 – 112	3.6 – 6.6	6.6 – 7.5
Coal Gasification + PSA with CO ₂ capture (Coal PSA w/CO ₂)	3.4 – 9.0	1.29 – 1.86	(0.176) – 0.054	87 – 92	108 – 133	3.7 – 8.0	7.6 – 11.0
Coal Gasification + HSMR with CO ₂ capture (Coal Mem w/CO ₂)	3.5 – 6.8	1.26 – 1.58	(0.029) – 0.044	94 – 100	99 – 127	3.1 – 5.6	7.1 – 8.4

^a This is the capacity range of hydrogen plants whose cost data are available in this report.

^b The feedstock ratio is defined as: [the energy content [the energy content (HHV basis) of feedstock input to the process]/[(HHV basis) of product (hydrogen)]

^c The electricity output ratio is defined as: [the net electricity output]/[the energy content (HHV basis) of product (hydrogen)]. Negative figures, which are indicated by (), mean that external input of electricity is needed.

² Unless specified otherwise, all monetary values are expressed in constant 2000 US dollars and all energy values are based on higher heat value (HHV) in this report.

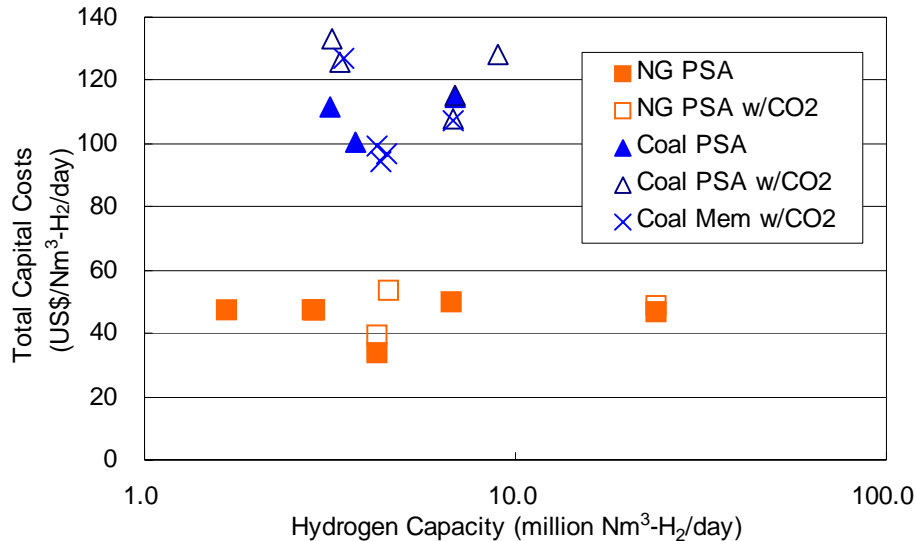


Figure 5: Investment costs per daily production capacity of hydrogen as a function of hydrogen daily capacities for alternative hydrogen production technologies (see Appendix 1 and 2 for a detailed list of sources).

Table 2 shows the common set of assumptions used here to derive hydrogen production cost estimates. The hydrogen production cost of the technologies reported in Appendix 1 and Appendix 2 was calculated using these assumptions, based on its efficiency, capital cost and O&M cost. All calculations in this report are based on higher heating values (HHV).

Table 2: Assumptions for calculation of hydrogen production costs.

Natural gas price	3.1 US\$(2000)/GJ (HHV basis)
Coal price	1.3 US\$(2000)/GJ (HHV basis)
Annual capital charge rate	0.15 annual interest rate 14%, plant life 20 years
Capacity factor	0.90 for gas-fired plants
	0.80 for coal-fired plants
Electricity price	40 US\$ mills (2000) /kWh for purchasing and selling
CO ₂ disposal cost	5.0 US\$(2000)/tCO ₂

Notice that in the two system configurations examined here, a small amount of electricity is produced and we assume it to be sold to the network. However, the amount is so small that we distinguish these systems from co-production cases which will be analyzed below in section 3.2. The price of purchased electricity is assumed to be equal to that of sold electricity. The value assumed here is 40 US\$ mills per kilowatt-hour (mills/kWh). The same electricity price is assumed for the cases with carbon capture.

Under our assumptions, the CO₂ that is separated from the hydrogen plant is compressed to supercritical pressures for pipeline transportation. We include the costs of CO₂ compression as well as CO₂ capture into the plant investment costs. In the cases where CO₂ compression is not taken into account in the literature, investment costs and electricity consumption were adjusted according to the assumptions described in the footnote of Appendix 1.

Following Kreutz *et al.* (2002), it is assumed that the costs of CO₂ transport and storage are 5 US\$/tCO₂, which corresponds to a 100-km pipeline and a 2-km deep injection well. This aggregate estimate is in line with the ranges reported by Freund *et al.* (2003), who give 1-3 US\$/tCO₂ as a plausible range for costs of storing CO₂ in deep saline aquifers or depleted oil/gas fields and a likely range of 1-3 US\$/tCO₂/100 km for transportation of captured CO₂ from sources to reservoirs. It should be noticed that many uncertainties still exist regarding these figures.

Figure 6 presents the resulting estimates for hydrogen production costs. The ranges reflect the dispersion of estimates in the literature and dots in the middle of the bars present the average values. As mentioned above, these costs include CO₂ compression, transportation and storage for the cases with CO₂ capture. Figure 7 presents a more detailed breakdown of these cost estimates, where the average values of investment costs, O&M costs, efficiencies, CO₂ capture efficiencies were used for this calculation. Notice that the costs for electricity presented in Figure 7 represent the net difference of electricity consumed and generated by the process. As mentioned above, in coal-based cases, a small amount of excess electricity is produced and sold to the network.

As illustrated in these figures, steam reforming of natural gas still constitutes the most cost-effective pathway for hydrogen production. However, coal gasification could also be an attractive possibility. Under the assumptions here, the cost of hydrogen production from coal gasification using the conventional PSA system would be approximately 7 US\$/GJ (HHV). Including CO₂ capture will increase the costs to approximately 9 US\$/GJ (HHV). The membrane-based system already including carbon capture could provide somewhat lower production costs at about 7.5 US\$/GJ (HHV).

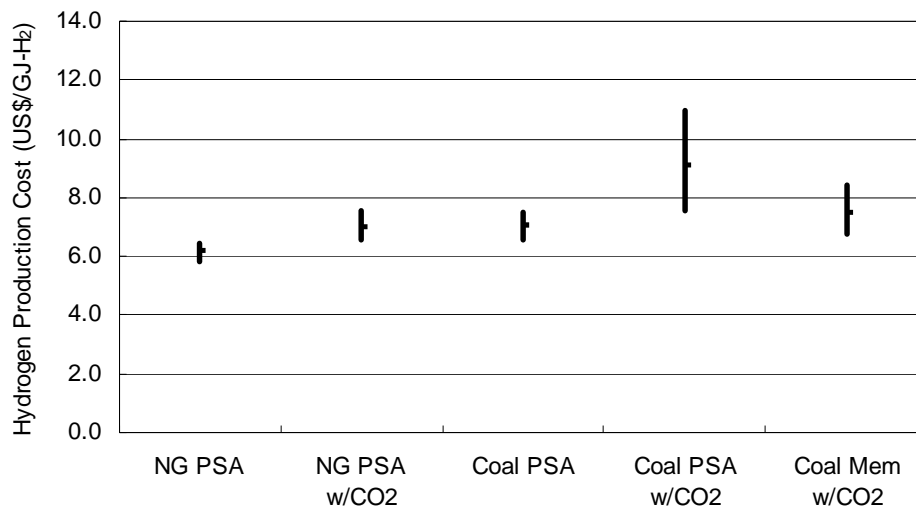


Figure 6: Estimated production costs of hydrogen by the alternative hydrogen production systems with and without CO₂ capture. The ranges reflect the dispersion of estimates in the literature and dots in the middle of the bars present the average values. For the case with CO₂ capture, costs of CO₂ compression, transportation and storage are included.

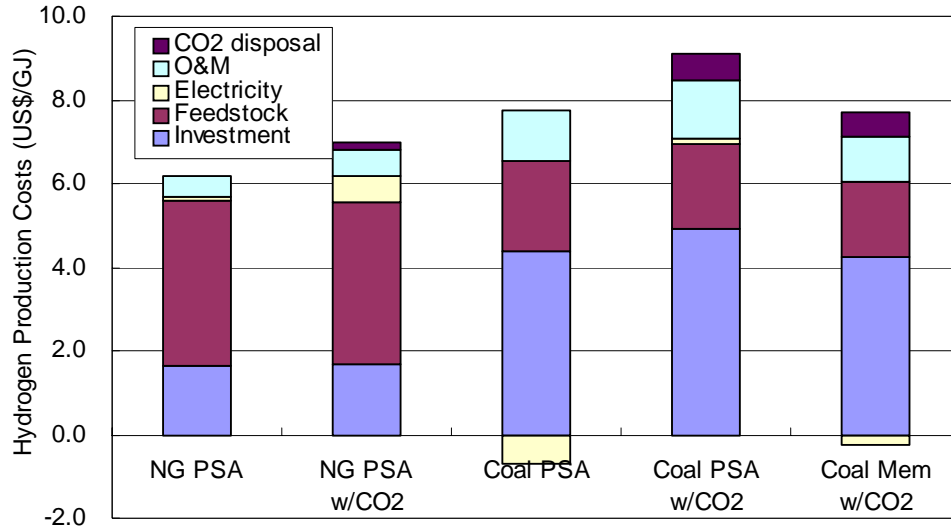


Figure 7: Hydrogen production costs breakdown, for alternative hydrogen production systems from natural gas and coal, with and without CO₂ capture. They are disaggregated into investment costs, feed stock costs, electricity costs (or revenue by selling residual electricity), O&M costs and CO₂ disposal costs, which include CO₂ transportation and storage costs.

3.1.3. CO₂ emission comparison

Figure 8 presents the hydrogen production costs (US\$/GJ) of the different alternatives together with the resulting CO₂ emissions per unit of product (tCO₂/GJ hydrogen). Clearly, since coal is a more carbon-intensive feedstock, the coal gasification process produces much higher carbon emissions per unit of hydrogen. With carbon capture, however, remaining emissions from both coal and gas-based processes become similar.

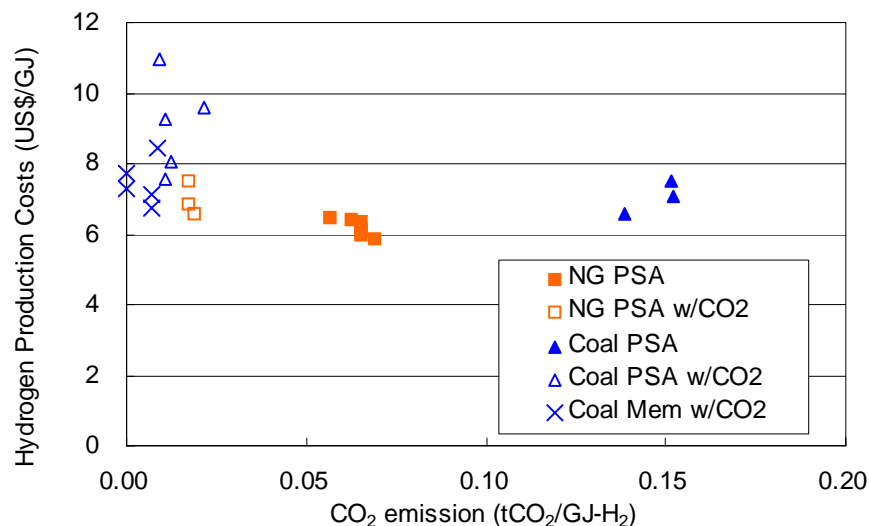


Figure 8: Estimated hydrogen production costs versus CO₂ emissions per unit of hydrogen, for alternative hydrogen production systems from natural gas and coal with and without CO₂ capture.

Here we estimate the carbon emission reduction costs for these hydrogen production technologies, using the following expression.

$$C_e = \frac{C_o - C_r}{E_r - E_o}$$

Where

C_e : carbon emission reduction cost (US\$/tC)

C_o : hydrogen cost of mitigation option (US\$/GJ)

C_r : hydrogen cost of reference system (US\$/GJ)

E_o : carbon emissions of mitigation option (tC/GJ)

E_r : carbon emissions of reference system (tC/GJ)

For the coal-fired systems, the conventional PSA-based coal gasification system without CO₂ capture (Coal PSA) is chosen as the reference system for this calculation. The reference for the natural-gas-based system is the SMR+PSA system without carbon capture. The estimation is performed using the average values of the estimated hydrogen production costs and those of CO₂ emission per unit of hydrogen. Table 3 shows the average values used for calculation and the resulting mitigation costs.

Table 3: Carbon emission reduction costs of the alternative hydrogen production technologies with CO₂ capture. For the calculation, the conventional plants without carbon capture are selected as a reference system, i.e. Coal PSA for coal-based systems and NG PSA for gas-based systems.

Technology name	Estimated hydrogen production cost (average) US\$/GJ-H ₂	CO ₂ emission (average) tCO ₂ /GJ-H ₂	Carbon emission reduction cost US\$/tC
[Ref.] Natural gas SMR + PSA Without CO ₂ capture (NG PSA)	6.2	0.064	-
Natural gas SMR + PSA With CO ₂ capture (NG PSA w/ CO ₂)	7.0	0.018	65
[Ref.] Coal Gasification + PSA Without CO ₂ capture (Coal PSA)	7.0	0.147	-
Coal Gasification + PSA With CO ₂ capture (Coal PSA w/ CO ₂)	9.1	0.013	56
Coal Gasification + HSMR With CO ₂ capture (Coal Mem w/ CO ₂)	7.6	0.004	15

Incorporating carbon capture into the conventional PSA-based coal gasification system would result in a mitigation cost of 56 US\$/tC equivalent. A cheaper alternative is that of changing to the advanced membrane-based system. This option results in an implicit mitigation cost of 15 US\$/tC.

The case of the gas-fired, PSA-based steam methane reforming system (NG PSA) is also presented here for comparison. The mitigation costs are computed with reference to the plant without carbon capture. Under the assumptions here, incorporating carbon capture into the SMR plant results in a CO₂ mitigation cost of 65 US\$/tC.

The gas-based steam methane reforming process constitutes a cheaper and less carbon-intensive alternative for hydrogen production than the coal-based gasification process. However, coal represents a more abundant and cheaper resource and could be the feedstock of choice for regions without access to low-cost natural gas. Both technologies could play a major role in a “hydrogen economy”, particularly in its initial phase that would most likely be fossil-based. If combined with CO₂ capture and storage, provided the above-mentioned unresolved issues could be addressed, coal-based hydrogen could be an important transition option towards a more sustainable energy global system in the long term.

Moreover, emerging technologies could make coal-based hydrogen production, and CO₂ separation thereof, more cost-effective, flexible and efficient in the future. Specifically, although still in their infancy, membrane-based hydrogen production systems appear to be promising.

3.2. Co-production of hydrogen and electricity

As mentioned above, energyplexes enable poly-generation strategies. One of the possibilities entails the co-production of hydrogen and electricity. Both are premium-quality, carbon-free, energy carriers with a wide range of applications. They could play preponderant and complementary roles in meeting energy needs in the long term particularly if a low-emissions global energy system is to be reached (Ogden, 1999; Barreto *et al.*, 2003; Edmonds, 2001). Being “blind” to their sources, a diversified portfolio of fossil and non-fossil primary resources can be used to produce them. This characteristic makes these two energy carriers attractive for facilitating a transition to a sustainable energy supply system because, while being compatible with the existing structure, they could enable the introduction of carbon-free primary sources and/or facilitate carbon capture and storage from carbon-intensive sources later on.

In the long term, attractive opportunities may be created for facilities where hydrogen and electricity are co-produced, in particular if a large-scale “hydrogen+electricity economy” emerges. Co-producing hydrogen and electricity may have several advantages. The efficiency of the integrated process could be higher and capital costs could be reduced. Also, co-production could be a strategy for improving the economics of hydrogen production and stimulate its penetration. Depending on the value at which the co-product electricity can be sold to the network, the hydrogen production costs could be reduced. In addition, centralized co-production plants may facilitate the capture of carbon in case it is necessary.

This requires the development and deployment of technologies that transform a primary resource into a suitable form that enables obtaining a flexible mix of both products. Syngas production systems offer attractive possibilities in this respect and one of the technologies that could play a key role is coal gasification. In this section, we examine the co-production of hydrogen and electricity by different coal gasification systems.

3.2.1. Co-production systems

As before, we consider a conventional system with PSA-based hydrogen separation and two membrane-based systems. For each system we have examined only the case with carbon capture. Our calculations are based on the techno-economic characteristics reported in Gray and Tomlinson (2002). In the first case (Case 1), i.e., the conventional system, the syngas stream from the gasifier is used as input to a shift reactor, a CO₂ removal unit and a PSA

process from where the hydrogen is recovered and the remaining mix is used as input to a combined-cycle turbine for electricity production (see Figure 9). This system configuration is similar to that of the aforementioned conventional hydrogen production system (Figure 2), except that the purge gas is compressed and burned in a combined cycle, instead of a steam turbine, to produce more electricity because the hydrogen recovery rate of PSA is lower and purge gas has a higher calorific value.

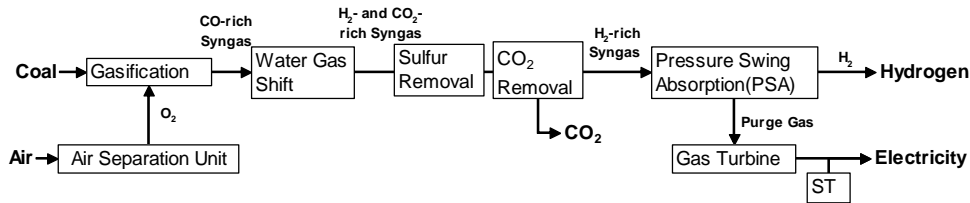


Figure 9: Co-production of hydrogen and electricity from coal with CO₂ capture using a PSA unit (Case 1).

The second case for co-production (Case 2) is similar to the membrane-based hydrogen production system shown in Figure 3, except that the hydrogen from the membrane reactor is split into two streams. The first stream corresponds to the hydrogen product and the second stream becomes the input of a hydrogen-fired combined-cycle turbine for electricity generation (see Figure 10). Notice that this configuration presupposes that the combined-cycle turbine is able to work with a hydrogen-rich gas efficiently and cleanly. Thus, an adaptation and re-design of current combined-cycle turbines could be required (Audus and Jackson, 2000).

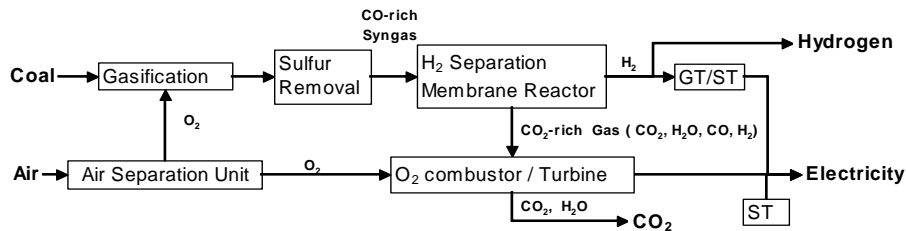


Figure 10: Co-production of hydrogen and electricity from coal with CO₂ capture using a hydrogen separation membrane reactor (Case 2)

The third case for co-production (Case 3) is a membrane-based system with a Solid Oxide Fuel Cell (SOFC) topping cycle (see Figure 11). This is a so-called hybrid system that includes the combination of a fuel cell and a gas turbine for electricity generation. It is presented here in order to highlight the possible future potential of such a system, which benefits from synergies between the component technologies to achieve higher conversion efficiencies. The system here is one of the configurations that might have higher efficiencies of electricity generation than Case 1 or Case 2, while the efficiencies of hydrogen production are almost the same.

In this system, the synthesis gas stream, which is cleaned of sulfur and particulates, is sent to the H₂-separation membrane reactor (HSMR) to be shifted and pure hydrogen is extracted. The stream leaving the HSMR, which consists of carbon monoxide, hydrogen, and carbon dioxide, is sent to the anode of the SOFC to produce electricity. The anode exhaust gas is burned with oxygen in a gas turbine for power generation. The effluent gas, which contains

only carbon dioxide and water, is dried and compressed for sequestration, after cooled in a HRSG for steam generation. The high-temperature cathode exhaust gas is sent to a turbine for electricity production followed by an HRSG for steam generation. Steam from the HRSG produces some extra electricity.

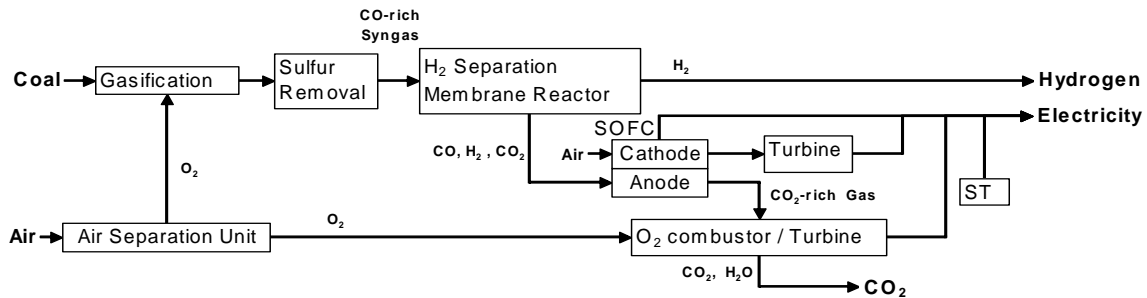


Figure 11: Co-production of hydrogen and electricity from coal with CO₂ capture using a membrane reactor and SOFC (Case 3).

3.2.2. Economic analysis of co-production systems

Using these system configurations, we illustrate the effect of the co-production of hydrogen and electricity on the production costs of hydrogen. Table 4 summarizes the figures for performance and costs used in this analysis, which are derived from Gray and Tomlinson (2002). Compared to the only-hydrogen production systems (Table 1), a much higher amount of electricity, which ranges between 56 and 83% of co-produced hydrogen, is generated in the co-production systems (Table 4). The investment cost of Case 3 is based on a SOFC stack cost of US\$400/kW.

Table 4: Summary of co-production systems of hydrogen and electricity from coal.

	Hydrogen Capacity Million Nm ³ - H ₂ /day	Feedstock Ratio ^a GJ/GJ-H ₂	Electricity Output Ratio ^a GJ _e /GJ-H ₂	CO ₂ Capture Efficiency %	Investment cost Million US\$(2000)	O&M cost Million US\$(2000)/year
Case 1	4.2	2.89	0.56	95	970	55
Case 2	4.2	2.89	0.65	100	970	50
Case 3	4.3	2.94	0.83	95	1070	60

^a For the definition of these factors see the corresponding note in Table 1.

Since part of the feedstock is now used to produce electricity in the co-production systems, the efficiency of hydrogen production is smaller in the co-production systems as compared to the respective hydrogen-only production systems.

For co-production systems, hydrogen production costs are highly affected by the value at which co-produced electricity can be sold. Moreover, this selling price of electricity depends on the price of the feedstock for electricity production. In order to illustrate this dependence, we make some assumptions for the selling price of electricity co-produced with hydrogen. Following Gray and Tomlinson (2001), these assumptions are based on the electricity generation costs of NGCC and IGCC power plants as described below.

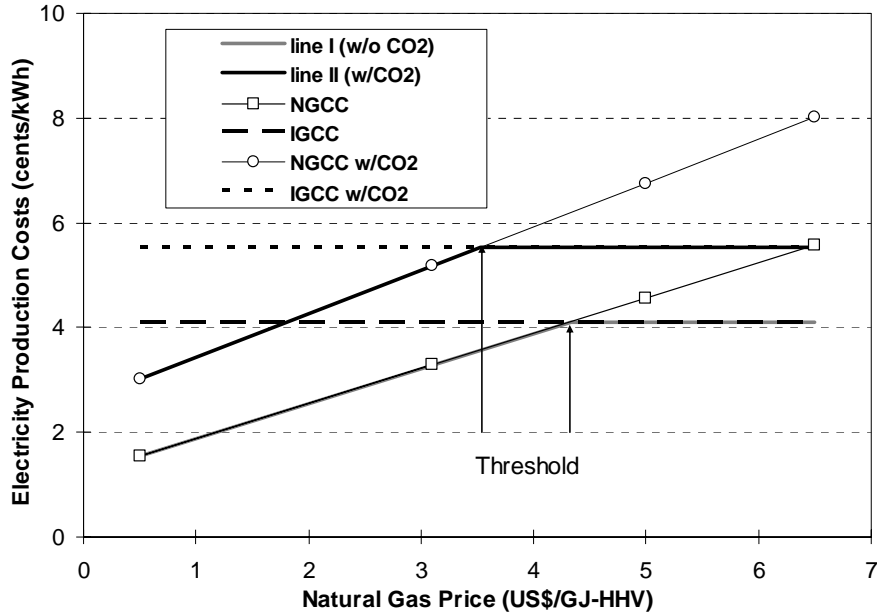


Figure 12: Relationship of electricity production costs to natural gas price, for a NGCC and a IGCC power plant with and without CO₂ capture, at the coal price of 1.3 US\$/GJ. In estimation of co-production systems without CO₂ capture, it is assumed that co-produced electricity is sold at the price that Line I gives as a function of natural gas price. For the case with CO₂ capture, the Line II is used.

Figure 12 presents the electricity generation costs for the Natural Gas Combined Cycle (NGCC) and Integrated Gasification Combined Cycle technologies (with and without carbon capture) as a function of the price of natural gas.³ The electricity generation costs from these reference gas-fired NGCC plants increase linearly as the price of natural gas increases, while those of coal-fired IGCC plants remain unchanged (it is assumed that coal prices remain constant at 1.3 US\$/GJ). As shown, NGCC power plants are more economic than IGCC plants for a wide range of gas prices. Under the assumptions here, without carbon capture, the electricity generation costs of NGCC plants reach the IGCC “threshold” when the gas price raises above approximately 4.3 US\$/GJ. With carbon capture, the interception occurs at a lower price of approximately 3.5 US\$/GJ.

Here, we use the generation costs of this NGCC plant, which increases linearly with the gas price, as a reference for the electricity price. However, at sufficiently high natural gas prices, other electricity production technologies would become more attractive. Thus, on the rationale that the price at which electricity can be sold would correspond to that of the available lowest-cost plant, we have set a limit for this linear increase. Such a limit has been

³ Based on EPRI 2000, investment costs, O&M costs, thermal efficiencies and CO₂ emissions are taken as follows;

NGCC	:502 US\$/kW, 0.26 cents/kWh, 53.6% (HHV basis), 338 kg CO ₂ /MWh
NGCC w/CO ₂	:943 US\$/kW, 0.64 cents/kWh, 43.3% (HHV basis) , 40 kg CO ₂ /MWh
IGCC	:1266 US\$/kW, 0.65 cents/kWh, 43.1% (HHV basis) , 718 kg CO ₂ /MWh
IGCC w/CO ₂	:1648 US\$/kW, 0.78 cents/kWh, 37.0% (HHV basis) , 73 kg CO ₂ /MWh

For all plants, it is assumed that the annual capital charge rate is 0.15, capacity factor 0.8, coal price 1.3 US\$/GJ (HHV basis) and CO₂ disposal cost 5 US\$/tCO₂.

chosen as the “threshold” value where NGCC generation costs become equal to those of a coal-fired IGCC power plant (see Figure 12), provided that coal prices remain constant.

In Figure 12, the resulting relationships representing the dependence of electricity generation costs on the prices of natural gas are labeled as “Line I” for the case without carbon capture and “Line II” for the case with carbon capture. In this section, we examine only the cases with carbon capture (Line II).

On the basis of these assumptions, it is equivalent to illustrate the dependence of the production costs of hydrogen on the price of natural gas, which on its turn determines the price at which the co-produced electricity can be sold. Figure 13 presents the sensitivity of the production costs of hydrogen to the price of natural gas. Hydrogen production costs were calculated based on the assumptions in Table 2, except for prices of natural gas and electricity.

The cases with only hydrogen production are also shown for comparison. As mentioned above, in these cases some electricity is produced and sold to the network. However, such an amount is too small to produce significant changes in hydrogen production costs.

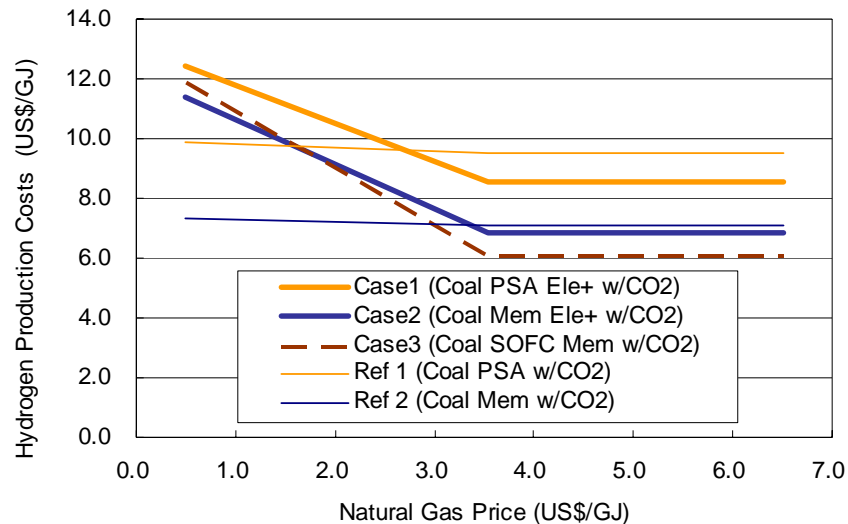


Figure 13: Estimated hydrogen production costs in coal-based co-production plants as a function of natural gas price. The cases with only hydrogen production are also shown for comparison (Ref 1 and Ref 2).

In contrast, in the co-production cases (Cases 1 to 3), hydrogen production costs are strongly influenced by the electricity-selling price. With higher costs of natural gas, the electricity generation costs increase and, therefore, the credits for sales of the co-product electricity in the joint production facility become larger. Consequently, the production costs of hydrogen are linearly reduced. Once the natural-gas price reaches the level where the IGCC plant becomes more competitive than the NGCC plant, the production costs of hydrogen become insensitive to further increases.

The resulting hydrogen production costs in the co-production schemes based on membrane reactors (Case 2, Case 3) are considerably lower than those in the co-production scheme based in the conventional PSA unit (Case 1). In addition, in these illustrative calculations, the co-production system that includes both a membrane-reactor and an SOFC “topping

cycle” (Case 3) appears to have the largest potential to achieve costs reductions in the production of hydrogen.

Figure 13 suggests that co-production systems might be attractive, as compared to the respective hydrogen-only production systems, when the price of natural gas rises above a given level. Still, under the assumptions made here, the benefits of selling the co-product electricity will increase only up to the point where the above-mentioned “threshold” for the price of natural gas, and therefore the electricity price, is reached.

However, the magnitude of the reduction of hydrogen production costs in the co-production mode relative to the respective hydrogen-only system differs significantly between the alternative configurations. The benefits of co-production in Case 2, i.e., the membrane-based system, appear small, while those of Case 1 are larger.

In order to understand this behavior it is important to compare the configurations in Case 1 and Case 2 (describe in Table 4 above) and the respective hydrogen-only systems (Ref 1 and Ref 2). It can be noticed that the advanced HSMR-based co-production system (Case 2) has a higher electricity-to-H₂ ratio than the conventional PSA-based co-production system (Case 1). However, the reduction of hydrogen-production efficiency relative to the respective hydrogen-only production system is lower for the PSA-based system (Case 1) than for the HSMR-based system (Case 2). For the sake of clarity, these two aspects are illustrated in the values summarized in Table 5.

Table 5: Comparison of feedstock ratio and electricity-to-H₂ ratio for the co-production systems in Case 1 and Case 2 and their respective hydrogen-only production systems.

	H ₂ -Only		H ₂ and Electricity Co-production	
	PSA (Ref 1)	HSMR (Ref 2)	PSA (Case 1)	HSMR (Case 2)
Feedstock ratio ^a (GJ/GJ H ₂)	1.69	1.40	2.89	2.89
Electricity output (H ₂) ratio (GJ/GJ H ₂)	0.037	0.038	0.56	0.65

^a For the definition of these factors see the corresponding note in Table 1.

The implications of these two factors are as follows. On the one hand, a higher electricity-to-H₂ ratio results in a faster reduction of the H₂ production costs as the selling price of the co-product electricity (reflected by the price of natural gas in our analysis) is increased. This is because a larger amount of electricity is produced and sold and, thus, credits due to sales of the co-product electricity are larger per unit of hydrogen in Case 2 as compared to Case 1. That is, as shown in the Figure 13, the downward slope of the curve in the co-production Case 2 is higher than in Case 1.

On the other hand, a lower relative reduction of hydrogen-production efficiency brings a smaller increase in hydrogen production costs. Now, given that the relative reduction of hydrogen-production efficiency in the PSA-based co-production Case 1 is lower than in Case 2, the difference between the hydrogen production costs of Case 1 and its respective H₂-only case (Ref 1) at the very low natural gas prices is smaller than between Case 2 and its respective H₂-only case (Ref 2). Therefore, and despite the fact that its downward slope is less steep, the price of natural gas (i.e., the electricity-selling price), at which the hydrogen production costs becomes lower than those of the hydrogen-only case, are lower in Case 1 than in Case 2. Since the natural-gas price “threshold” at which the reduction in hydrogen production costs ceases is the same for both cases, the benefits of co-production are larger for Case 1.

4. Co-production of Liquid Fuels and Electricity from Coal

An alternative poly-generation strategy based on coal gasification systems is the co-production of electricity and synthetic liquid fuels. Increasing environmental concerns leading to the implementation of more stringent specifications for fuels, especially in the transport sector, could stimulate liquid synfuels penetration. In addition, liquid-synfuels production from indigenous resources, such as coal, could be an attractive option for countries reluctant to excessively relying on imported oil, which has widely-known associated geopolitical instabilities. Thus, their share of the global final-energy mix could augment substantially in the future.

A number of synthetic fuels have been highlighted as alternatives to the currently dominating oil products in the transportation system. Among others, ethanol, methanol, Dimethyl-ether (DME), Fischer-Tropsch (F-T) liquids (diesel, gasoline) and hydrogen have been considered as potential candidates. While hydrogen is regarded as an attractive option for the long term, clean liquid synfuels could have applications in a nearer time horizon. They could contribute in addressing air pollution problems resulting from the growing use of oil products in the transportation sector (Williams, 2001). Also, they could play a role in reducing greenhouse gas emissions. On the one hand, they can be used in highly efficient end-use technologies such as advanced internal combustion engines, hybrid vehicles and, later on, fuel cells. On the other hand, syngas-based production of liquid synfuels could enable carbon capture and storage.

Clean liquid synfuels could be instrumental in a transition of the global transportation sector, away from its today's heavy reliance on oil products, towards a more diversified, cleaner and balanced mix of energy carriers meeting mobility and freight needs. Moreover, liquid synfuels could operate as "bridging" energy carriers in a long-term transition towards an energy system where hydrogen and electricity play the main roles.

As mentioned above, the co-production of electricity and liquid synfuels could have advantages in comparison to synfuel-dedicated plants. In addition, since both electricity and liquid synfuels would be more compatible with the existing infrastructure than, for instance, hydrogen, this scheme could provide an attractive strategy for the early introduction of "energyplexes" into the marketplace. In the long term, if demand for hydrogen grows, these facilities could be adapted to accommodate hydrogen as an additional product or shift to a scheme where only hydrogen and electricity are co-produced.

Here, we highlight two illustrative configurations. The first system considered here is a coal gasification plant that co-produces electricity and Fischer-Tropsch (F-T) liquids. The second system under examination here co-produces electricity and methanol.

4.1. Co-production of electricity and Fischer-Tropsch liquids

The first system considered here is a coal gasification plant that co-produces electricity and Fischer-Tropsch (F-T) liquid fuels. The so-called Fischer-Tropsch synthesis reactor allows converting syngas into a mixture of various paraffinic and olefinic hydrocarbons. Among others, clean diesel and gasoline can be obtained, which do not contain sulfur or nitrogen, have very low contents of aromatics and exhibit a high cetane number (NETL, 2001).⁴

⁴ The Cetane number measures the ignition quality of a diesel fuel. A higher Cetane number implies the higher capacity of a fuel to auto-ignite.

Although this technology has been known for several decades, commercial applications have been limited so far. However, clean F-T liquids could offer possibilities for compliance with stricter environmental rules in the transportation sector, already being implemented today or to be enforced in the short term. In particular, they could be used as a blending stock to produce low-sulfur gasoline and diesel, which are necessary for the adequate functioning of the emission control technologies that could reduce NO_x emissions from current vehicles to very low levels. In the medium term, F-T liquids could play an important “bridging” role in a transition towards cleaner and more convenient transportation fuels and technologies. Specifically, they could enable a more efficient and environmentally compatible use of advanced internal combustion engines.

In a co-production mode, the purge gas from the F-T synthesis reactor, which is the gas stream that did not react during the F-T process, can be used as a supplementary input to the electricity generation process, thus increasing the overall efficiency (NETL, 2001). Also, the co-production scheme facilitates the capture of CO₂ as compared to an F-T-only process.

The technical and economic characteristics of the process illustrated here have been adopted from Gray and Tomlinson (2001). As before, we consider cases with and without carbon capture. Figure 14 presents the block flow diagram of the F-T liquid co-production system, and Table 6 summarizes performances and costs used for this analysis.

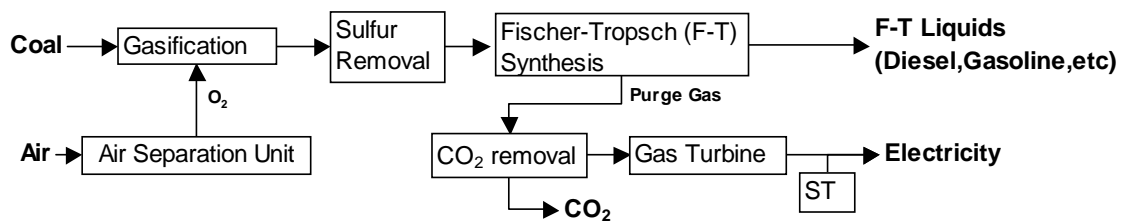


Figure 14: Co-production of F-T liquids and electricity from coal with CO₂ capture. For the system without CO₂ capture, the block of CO₂ removal is to be omitted.

Table 6: Summary of co-production systems of F-T liquids and electricity from coal.

	F-T liquid Capacity	Feedstock Ratio ^a	Electricity Output Ratio ^a	CO ₂ Capture Efficiency	Investment cost	O&M cost
	TJ/day	GJ/GJ-F-T	GJ _e /GJ-F-T	%	Million US\$	Million US\$/year
Without CO ₂ capture	190	2.2	0.32	0	2200	118
With CO ₂ capture	190	2.2	0.23	90	2290	123

^a See note on the items in Table 1 that correspond to these items.

The purge gas from the F-T unit, which contains the unconverted syngas, methane, ethane, ethylene, and carbon dioxide, is sent to a gas turbine combustor, followed by the heat recovery steam generator. For the CO₂ capture case, the carbon dioxide is removed using an amine system from the purge gas before it is combusted. Approximately 58% of the carbon dioxide in the feedstock is captured. 6% is emitted to the atmosphere and about 36% remains in the F-T product.

The economics of F-T liquid fuels production in the co-production plant are significantly affected by the price at which the co-product electricity can be sold to the network. In order

to illustrate this dependence, we have made some assumptions for the price of electricity, following Gray and Tomlinson (2001), which were described above for the hydrogen and electricity co-production case.

As mentioned above, on the basis of these assumptions it is equivalent to illustrate the dependence of the production costs of F-T liquids on the price of natural gas, which determines the selling price of the co-produced electricity. Figure 15 presents the sensitivity of the production costs of F-T liquids to the price of natural gas. Cases with and without CO₂ capture are shown for different levels of coal prices. F-T liquid production costs were calculated on the assumptions in Table 2, except for prices of natural gas and electricity.

As before, with higher costs of natural gas, the price at which the co-product electricity can be sold becomes larger and, therefore, the production costs of F-T liquids are reduced. Once the natural gas price reaches the “threshold” price, the production costs of F-T liquids become insensitive to further increases. Also, as expected, lower coal costs drive to lower production costs of F-T liquids.

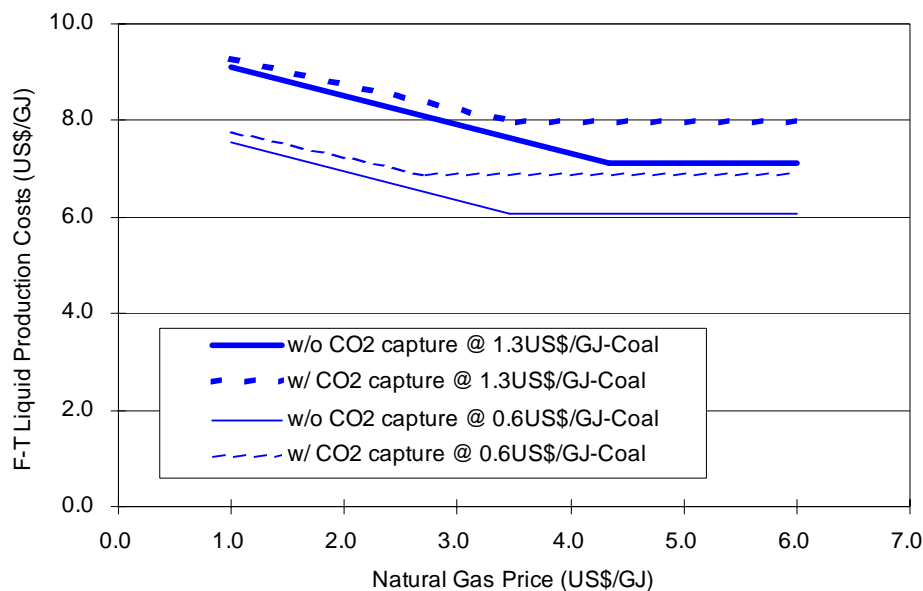


Figure 15: Estimated production costs of F-T liquids in a coal-fired co-production plant as a function of natural gas price. Cases with and without CO₂ capture are shown for different levels of coal prices, 1.3 US\$/GJ and 0.6 US\$/GJ.

We also examine the CO₂ emissions from the co-production of F-T liquids and electricity from coal. Figure 16 presents the production costs of F-T liquids (US\$/GJ) together with the corresponding CO₂ emissions per unit of product (tCO₂/GJ). The emissions in both the fuel production process and end-use combustion are accounted for. For this punctual estimate, it is assumed that the co-product electricity can be sold at a price that is equivalent to the electricity generation cost of an IGCC plant.⁵ When computing the CO₂ emissions of these systems those of the corresponding power plants, i.e. IGCC with or without CO₂, are subtracted according to the amount of electricity sold. Two different levels of coal prices

⁵ In the cases where the co-production facility is equipped with carbon capture, the price of electricity is also that of the IGCC plant with carbon capture.

were examined here. For reference purposes, the production costs of F-T liquids from coal with no co-product⁶, F-T liquids from remote natural gas (with and without CO₂ capture)⁷, and diesel from crude oil⁸ are also shown.

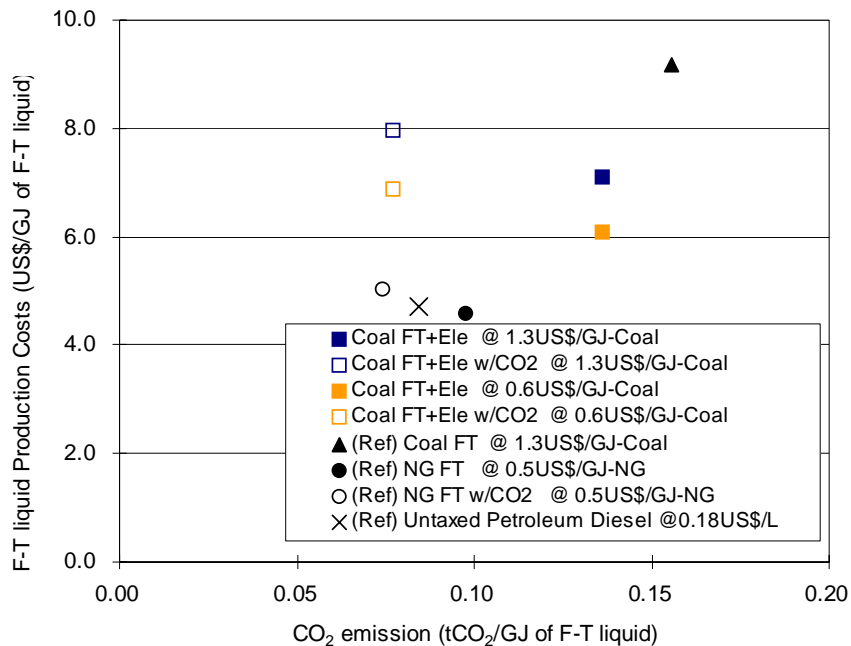


Figure 16: F-T liquids production costs vs. CO₂ emissions for F-T liquids and electricity co-production from coal (the symbol “w/CO₂” stands for cases with CO₂ capture). Cases with and without CO₂ capture are shown for different levels of coal prices, 1.3 US\$/GJ and 0.6 US\$/GJ. For reference purposes, plots of F-T liquids from coal with no co-product, F-T liquids from remote natural gas with and without CO₂ capture and diesel from crude oil are also shown. The emissions in both the fuel production process and end-use combustion are accounted for.

As illustrated, both the production cost and the CO₂ emissions of a co-production facility are lower than those of a facility dedicated only to the production of F-T liquids. But, even in a co-production facility where credits are received for the electricity being sold, F-T liquids from coal appear considerably more expensive than petroleum diesel or F-T liquids from low-price (remote) natural gas. Moreover, without CO₂ capture, their production results much more carbon-intensive.

6 Based on Bechtel Corporation (1998), investment cost of 3245 million US\$ and thermal efficiency of 63.6% (HHV basis) are assumed for a plant of 290 TJ of F-T liquids per day. It is assumed that O&M cost is 4% of investment/year, coal price is 1.3 US\$/GJ, the annual capital charge rate is 0.15, capacity factor 0.8 and CO₂ disposal cost 5 US\$/tCO₂.

7 Based on Marsh *et al.* (2002), investment costs, O&M costs, thermal efficiencies and CO₂ emissions of F-T liquid plant from natural gas, which produces 57 TJ of F-T liquids per day, are assumed as follows;

NG F-T :346 million US\$, 72.1 million US\$/year, 53.2% (HHV basis), 20.2 tC/h

NG F-T w/CO₂ :389 million US\$, 83.1 million US\$/year, 52.6% (HHV basis), 6.0 tC/h

It is assumed that remote natural gas price is 0.5 US\$/GJ, the annual capital charge rate is 0.15, capacity factor 0.9 and CO₂ disposal cost 5 US\$/t CO₂.

8 It is assumed the price of diesel from crude oil is 0.18 US\$/liter as an average untaxed retail price for November in 1998 (Metschies, 1999) and CO₂ emission during refinery process is 15.3 kg CO₂/GJ of diesel (Marano and Ciferno, 2001).

With CO₂ capture in place, the costs of the F-T liquids are increased but not significantly and the CO₂ emissions lie in the range of those of petroleum diesel production. Thus, the introduction of F-T liquids from coal, at least with today's efficiencies, would most likely not lead to a reduction in carbon emissions as compared to oil products or natural gas based F-T liquids. However, as mentioned above, they could contribute to reduce the sulfur content of transportation fuels and, subsequently, in enabling the operation of the technologies necessary for the reduction of NO_x emissions from mobile sources, thus bringing air quality benefits. If the credits for less pollution would be taken into account and low price feedstock could be available, F-T liquids from coal with CO₂ capture might be attractive.

4.2. Co-production of electricity and methanol

An alternative system based on syngas allows the co-production of electricity and methanol, which can be used either as a chemical feedstock or as an energy carrier. As an energy carrier, methanol has a number of potential applications. One attractive possibility is its use in fuel cells for mobile applications. Methanol can be easily reformed into hydrogen and could be more easily stored and transported than hydrogen (IEA/AFIS, 1999; Williams, 2001). Also, its use in fuel cells would be more efficient and more environmentally benign than its application in internal combustion engines. However, concerns about the toxicity risks still have to be adequately addressed.

Co-producing electricity and methanol could contribute to enhance the economics of both products. Here, we illustrate a system configuration combining the so-called Liquid Phase Methanol Process (LPMEOHTM), a relatively novel process being pursued by the US Department of Energy and several industrial partners (Air Products and Chemicals, 1998; DOE, 1999d), and an IGCC power plant.

The LPMEOHTM process, which is currently in the demonstration stage, converts syngas into methanol. This process can reach higher syngas conversion levels and has lower purification costs than conventional methanol production technologies. Also, it allows producing high-quality methanol from a wider range of syngas compositions and specifically from syngas mixtures rich in carbon monoxide.

Although it can be used as a methanol-dedicated facility, the process was initially developed to enhance IGCC power plants. An integrated system, combining an IGCC power plant and a LPMEOHTM reactor, provides additional flexibility and allows higher conversion efficiencies. It also opens the possibility for profiting from electric load variations by performing the bulk production of methanol during off-peak periods, thus allowing the gasifier to operate at full load.

The technical and economic characteristics of the process considered here are based on the analysis reported by Air Products and Chemicals (1998). Since no economic data of a methanol co-production plant with CO₂ capture could be found, we consider only the case without CO₂ capture. Figure 17 presents the block flow diagram of the methanol/electricity co-production system, and Table 7 summarizes the performance and costs of three types of co-production facilities with different values of the so-called parameter α , which corresponds to the fraction of the syngas input that is converted to methanol during the process.

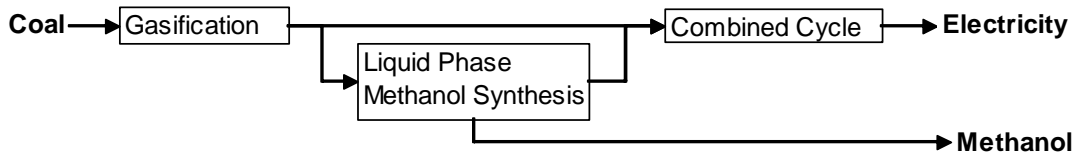


Figure 17: An integrated system combining an IGCC power plant and a LPMEOH™ reactor.

Table 7: Summary of co-production systems of methanol and electricity from coal.

Conversion Ratio α^a	Methanol Capacity	Feedstock Ratio b	Electricity Output Ratio b	CO ₂ Capture Efficiency	Investment cost	O&M cost
	TJ/day	GJ/GJ-methanol	GJ _e /GJ-methanol	%	Million US\$	Million US\$/year
0.92	9.1	1.8	0.03	0	118	5.0
0.50	9.1	3.4	0.68	0	206	6.5
0.32	9.1	5.3	1.55	0	309	10.8

^a The fraction of the syngas input that is converted to methanol during the process.

^b See note on the analysis in Table 1 that correspond to these items.

Here, we also illustrate how production costs of methanol in the co-production plant are affected by the price at which the co-product electricity is sold. As before, the assumptions on the selling price of electricity are those described in section 3.2.2 above.

Figure 18 depicts the dependence of the production costs of methanol on the price of natural gas, which, under our assumptions, determines the selling price of the co-produced electricity. Methanol production costs were calculated on the assumptions in Table 2, except for prices of electricity. Cases for different values of the parameter α are shown.

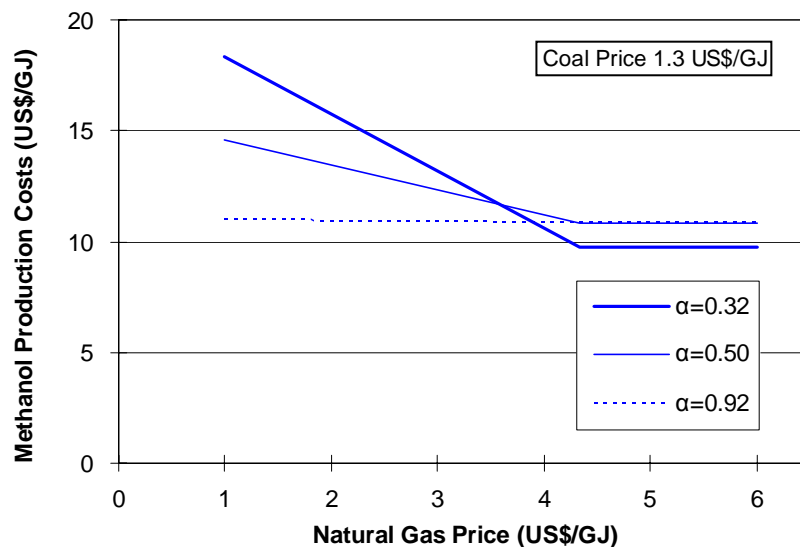


Figure 18: Methanol production costs of co-production plants from coal as a function of natural gas price. The coal price is assumed at 1.3 US\$/GJ.

As before, with higher prices of natural gas, the price at which the co-product electricity can be sold becomes larger and, therefore, the production costs of methanol are reduced. Once the natural gas price reaches the “threshold” price, the production costs of methanol become insensitive to further increases.

However, the effect depends on the amount of electricity that is co-produced. For the case with $\alpha = 0.92$, the fraction of co-produced electricity is too small as to produce any significant variations in the methanol production cost. With lower values for the parameter α (0.50, 0.32), more electricity is co-produced and the effects become more pronounced. Specifically, as α is reduced, the methanol production cost becomes higher at low prices of natural gas but it decreases with a steeper slope as gas prices increase and it reaches a lower “floor” value.

Figure 19 presents the influence of different values of the coal price on the production cost of methanol. As mentioned above, according to our assumptions, the coal price determines the “floor” that the methanol production cost can reach. As expected, with a lower price for the coal feedstock the methanol production cost is lower. Also, a lower “floor” cost for methanol can be achieved. However, the “floor” cost also is reached at a lower level of the natural gas price because the “threshold” value for the price at which the co-product electricity can be sold⁹ also becomes lower.

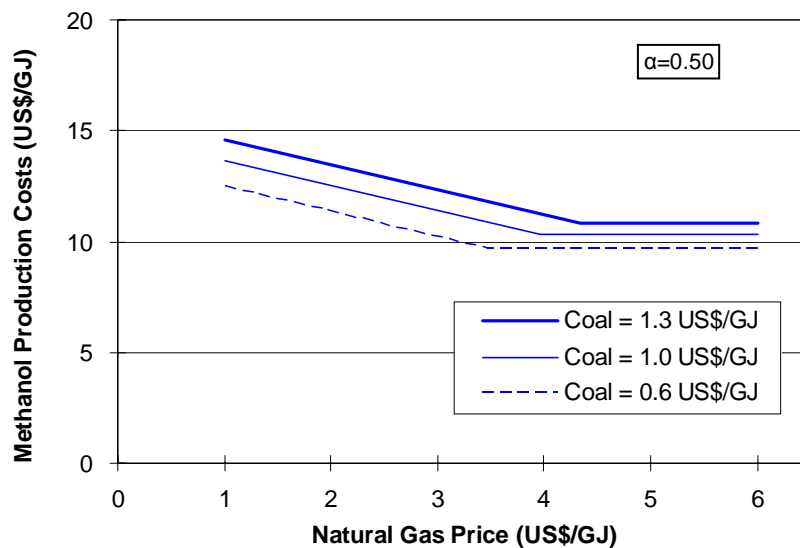


Figure 19. Methanol production costs of co-production plants from coal as a function of natural gas price for three different coal prices and the case with a parameter α of 0.5.

Figure 20 presents the resulting production costs of methanol (US\$/GJ) together with the corresponding CO₂ emissions (tCO₂/GJ). Emissions include both those from the fuel production process and the end-use combustion of the product. Figures are shown for different values of the parameter α mentioned above. It is assumed that the co-product electricity can be sold at a price that is equivalent to the electricity generation cost of an IGCC plant. In the computation of the CO₂ emissions of these systems, the emissions of the corresponding power plants, i.e., IGCC without CO₂ capture, are subtracted according to the

⁹ Here, the reader should bear in mind the assumptions described in section 3.2.2.

amount of electricity sold. For reference purposes, the production costs of methanol from natural gas with two different prices¹⁰ and of diesel from crude oil are also shown.

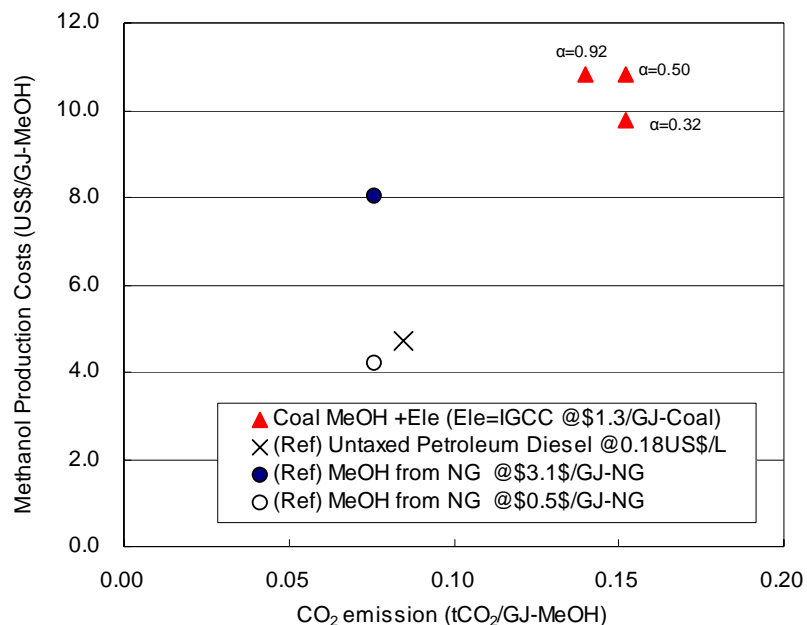


Figure 20: Estimated production costs vs. CO₂ emissions of methanol and electricity co-production from coal. Cases are shown for different values of the parameter α that corresponds to the fraction of the syngas input that is converted to methanol during the process. For reference purposes, the plots of methanol from natural gas with two different prices and of diesel from crude oil are also shown.

As illustrated, as the parameter α decreases, i.e., the amount of co-produced electricity increases, the CO₂ emissions of a co-production facility increase slightly while the methanol production cost decreases. Methanol from coal might be competitive with methanol from natural gas depending on the prices of natural gas and coal, but it still appears to be significantly more expensive than petroleum diesel. Moreover, its production is more carbon-intensive. Thus, the introduction of methanol from coal without CO₂ capture would most likely not lead to a reduction in carbon emissions as compared to oil products or natural gas based F-T liquids.

5. Conclusions

This report has examined the production of hydrogen, electricity and liquid fuels using a coal gasification process. This process could constitute a key building block of integrated energy systems, also known as “energyplexes”, based on the production of synthesis gas (syngas) and capable of having multiple products and use several feedstocks.

We have compared costs of hydrogen produced by coal gasification with CO₂ capture for two specific system configurations, a conventional system using Pressure Swing Adsorption (PSA) for hydrogen separation and a novel system using a membrane-based hydrogen

¹⁰ One of the cases considered here corresponds to a system that uses cheap natural gas from remote areas as feedstock.

separation reactor (HSMR) for the same purpose. On the basis of a literature survey, we have computed hydrogen production costs for a set of production systems under a common set of assumptions, thus obtaining both a range and mean values for the production costs. While hydrogen production costs from conventional systems are estimated at 7.5–11 US\$/GJ (HHV), those from membrane-based systems are in the range of 7–8.5 US\$/GJ (HHV). These seem to be competitive with hydrogen from natural gas steam reforming systems, which are at the present the most efficient and economical process for hydrogen production. Although still in their early R&D stage, membrane-based hydrogen production systems appear to be promising.

It should be noticed that these calculations have not considered the possible effects of technological learning (Argote and Epple, 1990; McDonald and Schramm, 2001) in reducing the production costs of hydrogen. As R&D activities continue in this field and market experience is accumulated through demonstration programs and deployment actions, significant cost reductions could take place in these systems in the future.

We have also explored three co-production strategies based on coal gasification, namely hydrogen and electricity, electricity and F-T liquids and electricity and methanol. Our assessment illustrates how co-production schemes may improve the economics of hydrogen, F-T liquids or methanol production respectively, when the co-product electricity is sold to the network. Our results suggest that, for all co-production cases examined, they might become attractive compared to the systems with no co-product electricity in the circumstance where the natural gas price, and therefore, the selling price of electricity, exceeds a “threshold” level.

In the hydrogen and electricity co-production cases with CO₂ capture considered here, we have examined both a conventional PSA-based system and membrane-based systems. Under the assumptions here, the hydrogen production costs for the conventional PSA-based system might still be higher than those of a natural-gas-based SMR system, even when receiving the benefits of the co-production scheme. In contrast, the resulting hydrogen production costs of membrane-based co-production systems might be competitive with those of a natural-gas-based system. In addition, our illustrative calculations highlight the promising potential of systems including both membrane-based hydrogen separation and turbine/fuel cell hybrid systems for electricity generation.

For the case of F-T liquids production with CO₂ capture, the credits of co-product sales also improve their economic attractiveness. Under the conditions assumed here, however, their production costs still seem higher than those of conventional systems such as petroleum-derived diesel or gasoline, which emits almost the same amount of CO₂.

Nonetheless, F-T liquids are premium products, without sulfur or nitrogen contents, that could have attractive applications, initially as blending stock for gasoline and diesel to comply with more stringent environmental regulations and, later on, as high-quality fuels that could enable the use of advanced engines. Some automakers have started to pursue activities in this direction (see e.g., Snyder *et al.*, 2000; Steiger, 2000), although mainly concentrating on F-T liquids from natural gas. Still, if cheap coal is available and credits for cleanliness of the F-T products are accounted for, coal-derived F-T liquids could be an interesting alternative in regions where natural gas is not available or expensive or where geopolitical reasons preclude an excessive reliance on imports. In supplying such market segment and possible larger markets for F-T products that could emerge later on, the coal-

based co-production scheme incorporating CO₂-capture illustrated here could be more attractive than an F-T-only production process.

As for the case of co-production of methanol and electricity, the production costs of methanol are reduced with an increasing selling price of the co-product electricity. In addition, configurations with a larger electricity/methanol ratio could lead to some further reduction in methanol production costs. However, without capture of CO₂ coal-based methanol production is significantly more carbon-intensive than methanol production from other feedstocks (e.g. natural gas) and even than oil-derived diesel fuel. Therefore, it would not provide any reduction in CO₂ emissions.

Without CO₂ capture, coal-based hydrogen and liquid fuels production exhibits comparable or even higher carbon dioxide emissions than oil-derived energy carriers used today. Thus, the incorporation of capture and storage of CO₂ appears to be an important prerequisite if the production of these energy carriers from coal is to contribute to the mitigation of CO₂ emissions.

Using these examples we have highlighted the important role that integrated energy systems, enabling poly-generation strategies, may play in the long run in the global energy supply system. Specifically, we emphasize the role of synthesis gas (or syngas) as a key energy carrier for a multi-fuel, multi-product system based on carbonaceous feedstocks. On the one hand, syngas can be obtained not only from natural gas but also from solid energy carriers like coal and biomass thus allowing their conversion into higher quality, cleaner and more flexible energy carriers. Since the different syngas production systems are similar, or at least compatible to some extent, this will facilitate the introduction of multi-fuel systems. On the other hand, syngas production allows for a flexible mix of products, i.e., electricity, hydrogen, DME, chemical, heat, CO₂ among others.

The “energyplexes” could increase the ability of energy-services companies to compete in the marketplace. They could provide them flexibility in meeting demands in different market segments while achieving lower production costs. They could also increase their robustness by reducing the risks of relying on a single feedstock. In addition, with the possibility of achieving high conversion efficiencies and low pollutant emissions and facilitating carbon capture, they would enable them to provide high-quality energy services in a cost-effective way while meeting stringent environmental requirements, in particular those that might arise in a GHG-constrained world.

Poly-generation strategies could be launched with today’s technologies (Williams, 2001). Nonetheless, several of the technologies that would make the concept of “energyplexes” fully operational, particularly when including hydrogen production and/or carbon capture and storage, are options for the long term, which still face a number of technical and economic barriers. Thus, a number of actions are still necessary to materialize the potential of these technologies and stimulate their diffusion at the global level. For instance, a number of R&D needs have yet to be addressed. Among others, efforts must be devoted to the development of low-cost oxygen separation technologies, fuel-flexible gasification (in particular combining coal and biomass), fuel cell/turbine hybrid systems, hydrogen and CO₂ separation membranes, high-performance combustion, capture and reutilization of pollutants as useful products, etc. Also, techniques for the successful integration of the component subsystems should be developed if the potential for higher efficiency, lower production costs and reduced environmental impacts is to be realized.

In addition, demonstration and deployment programs are necessary. While fully flexible and modular multi-fuel and multi-product integrated energy systems incorporating carbon capture are still a long-term goal, a number of component technologies are already operational. In several cases, such as the gasification technologies, actions are required to accelerate their diffusion beyond their current niche markets or ensure that expertise in other (e.g., chemical sector) industries are transferred to energy-services companies.

However, the industrial sector, and energy-services companies in particular, could perceive these technologies as (financially) risky and, therefore, may be reluctant to conduct the necessary research, development, demonstration and deployment activities (summarized as RD3, following PCAST, 1999). Therefore, government intervention is required both in conducting key long-term R&D activities and in setting up partnerships with the industry for the demonstration and deployment of these technologies.

In addition, a successful deployment strategy of integrated energy systems at the global level calls for international technology co-operation and technology transfer mechanisms, in particular between industrialized and developing countries. These activities could allow technology developers to gain access to potentially attractive markets while giving the latter the possibility to access more efficient and less environmentally damaging technologies.

Appendix 1 Hydrogen Production Technologies from Natural Gas

References	Technologies	CO ₂ separation method	Hydrogen Capacity	Feedstock Ratio ^a	Electricity Output Ratio ^b	CO ₂ Capture Efficiency	Total Capital Requirement	O&M cost	Note
			Million Nm ³ -H ₂ /day	GJ/GJ-H ₂	GJ _e /GJ-H ₂	%	\$2000/ Nm ³ H ₂ /day	\$2000/year Nm ³ H ₂ /day	
Parsons Group (2002)	SMR + PSA	-	4.2	1.35	-0.010	0	34	1.5	
Basye and Swaminathan (1997)	SMR + PSA	-	2.9	1.27	-0.010	0	48	2.4	
Basye and Swaminathan (1997)	SMR + PSA	-	2.8	1.27	n.a.	0	47	2.0	
Basye and Swaminathan (1997)	SMR + PSA	-	2.9	1.27	n.a.	0	47	1.8	
Basye and Swaminathan (1997)	SMR + PSA	-	6.7	1.27	n.a.	0	50	1.0	
Simbeck and Chang (2002)	SMR + PSA	-	1.7	1.23	-0.018	0	47	2.9	
Blok <i>et al.</i> (1997)	SMR + PSA	-	23.9	1.11 ^d	-0.029	0	47	2.7	
Williams <i>et al.</i> (1995)	SMR + PSA w/CO ₂ capture ^c	PSA	4.6	1.26	-0.038 ^c	70	53 ^c	3.1	
Parsons Group (2002)	SMR + PSA w/CO ₂ capture ^c	Chemical Absorption (Amine)	4.2	1.24	-0.024	70	38	2.1	
Blok <i>et al.</i> (1997)	SMR + PSA w/CO ₂ capture ^c	PSA	23.9	1.11 ^d	-0.040	70	49	2.7	

n.a.: Not available PSA : Pressure Swing Absorption

^a The feedstock ratio is defined as: [the energy content (HHV basis) of feedstock input to the process]/[the energy content (HHV basis) of product(hydrogen)].

^b The electricity output ratio is defined as: [the net electricity output]/[the energy content (HHV basis) of product(hydrogen)]. Negative figures mean that external input of electricity is needed.

^c It is assumed that CO₂ is compressed to supercritical pressures for pipeline transportation. In the cases where CO₂ compression is not taken into account in the literature, investment cost and electricity consumption were adjusted according to the following assumptions; Capital Cost (in 10⁶US\$) =0.351*(CAP)^{0.51117}, Electricity(in kWh/tC) =1097.5*(CAP)^{-0.1509}, where CAP is the capacity in 10³tCO₂/year, Williams (1998).

^d Feedstock used for generating steam is not included.

Appendix 2 Hydrogen Production Technologies from Coal

References	Technologies	CO ₂ separation method	Hydrogen Capacity million Nm ³ -H ₂ /day	Feedstock Ratio ^a GJ/GJ-H ₂	Electricity Output Ratio ^b GJ/GJ-H ₂	CO ₂ Capture Efficiency %	Total Capital Requirement US\$2000/ Nm ³ H ₂ /day	O&M cost US\$2000/ year - Nm ³ H ₂ /day	Note
Parsons Group (2002)	Gasification + PSA		3.2	1.54	0.081	0	112	3.6	
Williams (2001)	Gasification + PSA	-	6.9	1.69	0.075	0	115	3.9	
Gray and Tomlinson (2002)	Gasification + PSA	-	3.7	1.69	0.037	0	101	6.6	
Williams (2001)	Gasification + PSA w/CO ₂ capture ^c	Physical Absorption (Selexol)	6.9	1.70	0.052	92.0	115	3.9	
Parsons Group (2002)	Gasification + PSA w/CO ₂ capture ^c	Physical Absorption (Selexol)	3.2	1.51	0.025 ^c	92	133 ^c	3.9	
Kreutz <i>et al.</i> (2002)	Gasification + PSA w/CO ₂ capture ^c	Physical Absorption (Selexol)	6.8	1.50	0.031	92.0	108	3.7	
Gray and Tomlinson (2002)	Gasification + PSA w/CO ₂ capture ^c	Physical Absorption (Selexol)	3.4	1.86	0.054	87	126	8.0	
Williams <i>et al.</i> (1995)	Gasification + PSA w/CO ₂ capture ^c	PSA	9.0	1.29	-0.129	92	125	6.9	
Badin <i>et al.</i> (1999)	Gasification + HSMR w/CO ₂ capture ^c	O ₂ combustor	4.3	1.29	0.041 ^c	94	99 ^c	n.a.	HSMR Temp=778°C (ceramic), HPF=0.95, ATE _x
Parsons Group (2002)	Gasification + HSMR w/CO ₂ capture ^c	O ₂ combustor	4.4	1.26	-0.029 ^c	94	95 ^c	3.1	HSMR Temp=600°C (ceramic), HPF=0.95, CTE _x
Parsons Group (2002)	Gasification + HSMR w/CO ₂ capture ^c	O ₂ combustor	4.4	1.26	0.044 ^c	94	127 ^c	4.1	HSMR Temp=600°C (ceramic), HPF=0.80, CTE _x
Kreutz <i>et al.</i> (2002)	Gasification + HSMR w/CO ₂ capture ^c	O ₂ combustor	6.8	1.48	0.017	100	107	3.7	HSMR Temp=473°C (dense metal), HRF=0.85, CTE _x
Gray and Tomlinson (2002)	Gasification + HSMR w/CO ₂ capture ^c	O ₂ combustor	4.5	1.40	0.038	100	97	5.6	HSMR Temp=600°C (ceramic) HRF=0.90, CTE _x +ST

n.a.: Not available / HSMR : Hydrogen Separation Membrane Reactor / ATE_x : Advanced Turbine Expander (high temp. and pressure) / CTE_x : Conventional Turbine Expander / ST : Steam turbine
 HRF: Hydrogen Recovery Factor = Ratio of moles of permeated hydrogen through HSMR to the mole of (H₂ +CO) in the entering syngas.

^a The feedstock ratio is defined as: [the energy content (HHV basis) of feedstock input to the process]/[the energy content (HHV basis) of product(hydrogen)].

^b The electricity output ratio is defined as: [the net electricity output]/[the energy content (HHV basis) of product(hydrogen)]. Negative figures mean that external input of electricity is needed.

^c It is assumed that CO₂ is compressed to supercritical pressures for pipeline transportation. In the cases where CO₂ compression is not taken into account in the literature, investment cost and electricity consumption were adjusted according to the following assumptions; Capital Cost (in 10⁶US\$) =0.351*(CAP)^{0.51117}, Electricity(in kWh/tC) =1097.5*(CAP)^{-0.1509}, where CAP is the capacity in 10³t-CO₂/year, Williams (1998).

Acronyms and Abbreviation

ATR	auto thermal reforming
CC	combined cycle
CCS	carbon capture and storage
CO	carbon oxide
CO ₂	carbon dioxide
DME	di-methyl-ether
DOE	Department of Energy (United States)
FC	fuel cell
GT	gas turbine
F-T	Fischer-Tropsch
H ₂	hydrogen
H ₂ O	water
HHV	higher heat value
HRSG	heat recovery steam generator
HSMR	hydrogen separation membrane reactor
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
LPMEOH™	liquid phase methanol process
NETL	National Energy Technology Laboratory (United States)
NG	natural gas
NGCC	natural gas combined cycle
NO _x	nitrogen oxide
O&M	operation and maintenance
POX	partial oxidation
PSA	pressure swing adsorption
SMR	steam methane reforming
SOFC	solid oxide fuel cell
ST	steam turbine
WGS	water gas shift

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