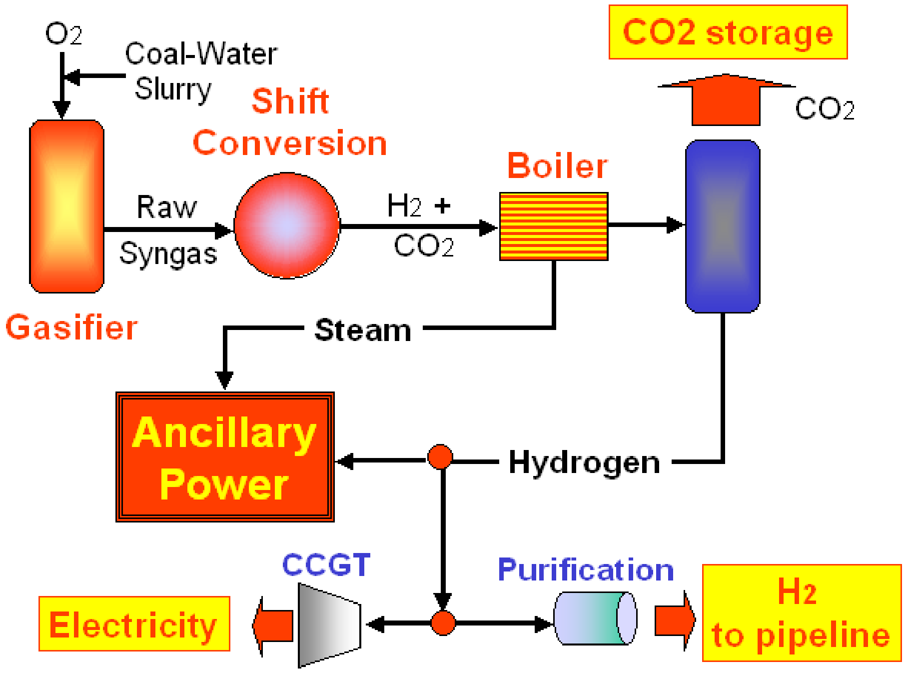
# Near-Term IGCC and Steam Reforming Processes for the Hydrogen Economy:

## The Development Issues



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# Sustainable Energy Technologies Reference and Information System (SETRIS)

The objective of SETRIS is to collect, harmonise and validate information on sustainable energy technologies and perform related techno-economic assessments to establish, in collaboration with all relevant national partners, scientific and technical reference information required for the debate on a sustainable energy strategy in an enlarged EU, and in the context of global sustainable development.

# Executive Summary

This report examines some of the key technical options for the design of HYPOGEN type plants (HYdrogenPOwerGENeration), which are intended to produce both electricity and hydrogen using fossil fuels. HYPOGEN plants will be of the clean fossil type, and capture the $CO_2$ that is formed, for subsequent storage in geological reservoirs. All of the equipment required to construct these plants, either based on steam reforming, where natural gas is the fuel, or based on gasification, where coal is used, is commercially proven. However, to produce hydrogen of an adequate purity, a number of processes, which are quite suitable for producing emission-free electricity, have to be rejected. This report follows an earlier, more general review of the subject, by the JRC entitled “The HYPOGEN Project-A JRC Perspective” published in 2005.

HYPOGEN plants will have to be able to meet the greenhouse gas emission constraints. Current targets are set by the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC). In line with this the EU is committed to reduce emissions by 8% by 2012. These plants must also be able to comply with any likely post-Kyoto requirements, in terms of $CO_2$ emissions.

The idea of HYPOGEN type processes is under discussion at the present time, and a large number of designs are under investigation. The final concept discussed in this report is unique and starts from the fact that the demand for electricity fluctuates. Even at the present time demand tends to have peaks at the beginning and end of the working day, then falling away in the middle of the night. As there is no practical means of storing electricity, this does impact on fossil fuel power plants; these are the only plants that can be relied on to meet large variations in demand. The need to meet these variations in electricity output increases the cost of power and decreases plant efficiency. With the HYPOGEN concept, proposed in this paper, the plant would be able to vary its power output from 100% electricity to 100% hydrogen, extremely rapidly. In this way the plant will operate at full capacity all the time, yet being extremely responsive to changes in demand. When the plant changes its output from electricity to hydrogen, the hydrogen will be sent to consumers via a transmission system, similar to that of the present day natural gas network.

The variation in demand from fossil plants will become more of a problem in future, as a result of the increased amount of electricity which Europe intends to generate from wind and solar sources. Owners of conventional generating plants will need to build enough capacity to cover shortages of renewable electricity, when because of calm weather, cloud cover, or fog, the power from wind farms and solar photovoltaic sources will be limited. Conversely for much of the time, when these renewable sources of electricity are active, many fossil fuel plants will be idle, producing no income.

An important consideration in the design of HYPOGEN plants is the question of hydrogen purity, as excessively high demands on purity will increase capital cost of the plant and decrease hydrogen output. In this respect the relevance of draft ISO specifications for hydrogen is discussed. It is also important that the hydrogen from the plant is produced at the highest possible pressure, 70 bar being the target for coal based HYPOGEN plants to permit long distance transmission through the pipeline network.

For a HYPOGEN plant using natural gas as a fuel, the merits of various steam reforming processes are discussed. Modern steam reforming processes have the advantage that they can produce hydrogen at a higher purity and at higher pressure than the older processes, which used a steam reforming furnace. The main drawback of the new processes is that they require an oxygen plant, which will add to capital costs. Nevertheless, in all steam reforming processes, further processing of the reformed gas is needed to increase the amount of hydrogen that is produced. These processes simultaneously capture $CO_2$ from the gas stream. The hydrogen produced would either be dispatched to consumers or burnt in a combined cycle plant, on the same site, to produce electricity when this was in demand.

Where coal is the fuel the HYPOGEN plant would be based on current IGCC (Integrated Gasifier Combined Cycle) designs where a raw gas is produced from the coal, by reactions involving steam and oxygen. In a conventional IGCC the raw gas is purified, with dust, sulphur and chlorine compounds being removed, so that the fuel gas can be used in a combined cycle gas turbine as a fuel, to produce electricity. However in a HYPOGEN-IGCC, as with steam reforming, further processing is needed, to increase the proportion of hydrogen in the gas and to facilitate the capture of carbon dioxide.

In reviewing coal based HYPOGEN plants, the report focuses on current IGCC systems and highlights how they need to be modified. A major conclusion is that air blown IGCCs are not suitable for HYPOGEN because of the difficulties in removing nitrogen from the hydrogen at the end of the process. Hence gasifiers will need to use oxygen supplied by an Air Separation Unit. The power demand for this and other key plant equipment is high, and will consume a substantial amount of electricity.

The outline design of this type of flexible HYPOGEN plant consists of either a natural gas steam reformer, or a coal fuelled gasification system that would produce a constant output of hydrogen at all times. When electricity is needed the hydrogen would be used as a fuel gas in a combined cycle gas turbine, on the same site. Any integration between the steam systems between the steam reformer or gasifier and the combined cycle would be limited to speeding up the start up of the combined cycle unit. A completely separate system of electricity generation would be needed, however, to produce the power for the ancillaries on this type of plant, which would operate at all times. Much of the energy for this would be produced using steam generated from the waste heat from the steam reformer or gasification streams.

The first HYPOGEN plant would be the focus of a European based programme to build it as a large-scale demonstrator. Preliminary design work is due to start in 2006, with the facility having the ability to evaluate innovative R&D proposals. As this report shows, this could include large scale evaluation of advanced hydrogen purification systems, fuel cells and heat exchanger concepts. HYPOGEN, if successful, should lead to the construction of a number of such plants, both in Europe and on other Continents. It will face competition from similar Japanese and American concepts, so it is important to establish at the earliest possible stage a well thought out and feasible plant specification.

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## 1. Introduction

A recent review by the Institute for Energy of the JRC examined the background to the concept of a **HYPOGEN** (**HY**drogen and **PO**wer **GEN**eration) Facility for producing hydrogen and electricity, using fossil fuels as feedstock, with the simultaneous capture and storage of the carbon dioxide produced during the process [1]. This concept was formulated as part of the recent European Initiative for Growth and within a context in which energy projections by the EU and IEA indicate the demand for electricity will continue to grow over the period 2005-2030 [2, 3].

Growth in electricity will continue as it is easy and convenient to use. Unfortunately the hour-by-hour demand for electricity fluctuates considerably. At the present time demand tends to have peaks at the beginning and end of the working day, falling away in the middle of the night. As there is no practical means of storing electricity, this does impact on fossil fuel power plants, as apart from hydropower these are the only plants that can be relied on to meet large variations in demand. Figure 1 shows how power output varies during the day over a three week period in one European country, namely Germany [4].

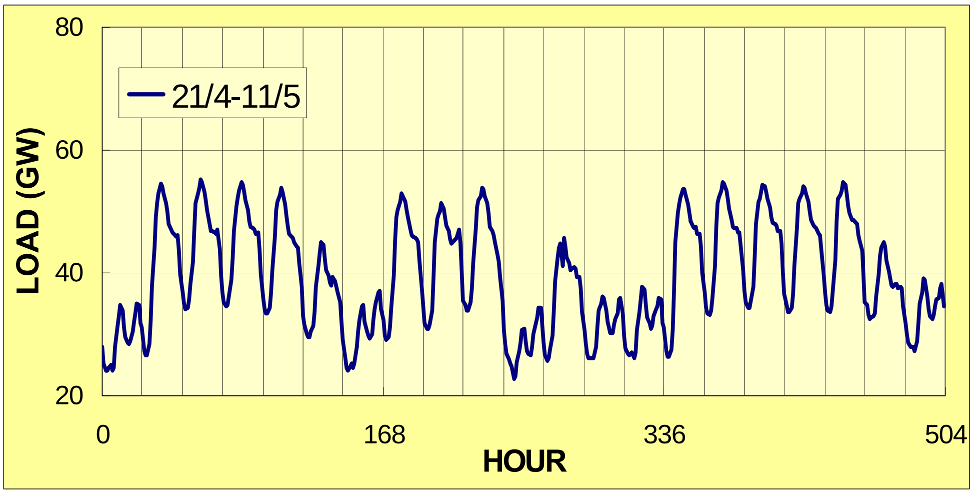


**Figure 1: Hourly power demand from fossil fuel power plants in Germany in late April / early May 2003 [4]**

These variations in demand from fossil plants are expected to increase in the future as renewable power, from wind farms and solar voltaic sources, becomes more significant. However, even today the drop in power demand at night, or at weekends, results in a large number of power plants having to be run at low loads or shut down completely. Whilst these variations are a significant cost to the owners of plant, due to the extra fuel required for restarts and increased plant maintenance, they are quite predictable. In a future dominated by renewables the variations will be much more irregular, with the need to shut many power plants down for days at a time. Clearly in some manner, future designs of fossil (and nuclear) plant will need to be designed to accept these variations.

For the plant owner, the costs associated with this unused electricity capacity will have to be covered through higher electricity prices. Alternatively, companies can risk not having sufficient generating capacity, having to impose major and frequent power blackouts, both nationally and regionally. There will be obvious large scale techno-economic and social disadvantages and penalties, either in building excess plant, or in risking widespread power cuts. A plant that can meet the variations in electricity demand is therefore a priority for European Industry.

Such a plant will also have to meet the greenhouse gas emission constraints. Current targets are set by the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC). In line with this the EU is committed to reduce emissions by 8% by 2012. Since the power generation sector is one of the main $CO_2$ emitters in the EU, the consensus is that future plant concepts will have to be of a type that produces low volumes of emissions.

Improvements to the efficiency of fossil fuel plants, from raising steam temperatures and pressures will offer some limited gains in emissions. But to make a significant reduction in greenhouse gas emissions, the $CO_2$ that is produced when generating electricity needs to be captured and then stored. Generating plants of this type will be very advanced indeed. For many designs it would be unrealistic for them to have to vary electricity output to meet daily and hourly changes of electricity demand. In particular, such plants are likely to suffer extremely badly if they have to be shut down and started up, at short notice, since the temperature variations induced in superheaters, reheaters, and turbines will induce thermal fatigue cracking [5]. These thermal fatigue problems are exacerbated as steam and gas turbine temperatures increase, but the ability to operate at high temperatures is even more essential in carbon capture generating plant. This helps offset the reduction in efficiency caused by power losses, which result from the need to capture the $CO_2$, and then compress it for pipeline transport to storage sites.

In contrast to plants that produce electricity only, HYPOGEN plants have the capability of meeting these twin demands of reducing greenhouse gas emissions and being able to vary electricity output with no operational or economic penalty .In a HYPOGEN plant the production of hydrogen simplifies the capture of carbon dioxide. The hydrogen which is produced in this way can be burnt as fuel in a combined cycle power plant on the same site, or sent by pipeline to consumers. In this way HYPOGEN can improve the environmental performance of the power generation sector, thereby helping the EU to meet its greenhouse gas targets. This is of vital importance, since, in the near to medium term, natural gas and coal based generating plant will continue to be one of the main sources of electricity, if only because there is no viable means of storing this form of energy.

HYPOGEN will also accelerate the development of the hydrogen economy in Europe as it is a large and reliable source of hydrogen.

Furthermore the main feature of HYPOGEN that it has two energy outputs, one being electricity, the other hydrogen, can be used to overcome the problems caused by having to vary the electrical output of the plant. Rather than the plant operating with a fixed ratio of electricity to hydrogen, the IE proposal is that this ratio should be variable, with the plant being able to change its output from 100% hydrogen to 100% electricity. Figure 2 shows schematically how such a plant might operate. As electrical demand falls, the hydrogen output increases. To summarise, the HYPOGEN plant would operate at a constant fuel input, producing hydrogen all the time as the primary product. The hydrogen would be used to produce electricity when the demand for power was high. At other times, when the demand for electricity was low, the hydrogen would be sent out from the plant, to consumers, via a hydrogen pipeline network. The ability to quickly change the type of energy output, from hydrogen to electricity, would be a major consideration in design of the plant.

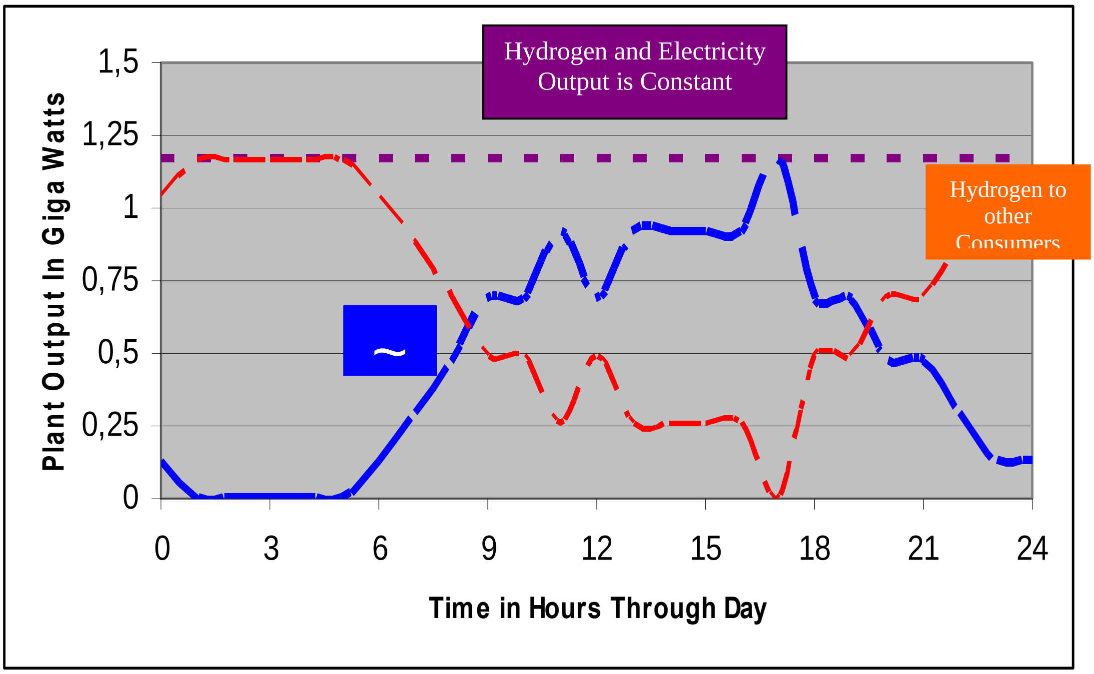


**Figure 2: Schematic showing a flexible HYPOGEN plant in which energy throughput is constant, but the amount of hydrogen produced is increased as electricity demand falls**

The report has been built on previous JRC-publications [6]. It also incorporates thinking behind reports and papers sponsored from other organisations, where in general the emphasis has been on, using **gasification** or **steam reforming** to produce **electricity only** from coal or natural gas, and where the process incorporates a step to capture the carbon dioxide. [7,8,9,10,11,12]. This is in contrast to a HYPOGEN plant, which as emphasised above, is intended to produce **both electricity and hydrogen** from a fossil fuel.

All fossil fuels can be used to produce hydrogen, by a gasification process, whereby the carbon in a fuel reacts with oxygen and/or steam to form hydrogen and carbon dioxide. In practice, the conversion process cannot be completed in one step. It is necessary to go through a number of stages to increase the proportion of hydrogen in the gas, to remove sulphur compounds, produced from impurities in the fuel, and to separate off carbon dioxide. There is also a variant of the gasification process, known as steam reforming, in which natural gas is reacted with steam or with steam and oxygen, using a catalyst, to produce hydrogen. The chemical reactions are much the same. But unlike current "gasification processes", which use coal or heavy oil, the use of natural gas greatly simplifies the plant configuration and costs.

With coal based processes, HYPOGEN is based on the **I**ntegrated **G**asification **C**ombined **C**ycle (**IGCC**) form of generating plant. An advantage of this form of power generation is the very low emissions of sulphur compounds and particulates. In the IGCC, coal or heavy oil is gasified to produce a fuel gas consisting of hydrogen and carbon monoxide, plus inerts (non combustible gases) such as carbon dioxide and nitrogen. The fuel gas is burnt in a combined cycle gas turbine system, where the electricity is actually generated.

It needs to be emphasised, however, that the limited number of IGCCs that are currently in service do not aim to produce hydrogen, per se. Nor is one of the aims, unlike the HYPOGEN concept, to capture the $CO_2$ for storage. However in a HYPOGEN plant, just as with standard IGCCs, the hydrogen must be stripped of sulphur compounds (which originate from impurities in the fuel). The level of purity of hydrogen, in terms of sulphur compounds, carbon dioxide and other gases, will have a significant affect on plant efficiency and capital cost. This therefore is an important design consideration and will be discussed in this report.

Looking to the future there will be two main uses for the hydrogen that is produced. It can be distributed around the energy economy using high pressure pipelines, with some of it being used in either stationary or automotive fuel cells. Much of this hydrogen will also be used as a straight substitute for natural gas for cooking, providing hot water for washing, and for the heating of buildings. In addition, as indicated earlier, the hydrogen will be used in the HYPOGEN plant itself to fuel a gas turbine based combined cycle to produce electricity. Each of these uses will require different levels of purity, and could therefore affect plant configurations quite significantly.

Although steam reforming of natural gas is covered in this report, as a means of producing hydrogen, the main emphasis is on processes that are based on the gasification of coal. Figure 3 shows that a HYPOGEN facility will consist of a set of major units: (i) a unit where the feedstock is converted into a raw gas, whose main constituents are hydrogen and carbon monoxide, (ii) "shift reactors" for reacting carbon monoxide in the raw gas with steam to form hydrogen, (iii) an acid gas removal system for eliminating hydrogen sulphide and hydrogen chloride (iv) a unit for capturing carbon dioxide, and (v) gas or steam turbines for power production. In a plant all of these separate units would need to be optimised to ensure that, within the limits of current technology, the plant would produce hydrogen and electricity at good efficiency and low cost.

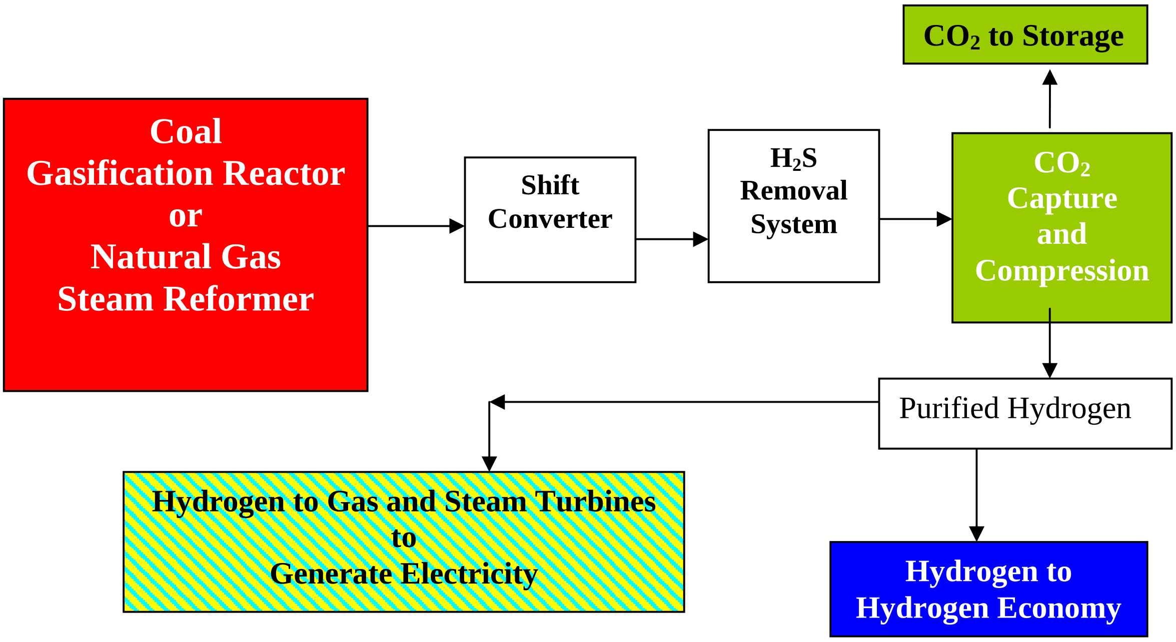


**Figure 3: Schematic showing how steam reformer or gasifier can produce hydrogen and capture $CO_2$ with hydrogen either going to hydrogen economy or being used as fuel to generate electricity**

Our previously published review on the co-production of hydrogen and electricity from fossil fuels made no recommendations on what was the most appropriate fossil fuel [1]. But in examining the advantages and disadvantages of each, the report did point out that the characteristics of the fuel determine the type of plant that would need to be used. It was also concluded that there was no off-the-shelf design that could be used for the efficient co-production of hydrogen and electricity. Indeed, to take the HYPOGEN concept forward, there is real need to construct a large test facility, basing this as far as possible on existing technology. Only in this way would it become clear what are the critical issues in terms of design, construction, and operation.

Here it should be noted that it would be possible to run a more conventional generating plant, suitably modified for capturing $CO_2$ in which the basic output was electricity. This could also be made to generate hydrogen, using electrolysis of water, at times when the demand for electricity had fallen away. The drawback of this approach is that the cost of the hydrogen, in energy terms, because of the conversion losses, will be greater than of the electricity. In addition, as well as the cost of the electrolysers, there will be significant further costs, in both capital and running costs in having to compress the hydrogen up to pipeline pressures as there are no commercial processes for producing electrolytic hydrogen at high pressure.

The main aim of this report is therefore to take these arguments further. Although accepting that a number of gasification type processes have been used to produce electricity and, in the case of steam reforming processes, hydrogen, it re-affirms that none of these are really suitable for a HYPOGEN plant. The report highlights the main shortcomings of current conversion processes and indicates what features need to be examined in more detail. Many of the suggested changes can only be fully evaluated using process flow modelling. The input data for such activities depends very much on the type of fuel and the exact nature of the process. Accordingly, this report should be used as a guide to help formulate some of the issues that should be considered in designing the HYPOGEN facility.

To clarify possible design problems the report takes a step-by-step approach to the issues, and in so doing also gives a brief account of some of the factors which govern the design of a conventional natural gas fired combined cycle plant. This has been done since an understanding of the design background to the steam generators (i.e. boilers and superheaters) in conventional combined cycle plant is important when considering how such a facility can be incorporated into a HYPOGEN plant.

HYPOGEN would be the focus of a European based programme to build such a plant as a large-scale demonstrator. Preliminary design work is due to start in 2006. HYPOGEN, if successful, should lead to the construction of a number of such plants, both in Europe and in other continents. It will face competition from similar Japanese and American concepts, so it is important to establish a well thought out and feasible plant specification.

Appendix 1 indicates some hydrogen and electrical outputs and efficiencies for medium sized HYPOGEN plants based on steam reforming or coal gasification processes.

## 2. Key Considerations in the Design of the HYPOGEN Facility

### 2.1 Hydrogen Production: Cost and Purity Aspects

In a fully developed hydrogen economy, hydrogen and electricity will be energy carriers in competition, just as natural gas and electricity are today. Electricity has great advantages over all other forms of energy, including hydrogen, in that its conversion to power or heat is virtually 100% efficient.

The main shortcomings of electricity are that it cannot easily be stored and its generation, using steam, CCGT, and IGCC plants is relatively inefficient. If electricity is produced from coal, power plant efficiencies will be in the 40-45% range on a HHV (Higher Heating Value) basis. As noted above, extra losses, due to carbon capture, would bring efficiencies to well below 40%. In contrast, it should be possible to produce hydrogen from coal at efficiencies around 55-60%, whilst simultaneously capturing the carbon dioxide. It follows that a coal based facility would yield more energy when producing hydrogen than when generating electricity. Other things being equal, hydrogen costs should be lower than that of electricity, in energy terms. Working against this is the fact that electricity can be sold at a higher price than hydrogen, as electricity is for most purposes a more convenient and adaptable form of energy. Nevertheless hydrogen from this type of IGCC-Hypogen system should be much less costly than that coming from a carbon capture pulverised fuel steam plant, where off peak electricity could be used to produce hydrogen by electrolysis of water. Because of the conversion losses in electrolysis, an IGCC-Hypogen plant could produce up to twice as much hydrogen, from the same coal input, as a pulverised fuel plant

It is generally recognised that the production cost of electricity in IGCC plants is strongly determined by the high capital and maintenance costs of the plant. This is a result of the complexity of the plant and difficulties in handling a solid feedstock such as coal. An IGCC, modified to produce hydrogen, would face a similar challenge, as indicated by a recent study which suggests that capital costs would account for around two thirds of cost of the hydrogen [13]. In contrast the hydrogen costs from steam reforming plants tend to be dominated by the cost of fuel. Figure 4, based on a study from CB&I Howe-Baker Inc shows that the combination of capital, fixed operating, and maintenance costs are equivalent to about 2.5 Euros /MWh for hydrogen manufacture.

It follows that the reduction of capital costs of a coal based IGCC plant has to be a critical factor in its design. The incentives to reduce capital costs of steam reforming plants are somewhat lower. In this case the cost of the fuel does suggest that high conversion efficiencies to hydrogen and electricity are probably more dominant. However as will be shown the capital costs of a steam reforming plant, where a high level of capture of carbon dioxide is needed, will be higher than that of the typical steam reformer of today. Here too there is some need to focus on capital costs.

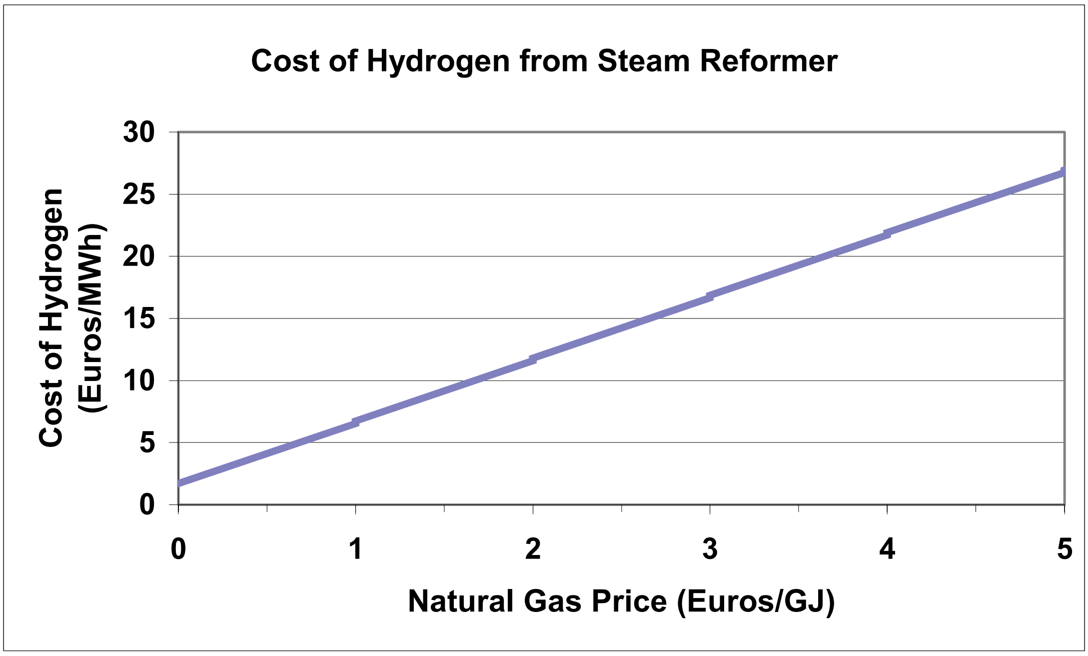


Figure 4: Cost of hydrogen from steam reforming processes

The reduction of capital costs and maximisation of the output of hydrogen will in part be determined by considerations of hydrogen purity. High purity will tend to push up costs and reduce output. Table 1, based on ISO 14687, summarises current specifications for hydrogen [14]. Discounting the requirements for space vehicles and aerospace, where high purity is needed, because of the need to liquefy the hydrogen, the constraints on gas purity, associated with Grade A and B compositions may be unnecessarily restrictive, and if rigorously applied will increase capital expenditures and lower the efficiency of hydrogen production.

Grade A hydrogen purity, for example, requires hydrocarbons to be kept below 100 ppm and carbon monoxide below 1 ppm. For many potential users in the Grade A set, such as those operating IC engines or gas appliances, much higher levels of these impurities would be acceptable. Similar criticisms can be made of the Grade B specification. This is intended for industrial fuel users, where the purity requirement seems to be much more severe than that associated with the main industrial gaseous fuel of the present time, namely natural gas. Only those who would be operating PEM type fuel cells would need very high level of purity levels [15, 16]. But for these applications, it will also be necessary to eliminate sulphur containing odorising compounds from the hydrogen, since these too are highly poisonous to fuel cell catalysts. In practice both sulphur compounds (from whose smell, gas leakages can be recognised) and carbon monoxide could be removed at the point of use by the PEM fuel cell operator.

**Table 1: Purity Levels for Hydrogen from ISO 14687**

| Component | Grade A IC Engines/ Automotive Fuel Cells/ Gas Appliances | Grade B Industrial Fuel for Power Generation | Grade C etc Aircraft and Space Vehicle Uses |
|---|---|---|---|
| **Hydrogen** | 98% | 99.9% | 99.995% |
| **Total Gaseous Impurities** | Water Vapour, $O_2$ ,$N_2$, Ar<br>Total 1.9% max | <50ppm | <50ppm |
| **Water Vapour** | See above | Not Condensed | Water Vapour, $N_2$, Hydrocarbon<br>Total 9 ppm Max |
| **Oxygen** | See above | 100 ppm | $O_2$+Ar<br><1ppm |
| **Argon** | See above | ------ | See Oxygen above |
| **Nitrogen** | See above | <400ppm | See Water Vapour above |
| **Hydrocarbons** | <100 ppm | Not condensed | See Water Vapour above |
| **Helium** | ------ | ------ | <39 ppm |
| **Carbon Dioxide** | ------ | ------ | $CO_2$+CO<br><1ppm |
| **Carbon Monoxide** | <1 ppm | ------ | See $CO_2$ |
| **Mercury** | ------ | <0.004ppm | ------ |
| **Sulphur** | <2.0 ppm | <10 ppm | ------ |

If there is a need to purify to the very high levels as required by current Grade A and B specifications, the main technique currently available is that of Pressure Swing Adsorption, commonly known by its acronym PSA. Here the gas is passed over various adsorbents such as activated carbon or zeolites, which remove contaminants such as carbon monoxide and hydrocarbons. Although extremely effective, this does result in a significant loss of hydrogen, as periodically the adsorbents need to be regenerated as they become saturated with the contaminants. The hydrogen loss occurs through its use as a “sweep gas”, to carry away the contaminants, amounting to about 8-20% of the total hydrogen throughput [17].

Major PSA providers state that the purity of the hydrogen gas, which is produced, does not have a significant effect on hydrogen losses [18]. However, not all of this hydrogen is totally wasted. The tail gas from the PSA can be used, in a steam reformer, for heating the furnace, replacing some of the natural gas that would otherwise have to be used. In an IGCC plant modified to produce hydrogen, the tail gas could be used in a gas turbine, or it could be used to help raise steam in the heat recovery section of the plant, which would be subsequently used in a steam turbine. The power from the gas or steam turbines could be used to provide electricity for the gasification plant ancillaries and for $CO_2$ compression.

These arguments are supported in a paper from Princeton University, which indicates that opting for a “less pure” fuel grade hydrogen, containing 3.3% $CO_2$, 1.2% Ar, 1.0% $N_2$ and 0.9% CO, will reduce operating costs by 25% [19]. This reduced operating cost is achieved by elimination of the PSA unit, which when purifying the hydrogen to very high levels, produces a “tail gas”, containing about 10% of the hydrogen throughput. The only practical use for the tail gas is for power generation, resulting in the plant having to export a surplus of electricity at all times, Eliminating the PSA therefore converts the IGCC from one that has to export 31 MW of electricity, to one which needs to import 49MW. The loss in sales of electricity is more than made up for the increased output of hydrogen from the plant.

## 2.2 Electricity Production Using Hydrogen

Electricity will be generated in the HYPOGEN facility by burning purified hydrogen, from the gasifier, in a gas turbine, which will be part of a CCGT (Combined Cycle Gas Turbine. The combustion section of gas turbine will require a certain amount of development, since compared to natural gas, hydrogen has a low density, a lower calorific value, and higher flame speed. Ongoing R&D work shows that the necessary modifications can be made easily and at a minimum cost [20].

### 2.2.1 Impact of the Calorific Value of Hydrogen

A major drawback, in the use of hydrogen as fuel is the inability to recover all of the heat energy which is produced when hydrogen is burnt. This results from the fact that when hydrogen burns water vapour is produced. To utilise all the heat that is generated would require condensing the water vapour, thereby making use of its latent heat. This is not possible in practice, and results in approximately 18 % of the potential heating energy in the hydrogen being lost [21]. This accounts for the extreme difference between the higher and lower calorific values of hydrogen.

No such problem occurs when carbon monoxide is burnt. There is only one calorific value for this gas, as water vapour is not formed during combustion. The calorific value of carbon monoxide is almost the same as that of the higher calorific value of hydrogen, the figures being respectively, 283 and 284 MJ per mole [21]. However since the lower calorific value of hydrogen is only 240 MJ per mole, it can be seen that a CCGT plant, operating on hydrogen, would deliver significantly less power than one utilising carbon monoxide as a fuel.

This has serious implications for an IGCC (Integrated Gasification Combined Cycle) system in which the gas turbine section is modified to run on hydrogen rather than on syngas. In a standard entrained bed gasifier, roughly two thirds of the heating value of that gas will come from the combustion of carbon monoxide, as syngas typically contains 60-70% CO. Hydrogen in these conditions will only provide about 30-40% of the heating value of the syngas, although in other types of gasifier the proportions of hydrogen can be higher or lower [20, 22]. For this reason an entrained bed IGCC plant that combusts syngas will tend to run at a higher efficiency than that of a similar plant running on hydrogen, even discounting the energy needed to capture the $CO_2$.

This loss of energy in converting fossil fuels to hydrogen, also largely accounts for the relatively low fuel-to-hydrogen efficiencies of such plants. If the hydrogen is subsequently burnt in a condensing boiler, or used in a low temperature PEM fuel cell much of this loss can be recovered, as the flue gas temperature is then low enough for water to condense.

### 2.2.2 Mass Flow Through Turbine

In a conventional IGCC, the gas turbine also tends to produce more power when running on syngas than when it is burning pure hydrogen. The combustion of syngas produces carbon dioxide, as well as water vapour. As carbon dioxide has a relatively high density, compared to other gases, the mass flow through the turbine will be higher, for a given volumetric gas flow. Hence because the driving force to turn the turbine is greater, more power is produced. Additional mass flow also results from the presence of "uncaptured $CO_2$", nitrogen and argon, which are present as non combustible gases in the syngas. This additional mass of gases enables the turbine to generate more electricity.

To help overcome this particular shortcoming of a hydrogen fuelled gas turbine, in a HYPOGEN plant, it may be acceptable to use relatively impure hydrogen to increase the mass flow, thereby increasing the turbine power and electricity output. All of the nitrogen and argon and a certain amount of carbon dioxide would be left in the fuel gas to the gas turbine. Clearly when producing hydrogen only for export to a pipeline, a higher level of hydrogen purity would be required, although purity levels should be determined by what is acceptable to the majority of customers, rather a composition based on some arbitrary specification.

The main consideration is how far HYPOGEN should go in meeting any recommendations for carbon capture. There does not appear to be a definite standard for the level of $CO_2$ that should be captured, although capture rates of about 90% have been suggested [23]. An early IEA report indicated a minimum level of 80%, but in other projected schemes, one based on steam reforming of natural gas, the other on coal, the respective figures were 85% and 97% [24]. Newer reports give capture rates of about 85% [25]. Much seems to devolve upon the type of generating system, and the method of capturing the $CO_2$. However, the capture rate will be indicated by the cost of carbon capture and storage compared with the price of $CO_2$ in the frame of the European carbon trading system. Anticipating carbon dioxide prices of the order of €20/tonne in the medium term, the capture rate should correspond to costs within this price range. In a HYPOGEN facility, the hydrogen purity specifications entail the removal of all $CO_2$. If it were acceptable to release some $CO_2$ to the atmosphere when producing electricity, there would be benefits in plant efficiency and output. In a steam reforming plant, rather than leave some $CO_2$ in the hydrogen, it may be possible to leave much of the methane that was not reformed (<5%) in the hydrogen. Similarly, if the syngas was produced from coal, at least some of the carbon monoxide could be left in the hydrogen that was to be burnt. These are issues which need to be explored in any process flow modelling to optimise plant out put and efficiencies.

### 2.3 Plant Flexibility, Marketing Implications and Self Sustaining Capability

HYPOGEN type plants, by definition, are an unusual type of energy conversion systems in producing two energy carriers, namely hydrogen and electricity. It is a point to be debated how much of the costs of the plant should be borne by each of the two fuels. In purely energy terms as there are significantly lower losses when producing hydrogen than electricity the cost per unit of energy should be lower for hydrogen.

However in practice this issue of the internal budgeting of the costs will be somewhat academic, as the key factor will be what the market will accept in terms of the prices that must be paid for hydrogen or electricity. On balance, because electricity can be converted into other forms of power or energy very easily, it should be possible to charge customers more for this form of energy. Indeed at times of peak electrical demand, the gas turbine may be able take extra hydrogen from the $H_2$ pipeline transmission system to produce extra power and extra revenue.

Furthermore if a HYPOGEN plant is flexible, in being able to vary the ratio of electricity to hydrogen as the market demanded, it should be possible to load up capital costs onto the sales of electricity, thereby reducing the selling price for hydrogen. The approach would be to maximise electricity production during the day. At night, when demand falls away, the plant would switch over to hydrogen production, with minimal or even zero sales of electric power at this time [26]. The cost of “Night Time Hydrogen”, from such a plant, could then be basically determined by the fuel costs, and little else. Although it may not be possible to load all the capital costs onto electricity in this way, this does give an incentive to aim for a fully flexible plant, that is, one that can switch from 100% hydrogen to 100% electricity, whilst ensuring that the plant runs at maximum throughput all the time. This clearly is an important design requirement, and a major issue would be the capability to vary the ratio over a relatively short time period, without causing serious harm to the equipment.

A flexible ratio plant is likely to have slightly higher capital costs, and lower conversion efficiencies, than those of a plant where the ratio of hydrogen to electricity is fixed, or only allowed to vary over a small range. Fixed ratio plants, by having a high degree of plant integration, are optimised to have the highest possible efficiency and lowest capital costs. In theory this will lead to the lowest possible electricity and hydrogen prices. This approach neglects the fact that with a fixed ratio plant, when the electrical demand falls, the only option would be to lower both hydrogen and electricity outputs. In the extreme, if there was no requirement for electricity, the plant would have to be taken off-line, as with a conventional power plant. This would be difficult to arrange with steam reforming or coal IGCC plants because of the drop in catalyst temperatures, the risk of damaging catalyst integrity and performance, and the risk of explosion during restarts. It also follows that both electricity and hydrogen costs would be badly affected because capital costs would need to be spread over reduced plant output.

A prime consideration in designing a variable ratio plant is the choice of steam reformer or gasifier, as this greatly influences the quantity and grade of waste heat that is produced. The waste heat is contained in the hot exit gases from the steam reformer or gasifier, and the lower the efficiency of conversion of fossil fuel to carbon monoxide and hydrogen, the greater the quantity of waste heat. Typically this is of the order of 20-30% of the energy input in the fossil fuel. The waste heat is used to produce steam which can be employed in the steam reforming or gasification process reactions, and waste heat in some form is always used to regenerate the solutions needed for removal of sulphur compounds and $CO_2$. Surplus steam could also, in principle be used to produce electricity. For efficient power production, however, this requires the steam to be high grade, that is, to be available at high temperature and pressure. Acceptable values would be temperatures of over 400°C and pressures in excess of 40 bar, which it can be shown gives the capability of converting about 30% of the energy in the steam into electric power. More steam can also be produced from the waste heat generated in the shift conversion reactions, but this is normally of the low grade type, which is not of great use in the production of power.

Ideally, when the HYPOGEN plant is producing 100% hydrogen, the surplus steam should be just sufficient to produce enough electricity to drive the pumps and compressors that are needed to keep the plant operating. That is there would be no export of electric power, since this would defeat the object of the flexible concept, which is only to export electricity when there is a good price. Setting the plant parameters to achieve this condition should be a priority in any process flow modelling activities, making the plant self-sufficient in terms of electric power needs.

It follows from this that the combined cycle section of a flexible HYPOGEN facility, intended to produce electricity for sale, would need to be started up when the price of power was high and shut down when the price fell. This happens to much natural gas fired combined cycle plant at the present time, as plant has to two-shift owing to the day-to-night variation. Because of the temperature changes in the heat recovery section of the conventional CCGTs serious problems occur with thermal fatigue. In the proposed HYPOGEN concept these problems will be minimised by using a small amount of steam from the boilers and superheaters in the gasifier heat train to keep the heat exchangers in the combined cycle plant hot, even when not operating. In addition, this design feature would allow power production to be brought up to full load very quickly because the CCGT heat exchangers are kept at temperature.

## 3. Steam Reforming Based HYPOGEN Processes

Where natural gas is available, steam reforming is the favoured means of producing hydrogen. The hydrogen is subsequently used for hydrocracking in refineries or may be used in combination with nitrogen to produce ammonia, or in the production of methanol and urea. These applications greatly influence the treatment of the syngas from the reforming process as each requires hydrogen of a different degree of purity. For a HYPOGEN type plant, a major issue could be the need to remove nitrogen, which would be present in varying amounts, depending on the source of the natural gas feedstock. In this respect L-type natural gas, typically from the Netherlands, has a nitrogen content of around 12%, which would probably not be ideal for a flexible HYPOGEN plant, as its removal would entail significant losses of hydrogen in the purification stage [27]. H-type natural gas from the North Sea, with 2.6% nitrogen, and gas from Russia, at 1.3%, would be much more suitable for the production of hydrogen for the energy sector.

Various types of steam reforming process are described below. To meet the flexible ratio criterion, they should be able to meet the self-sufficiency requirement for steam and electricity when the plant is producing hydrogen only. Modern steam reforming plants tend to rely on PSA for removing $CO_2$ and other gases. Such plants produce a surplus of steam, since there is no real use for much of the steam produced in cooling the hot reformed gas and syngas down to room temperature [13]. In a HYPOGEN plant most of the $CO_2$ is likely to be removed using alkaline solutions, using processes which require steam to regenerate the solutions. Hence, it possible that a HYPOGEN facility might be short of steam. This presents no real problem as any shortfall in steam production could easily be rectified by the installation of a small boiler, fired with hydrogen.

A shortcoming of conventional steam reforming is that the exit gas from the steam reforming furnace contains percentage levels of unconverted methane. Because of this reason hydrogen production also suffers. In modern processes, the amount of methane can be reduced by passing the reformed gas to a secondary reactor where most of the remaining methane is eliminated by a partial oxidation process, using either oxygen or air. Oxygen would be needed when the final product from the plant is to be hydrogen. (When steam reforming is used to produce ammonia, air is used for the partial oxidation reaction). Since this reaction is exothermic, partial oxidation reactors do not require external heating, and the reactor consists of an internally insulated pressure vessel containing the catalyst. The main reaction is shown below:

$$\mathbf{CH_4 + O_2 \rightarrow 2H_2 + 2CO}$$

In a HYPOGEN plant the oxygen would be provided from a cryogenic ASU (Air Separation Unit. The power for the ASU could come from a separate gas turbine. Here it should be noted, that the amount of oxygen, and therefore the ASU power requirement, is much smaller on a steam reforming plant than an IGCC system, since the autothermal reformer is only responsible for converting a small fraction of the fuel into the plant into hydrogen. As described earlier, when the plant has to switch to electricity production, the hydrogen would be diverted into a conventional CCGT system, whose HRSG could be essentially independent of the steam system in the reforming plant.

## 3.1 Conventional Steam Reforming

Catalytic steam reforming of natural gas is the most widely used method of producing hydrogen. The steam reforming reactions are endothermic, that is heat must be supplied to the reactants, on a continuous basis, to sustain the reactions. Accordingly the reactants, consisting of superheated steam and natural gas pass into a set of tubes filled with nickel-rich catalyst pellets, which are heated inside of a box-like furnace. This furnace is termed a primary reformer, the fuel for which consists of a mixture of natural gas and tail gas from the PSA [28, 29, 30].

The steam reforming reaction reacts methane with a large excess of steam to give a “reformate”. This consists of hydrogen, carbon monoxide and some carbon dioxide, plus some unreacted methane and steam.

Before entering the reformer tubes, sulphur compounds are removed from the natural gas. The first stage of the treatment is to convert organic sulphur compounds to $H_2S$ by passing a mixture of the natural gas, plus some hydrogen, though a pressure vessel containing a cobalt-molybdenum oxide based catalyst. The gas mixture is then passed through a second pressure vessel, containing zinc oxide, where the $H_2S$ is absorbed. This is necessary to preserve the reactivity of the catalyst pellets. After desulphurisation, the natural gas is mixed with the superheated steam just before it enters the set of tubes in the reforming furnace. About 10% of the hydrogen that the plant produces has to be recycled because of the need to remove sulphur. Figure 5 is a schematic of the process in which the aim has been to maximise high purity hydrogen production.

The mixture of gases emerging from the reformer tubes contains hydrogen, carbon monoxide, some carbon dioxide, plus a substantial amount of steam and some methane. Exit temperatures are around 900°C and pressures at 25 bar. The gas composition is determined by the gas temperature, pressure, and proportion of steam in the mixture, but the aim is to maximise the hydrogen content and minimise the amount of methane that remains in the gas after it leaves the reactor. Increasing the temperature of the reactants will reduce the methane content, but to get the methane down to very low levels will require the reformer to work at impractically high temperatures. Further processing of gases from the primary reformer is needed, therefore, to eliminate the methane.

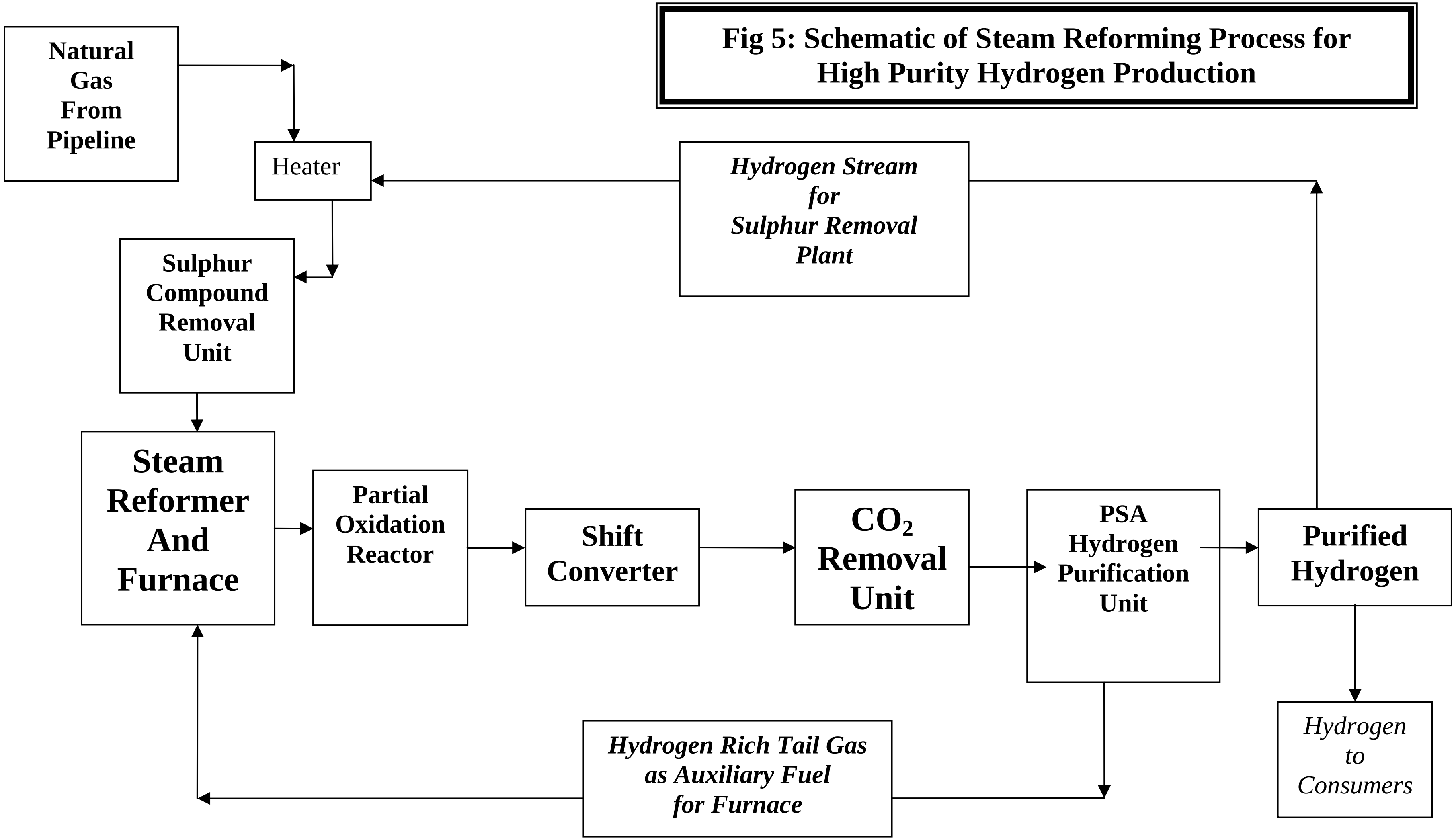
Accordingly the products from the reformer can be passed to a partial oxidation reactor, which will cut the methane concentration to very low levels, as described in Section 3.2. In older processes the reformate is cooled to about 400°C and used to raise steam by passing it through a reformed gas boiler. The mixture of steam, hydrogen, carbon monoxide and the methane, in the cooled reformed gas, is passed to a shift converter where the carbon monoxide and steam react to form carbon dioxide and hydrogen.

After the shift reaction most of the $CO_2$ is captured using liquid absorbents, which is be based on amines or potassium carbonate. In newer plants the removal of final traces of $CO_2$ is carried out using PSA, which also facilitates the removal of contaminating gases such as carbon monoxide, nitrogen and methane. The tail gas from the PSA contains a substantial amount of hydrogen, which is mixed with natural gas and used for firing the reforming furnace, as indicated above.

A process route of this type would not be suitable for a HYPOGEN plant, in which carbon capture is a critical feature, as a conventional steam reformer releases $CO_2$ because of the use of natural gas to heat the reformer. Additional $CO_2$ is likely to be released to the atmosphere when the tail gas is burnt in the furnace, as the tail gas could contain a substantial proportion of the $CO_2$ that was formed in producing the hydrogen.

There are drawbacks to using a proportion of the hydrogen as a fuel gas in the reforming furnace. The size of the reforming plant, as a whole, would need to increase by about 25%, as more natural gas would have to be reformed and the heat balances in the system would change. The design of the reforming furnace would need special consideration, as the emissivity and combustion characteristics of hydrogen are quite different to that of natural gas, as there is no $CO_2$ or small amounts of soot to enhance the radiation characteristics of the

Fig 5: Schematic of Steam Reforming Process for High Purity Hydrogen Production



flames [31, 32]. Flame temperatures would tend to be higher [33]. It would probably mean that the temperature of the combustion products exiting from the reformer box would be higher than that on a conventional plant, and this would have implications for the heat recovery units in the flue gas duct. There would almost certainly need to be a combustion air preheater to recover the heat in the flue gases, which is a piece of equipment not always fitted to conventional steam reformers.

## 3.2 Autothermal Reforming

The strength of the reformer tubes, which is heavily dependent on their operating temperature, limits the outlet pressure of a simple steam reforming plant. This may cause difficulties if the hydrogen has to be transmitted over long distances. The restrictions on pressure and temperature also govern the amount of methane that is converted to hydrogen, so that a significant amount of methane is present in the reformed gas. Only by operating at a very high temperature is possible to get very low concentrations of methane. To improve the conversion rate the syngas can be passed to a secondary reformer, in which most of remaining methane reacts with oxygen to produce hydrogen and carbon monoxide [28, 29, 30]. This has no significant temperature or pressure restrictions. In addition, as it is possible to operate the steam reformer, or primary reformer, at lower temperatures, it is possible, in principle, to run the process at somewhat higher pressures.

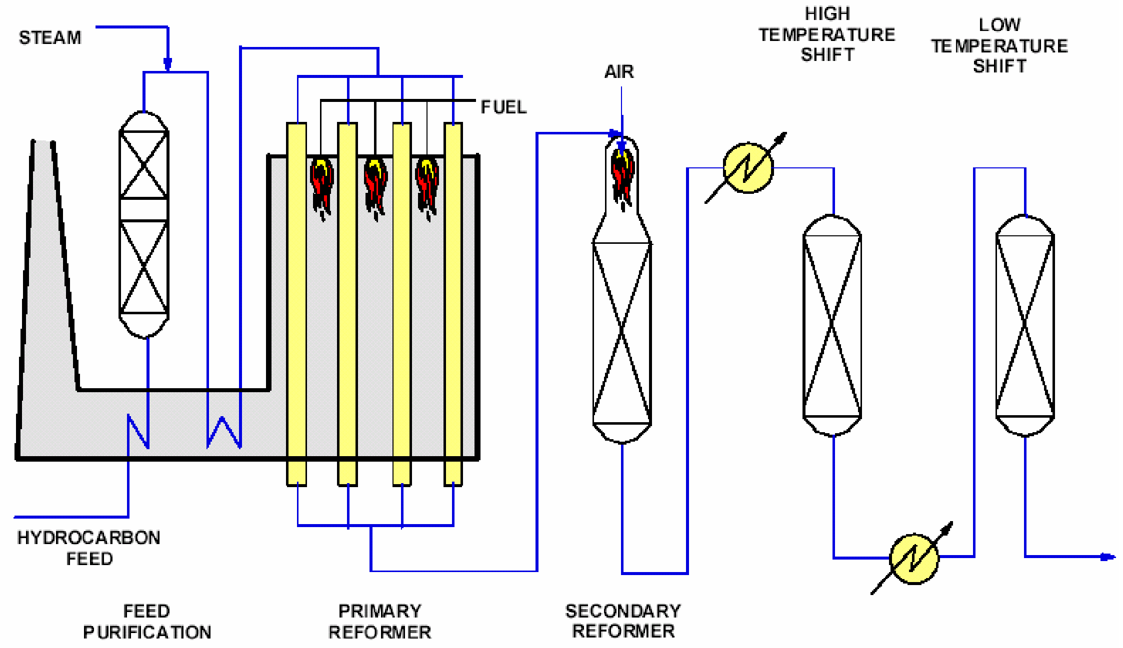


**Figure 6: Schematic of typical steam reforming process for hydrogen production in an ammonia plant. In a HYPOGEN plant oxygen, rather than air, would be fed to the secondary reformer [30].**

At the entrance of the secondary reformer, the gas from the primary reformer is partially combusted with either air or oxygen. The energy released provides the heat for the steam-methane reforming reaction, which takes place in a bed of catalyst, further down in the reactor. The process is termed autothermal reforming, as there is no external heating, since the reaction is highly exothermic. For the production of hydrogen, it would be necessary to use pure oxygen, so as to minimise the nitrogen content of the gas. Methane levels are reduced to less than 1%. Figure 6 shows a schematic of a typical plant, which in this case, as the final product from the site is ammonia; air is being used as the oxidant rather than pure oxygen.

The downstream processes are similar to those of conventional steam reforming, in that the carbon monoxide is converted into hydrogen in a shift reactor, with the carbon dioxide being removed by an absorption process.

Although in principle it should be possible to carry out all of the reforming in a secondary reactor, this is not done in practice. The natural gas would need to be heated before it entered the secondary reactor, and there could be a risk of the reaction getting out of control, as the methane levels in natural gas are much higher than in the syngas from a primary reformer. The whole configuration of the plant would change. The oxygen plant would need to be far bigger, as would the shift converter. For this reason autothermal reactors are invariably coupled with an upstream steam reforming unit. This tends to impose a limit on plant pressures. To circumvent this, a number of new processes have been developed as described below.

### 3.3 New Reforming Processes

The main feature of these newer processes is that the tubes for the steam reformer are situated within a pressure vessel, which contains a hot gas at high pressure. This reduces the stress on the tubing and permits the outlet pressure of the process to be raised, in principle, to high levels. Such a process should enable hydrogen to be produced at even higher pressures than in autothermal processes.

For hydrogen production, processes of this type have attractive features. They eliminate the need for a reforming furnace, as all the heat for the reforming reaction comes from the secondary reformer [34, 35, 36, 37]. Beside the potential to run at a high pressure, the need to heat the steam reformer using some of hydrogen from the plant is eliminated. All the natural gas goes through the gas heated and secondary reformer, so the problem of $CO_2$ releases to the atmosphere, along with the flue gases, is circumvented.

In these new processes, the tail gases from a PSA would have to be used for power generation, as the use of them as a fuel feed to the reforming furnace has been eliminated. This might not be too much of an issue if there is a large demand for ancillary power on the plant, but we have no means of estimating this at this stage. If there is an excess of power, the concept could start to move away from the ideal of a fully flexible HYPOGEN plant, as there would always be a need to sell some electricity. It should also be noted that since more of the reforming process goes on in the secondary reactor, the concentration of carbon monoxide in the gas stream to the shift reactor will be greater than in conventional steam reformers. This would imply the need for a bigger shift reactor and perhaps an excess steam production, beyond what the chemical processing in the plant requires. The excess steam would also have to be used for power production and the combination of power from the tail gas stream and the steam from the shift converter boilers could result in the plant seriously moving away from the flexible HYPOGEN concept. This issue should be investigated using process flow analysis.

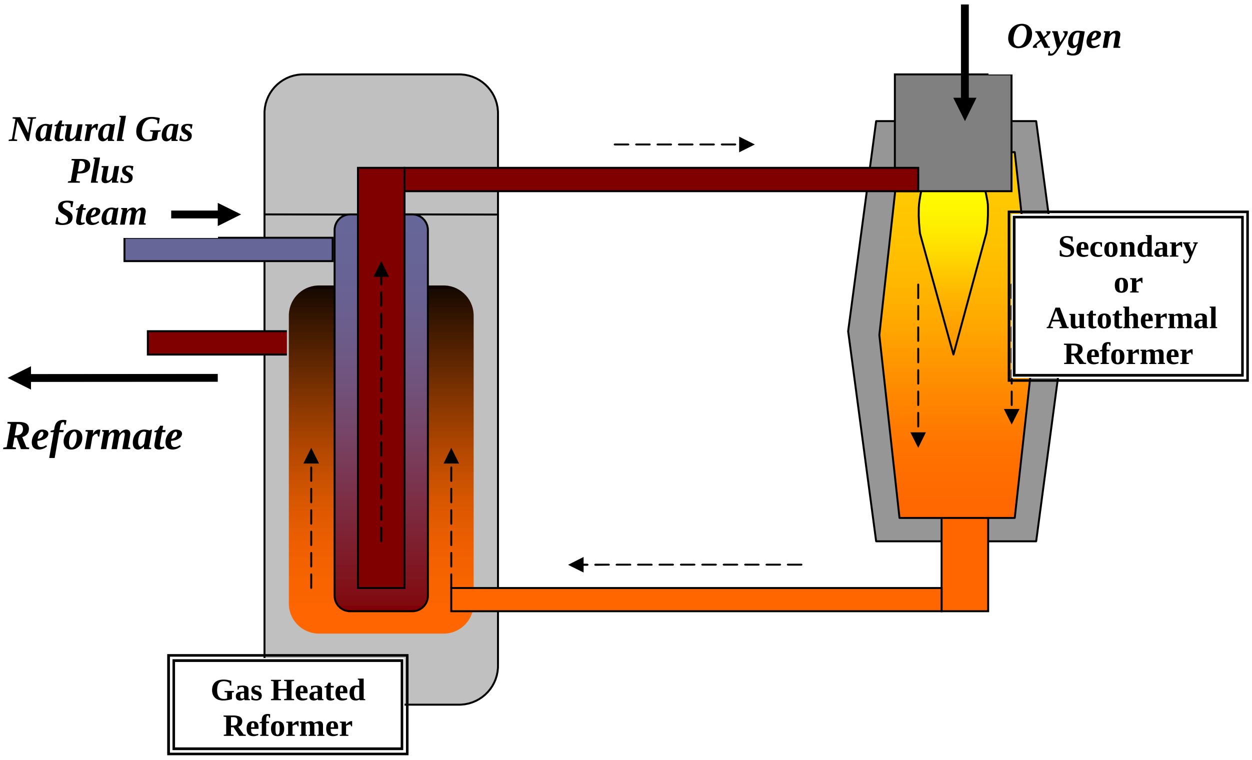


**Figure 7: Schematic of a newer reforming process in which reforming tubes are situated in a pressure vessel heated by hot gas from a secondary reformer**

### 3.4 Overall Potential for Steam Reforming

Although steam reforming has been used for the production of hydrogen for more than sixty years, and during the last decades some very interesting developments have taken place, there is not one system that could be used in an off-the-shelf manner as the core of a HYPOGEN facility. It follows that if natural gas is to be the fuel for a HYPOGEN plant, the merits of all the three routes described above needs to be assessed using process flow analysis.

A general shortcoming of even the newer processes is that they do not work at the kind of pressures required for very long distance transmission of hydrogen. However, this is less of a problem with steam reforming plants than with coal gasifiers, as the former can be located reasonably close to potential markets as the natural gas fuel can be piped long distances to the steam reforming plants. Conversely coal based gasification systems will be largely tied to coalfields or to seacoast or river locations which have appropriate facilities for importing coal. But given the expected steam production from a flexible HYPOGEN plant, a vital matter is whether steam reforming based process will always be generating more electricity than the plant itself consumes. This undoubtedly is a very real issue since the power demand from the ancillaries on reforming plant will be significantly less than that on an IGCC system.

## 4. Coal Gasification Based HYPOGEN Processes

### 4.1 IGCC Background

#### 4.1.1 Gasifiers for IGCC Plants

The IGCC (Integrated Gasification Combined Cycle), upon which any coal fuelled, hydrogen production system would be based, is a comparatively new method of utilising the chemical energy in coal to produce electricity. Modifications of some designs of IGCC represent the best possible method by which the chemical energy in coal can be transformed into hydrogen. It also provides a simple route by which the carbon in the coal can be captured for storage in an underground reservoir.

All types of gasifier can be used in IGCC systems, as the syngas that is produced in all of them can be burnt in a combined cycle type gas turbine. The main downstream processes remove dust, sulphur and chlorine compounds to prevent damage to the CCGT gas turbine. The commercially available gasifiers, intended to produce syngas, can be divided into three basic types; entrained bed, fluidised bed and fixed bed designs. A more detailed description of gasifiers will be given in a future report, but with entrained and some fixed bed types, the temperatures are high enough, at over 1300°C, to cause most, if not all of the coal to react with oxygen or air (sometimes with water or steam additions) to form syngas. The temperatures in such gasifiers are sufficiently high for the ash in the coal to melt so that it can be drained off.

With fluidised bed designs, temperatures have to be kept below 1000°C to prevent the ash starting to melt, otherwise the particles of ash would gradually agglomerate and stop the bed from being fluidised. Unfortunately, the temperatures over which fluidised beds need to operate are too low to gasify all the coal, and a considerable amount of char is left. This has to be periodically removed and burnt in separate furnace to raise steam, which would be used for electricity generation using steam turbines. Such a plant would always be producing a substantial amount of electricity from the steam plant. In practice this would probably lead to a fixed ratio plant as the proportion of energy produced as hydrogen would be relatively small. Hence it would not be economic to put in a gas turbine set to use the hydrogen to produce even more electricity.

To summarise, in processes where all of the coal is turned into a gas, providing the main constituents of this are hydrogen, carbon monoxide and methane, such a gas can be subsequently treated in later processing stages of the plant to produce hydrogen. Furthermore, all such gasifiers could be used in a coal based HYPOGEN plant of the flexible type.

### 4.1.2 IGCC for Power Generation Only

The IGCC, in its current state of development, is generally considered to be only just competitive in efficiency terms with the best conventional pulverised fuel (PF) steam plant [38, 39, 40]. Its main shortcomings, compared to steam plant, are higher capital costs and, probably, higher manning costs. The main benefit, at present, of electricity generation using the IGCC is environmental, as virtually all the sulphur and chlorine in the coal are eliminated in the clean up of the syngas. This clean-up step utilises the standard purification processes for eliminating $H_2S$ (hydrogen sulphide), COS (carbon oxysulphide) and HCl (hydrogen chloride). Coal-derived mercury can also be removed, if thought necessary.

There are also good reasons to expect the efficiency of IGCC plant to eventually exceed that of even the best steam plant by at least 1-2%. This comes from the continued advances with natural gas fired CCGT plants, whose technology is directly applicable to the IGCC. It is also anticipated that developments with heat exchanger materials and sulphur absorption catalysts will allow more efficient use of the waste heat from the gasifier heat recovery system. Table 2 indicates the likely progress for pulverised fuel steam plant and IGCC up to 2050 [40]. This comparison is without $CO_2$ capture. Table 3 shows estimate of efficiencies with $CO_2$ capture, which show, as might be expected, PF steam plant being penalised more than IGCC [40]. These results are based on the lower heating value of the fuels, in contrast to American practice, where the gross calorific value is used as a basis. US plants therefore tend be quoted as having lower efficiencies for similar plants than in Europe. But a more fundamental reason for the difference is that condenser pressures in USA power plants are higher than in Northern Europe (because of the higher cooling water temperatures), and because sulphur contents of USA coals are higher than in coals used in Europe. Both of these factors will reduce the amount of power from a tonne of coal in US power plants.

**Table 2: Projected PF Steam and IGCC Plant Efficiencies up to 2050 without $CO_2$ Capture [40].**

| **Year** | **1990** | **2000** | **2010** | **2020** | **2050** |
|---|---|---|---|---|---|
| **PF Steam Plant** | 42% | 44% | 48% | 50% | 51% |
| **IGCC** | 42% | 45% | 50% | 54% | 55% |

**Table 3: Projected PF Steam and IGCC Plant Efficiencies up to 2050 with $CO_2$ Capture [40]**

| **Year** | **2010** | **2020** | **2050** |
|---|---|---|---|
| **PF Steam Plant** | 39% | 41% | 42% |
| **IGCC** | 43% | 45% | 46% |

In an IGCC, the coal is first gasified to produce a syngas, which, after cooling to permit removal of sulphur and chlorine compounds, is burnt as fuel gas in a combined cycle gas turbine system (CCGT). As the acronym suggests, all of the heat recovery systems and fluid flows between the gasifier and its processing systems, and the CCGT are closely integrated. The combined cycle section of the IGCC consists of a number of separate units, namely a gas turbine that burns the fuel gas from the gasifier, an HRSG (Heat Recovery Steam Generator) boiler/superheater, which picks up the waste heat from the gas turbine exhaust to generate steam, and a steam turbine which utilises the steam from the HRSG. Electricity comes from both the gas turbine and the steam turbine.

The IGCC is therefore a hybrid which results from the combination of two main energy conversion processes, a gasifier and a combined cycle power generating plant. The actual form of the plant is governed by the characteristics of the gasification system, the gas turbines, and method of producing steam. The current forms of IGCC are intended to produce electricity at the lowest possible cost. The design of such plants can be changed without too much difficulty to capture carbon dioxide.

For a HYPOGEN type plant which is intended to produce both hydrogen and electricity, whilst capturing carbon dioxide, an IGCC with carbon capture appears to be the most viable option. But as stated earlier, such a plant should, ideally, have complete flexibility, being able to switch from 100% hydrogen to 100% electricity.

A plant of this type, intended to convert as much of the chemical energy in coal as possible into "pure hydrogen", whilst capturing a good proportion of the $CO_2$, will have to be rather different to current IGCCs. Hence before going into the specifics of the design of an IGCC suitable for HYPOGEN type plants, it is worth reviewing the characteristics of current IGCC examples and concepts, to see how closely they meet the requirements for a HYPOGEN facility. A key factor in the design of an efficient and economic IGCC plant is the specification and design of the gas turbine and heat recovery system. This is a serious issue even with standard natural gas fired CCGT plants and some of the more important issues are discussed in Appendix 2.

The characteristics of various types of gasifiers will be dealt with more detail in a separate report, but in terms of converting coal to syngas, the "cold gas efficiency" is of critical importance. This figure is defined as the calorific value of the raw, untreated gas from the gasifier divided by the calorific value of the coal used to produce that gas [41]. A high cold gas efficiency implies that the gas contains a large fraction of $H_2$, CO and hydrocarbons. The hydrogen in the syngas does not require conversion, of course, but the CO and hydrocarbons can be used to produce additional hydrogen. Conversely, a low cold gas efficiency would indicate a high $CO_2$ content in the raw gas. Also, clearly of importance in a HYPOGEN gasifier is the ability to convert all of the coal into gas. As noted earlier, this is not necessarily the case with certain types of fluidised bed gasifiers, since reaction temperatures are too low.

### 4.1.3 IGCC Gas Turbines and Fuel Gas Purification Status and Implications for HYPOGEN

Gasification and fuel gas pressures are moderate in IGCC plants, as these only need to be sufficient to inject the gas into the combustion system of a gas turbine unit. At the present time, the highest-pressure ratio in an industrial gas turbine is that of the Alstom intercooled/reheat GT 24/26 which is 38/1. This would call for a fuel gas pressure of 46 bar. Given likely gasifier pressure drops, this implies a gasifier pressure of 50-55 bars, which begins to limit the options to slurry fed gasifiers. For a more conventional gas turbine of the GE Frame 9H type, pressure ratios are now up to 23/1. The latter is well within the range of most gasifiers, and indeed many projects use a fuel gas expander to gain extra energy. But a hydrogen plant would need to deliver hydrogen at pressures of between 70 and 100 bars to avoid the need to compress hydrogen at the plant gate. It follows that the designs for pressure vessels and some heat exchangers would need significant changes compared to current IGCC systems.

With respect to gas treatment, the main concern in IGCCs has been to remove dust, sulphur and chlorine compounds to protect gas turbine blading, although ammonia and hydrogen cyanide also need to be eliminated to help reduce $NO_x$ emissions. Some of the sulphur in the coal appears as COS rather than $H_2S$, which is somewhat difficult to remove with many acid gas removal processes. Accordingly the tendency has been, in earlier IGCC concepts to neglect COS, as its contribution to the sulphur emissions is only around 5% [42, 43, 44]. In future, tighter control on emissions, and possible problems with ammonium sulphate formation in the final sections of an HRSG (if a selective catalytic reduction unit is specified) would point to require complete removal of COS. This would also be a requirement in a plant producing hydrogen.

In conventional IGCC, the inerts, that is non-combustible gases, which include $CO_2$, provide a considerable source of pressure energy in the gas turbine; hence they are left in the fuel gas. The need to retain $CO_2$ in the fuel gas greatly influences the choice of acid gas removal systems. The favoured option for current IGCCs is that of MDEA (Methyl-Di-Ethanol-Amine) as it absorbs $H_2S$, whilst taking out very little $CO_2$. However the picture would change completely in HYPOGEN type IGCCs where the intention is to capture the carbon dioxide, for subsequent storage, and to produce hydrogen of an acceptable purity. It follows that a two stage acid gas removal system would be needed in a HYPOGEN plant, the first stage to remove hydrogen sulphide and the second stage to capture the $CO_2$, although the same solvent would be used in both stages.

## 4.2 Air Blown IGCC Plant

The air blown IGCC plant is the simplest type of gasification combined cycle unit. Compressed air, as the oxidant, is blown into the gasifier, in effect partially combusting the coal. Some steam may also be added, as the endothermic reaction of the steam with carbon will prevent local overheating of the bed. Figure 8 shows the configuration of a typical air blown IGCC, which when producing electricity can be extremely efficient. A Mitsui Babcock paper indicates that the efficiency of a fluidised bed, air blown system is much superior to oxygen blown entrained bed gasifiers [45]. See Table 4. This probably results from the elimination of the air separation unit for oxygen production. The problem is that with low temperature fluidised bed, much of the coal has to be combusted as a char, so that a completely separate system is needed to capture the $CO_2$ from this section of the plant.

It might be argued, however, that it would be possible to construct an air blown entrained bed, high temperature gasifier in which all the coal is gasified, and which could capture carbon dioxide. In so doing, this concept would retain all of the advantages that it has over oxygen blown IGCCs, giving low capital costs and elimination of the energy-consuming ASU. The question is what are the prospects for an air blown IGCC, which is intended to produce hydrogen, rather than electricity?

**Table 4: Mitsui-Babcock Comparison of Efficiencies and Electricity Costs of Coal to Electricity Systems [based on Ref 45]**

| Plant | Efficiency | Capital Investment (€/MW) | Cost of Electricity (€/MWh) |
|---|---|---|---|
| **Supercritical Steam Power Plant** | 41.7% | 810 | 31.5 |
| **Circulating Fluidised Bed Power Plant** | 39.2% | 985 | 39.5 |
| | | | |
| **Airblown Fluidised Bed IGCC** | 46.9% | 935 | 37.5 |
| **Dry Feed Entrained Bed IGCC** | 43.3% | 1210 | 42.0 |
| **Wet Feed Entrained Bed IGCC** | 41.0% | 1230 | 43.4 |

An air blown, fixed bed gasifier might be a better prospect. Much of the heat that is generated in the gasifier would be recovered as the reaction products pass upwards through the mass of coal. In consequence, less carbon and oxygen would be wasted, heating up the nitrogen. The difficulty with fixed bed designs is that as the coal descends down towards the reaction zone, or hearth of the gasifier, much of the coal will pyrolyse to form gaseous hydrocarbon, tars, and phenols. The gaseous hydrocarbons, principally methane, can be left in the syngas as they add to its calorific value, but the tars and phenols would need to be removed. However, if the aim was to use the syngas to produce hydrogen all of these constituents would have to be eliminated.

A modest improvement in the performance of fixed and fluidised bed systems could be attained using a greater degree of preheating of the air. This would enable the airflow to the gasifier to be cut down, as less carbon would be needed to be burnt to bring the nitrogen up to temperature. Some preheating was done on the fluidised bed gasifier at Pinon Pine, the inlet temperature of the air being set at 340°C [47].

Even this only got the cold gas efficiency to 62%, in spite of a low gasifier outlet temperature of 980°C. The limit for preheating at present would probably be around 600°C, with at least some of the heat being abstracted from the outlet exhaust gas from the gas turbine, in preference to the exhaust being used for steam raising.

Although an air blown design eliminates a major capital cost, the energy absorbing ASU, the greater volume of gas flow will double the size of the downstream plant compared to an oxygen blown plant. There may be some advantages for the gas turbine, as the current approach is to dope the fuel gas with a large amount of nitrogen to reduce the flame temperature.

As noted earlier, the syngas, in air blown IGCC, could be shifted to produce carbon dioxide, which could then be captured. But it seems likely that the associated loss in efficiency will be greater than with an oxygen blown gasifier. The presence of nitrogen would damp down the temperature rise, which occurs during shift, reducing the chance of producing high grade steam. For an IGCC that was to produce hydrogen, the reduced temperature in the shift reactor might be considered an advantage, as this would promote the formation of hydrogen.

In practice any advantage that air blown, have over oxygen blown systems would be completely outweighed by the low hydrogen content of the gas, even after removal of $CO_{2.}$ Whereas at this point in the gasification process, with oxygen blown systems, the hydrogen level would be at least 90%, with an air blown gasifier, hydrogen levels are unlikely to exceed 50%. The bulk of the remainder will be, of course, nitrogen. The only practical means of separating hydrogen from nitrogen would be via a cryogenic route. This need to put a cryogenic plant onto the back end of air blown gasifier eliminates one of the main advantages of air blowing over oxygen blown systems, that is, the elimination of an ASU.

The vapour pressure curve for liquid nitrogen suggests that given a high gasifier pressure, that is 100 bars, cooling down to –196°C, the “normal” boiling point of liquid nitrogen could reduce the nitrogen concentration to 1%. It is difficult to get much below this level as nitrogen solidifies at -210°C. The level of cooling would not eliminate all of the carbon monoxide, the vapour pressure of this gas being only slightly lower than that of nitrogen [48]. There are even more practical issues with cryogenic separation. All cryogenic plants rely on a pressure drop to induce liquefaction. This is accomplished through a combination of Joule Thompson expansion, through a valve, and/or by causing the gas to do work in an expander. The need to separate the nitrogen, at high pressure, precludes this approach. It would in fact imply building another cryogenic plant to provide liquid nitrogen as a cooling medium.

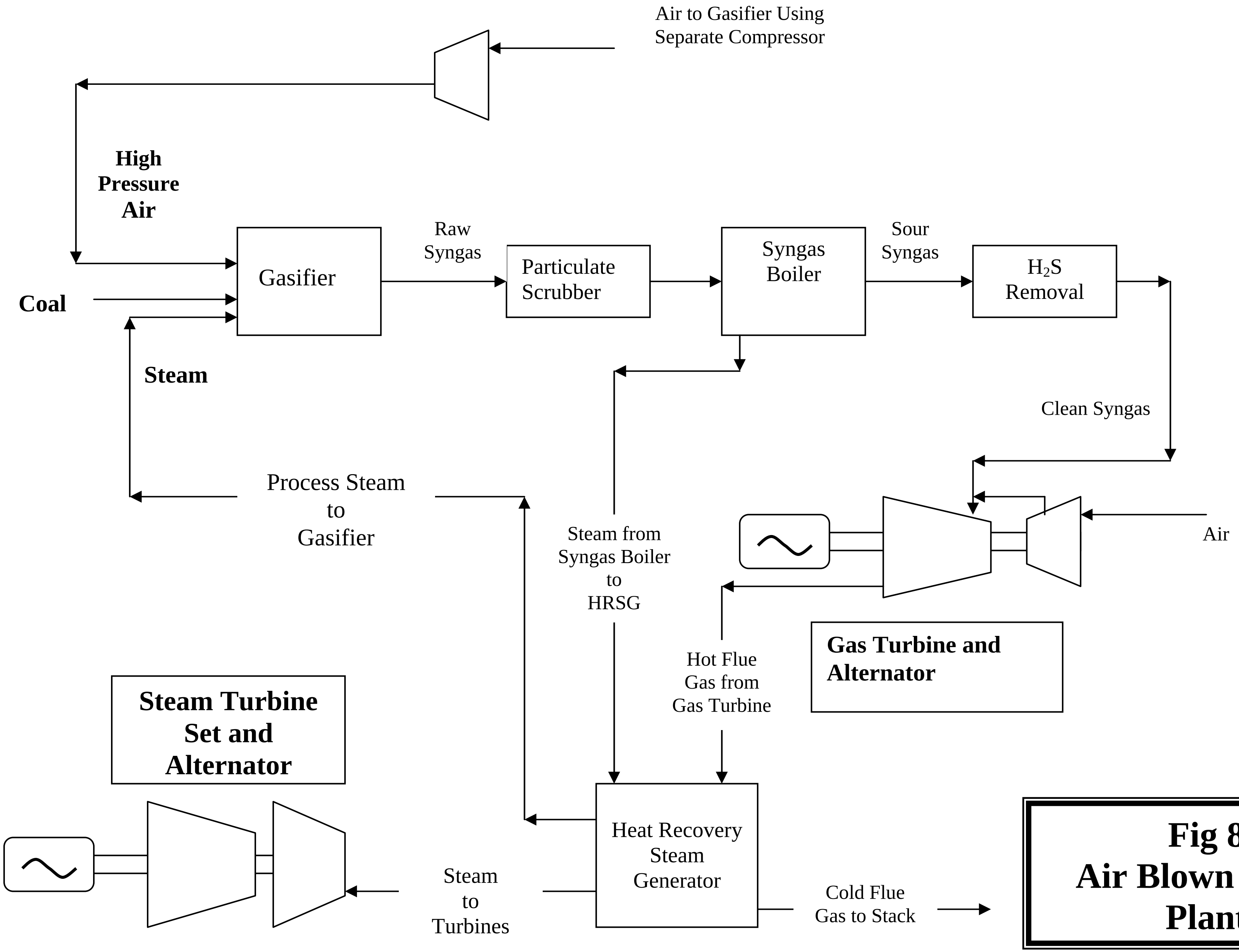


**Fig 8**
**Air Blown IGCC Plant**

To summarise air blown gasification is not suitable for hydrogen production since:

- **Cold gas efficiency is far too low**
- **The types of gasifier that need to be used will not gasify all the coal**
- **The cryogenic plant is likely to exceed the cost of an ASU on an oxygen blown IGCC plant**

### 4.3 Oxygen Blown IGCC Plant

The oxygen blown IGCC has come to be the standard approach for the integration of a gasifier with a combined cycle plant. The cold gas efficiency is higher than in air blown systems and the absence of large amounts of nitrogen reduces equipment size [46, 49]. Against this must be set the power demand of the ASU plant and the need to integrate this with the gasification process. See Figure 9. This shows that either steam or water can be used in the gasification reactions. In addition the nitrogen from the ASU may be used to dilute the syngas to the gas turbine to improve combustion properties.

There is a wide range of possibilities in terms of integration. Fixed bed units of the Lurgi and British Gas-Lurgi types, with a high cold gas efficiency, can be situated a long way from the CCGT plant. Such gasifiers can be shut down for a relatively long period as the reaction zone stays hot [50]. A CCGT plant making use of the syngas could be situated at the end of a pipeline, with the pipeline acting as a large storage system, enabling a gasifier to run at base load all of the times, despite changes in the electricity demand. As mentioned earlier, however, the gas from fixed bed systems contains relatively high levels of hydrocarbons. For this reason they are considered by some authorities as not being ideal for the production of hydrogen [51]. This is certainly true of some types of fixed bed gasifier. However, in the slagging form of fixed bed, it would be possible to inject the methane, tars and phenols into the high temperature hearth zone, where these components would react with steam and oxygen to form CO and $H_2$.

The higher the level of integration the more efficient will be the plant. The drawbacks to full integration are more difficulties with start ups, greater potential for a series of equipment failures after an unexpected plant shutdown, and, in general, less flexibility in control of plant output. This lack of flexibility is clearly critical to an IGCC that is intended to vary the energy output between electricity and hydrogen as well as being able to run at part loads.

Some of the forms of integration on an oxygen blown IGCC power generating plant are given below. (An air blown gasifier would have the steam systems in common, and might also take air off the compressor on the CCGT plant gas turbine for use in the gasifier).
The differences between the amount of integration in a conventional IGCC and those intended to produce hydrogen and electricity will be covered at appropriate sections in this report.

- **Plant Electrical Demand**

All or most of electrical power for ancillaries is self-generated on site

- **Air Separation Unit**

Some or all of the compressed air for the ASU is taken from gas turbine
Nitrogen from ASU to gas turbine combustor for $NO_x$ suppression
Nitrogen from ASU for lock hopper
Nitrogen from ASU for coal transport
Nitrogen From ASU for acid gas stripping

- **Steam and Water System**

Common water treatment for steam production for steam turbines and gasifier
Common steam drums for HRSG and Gasifier generated steam
Where practical, superheated steam from HRSG and Gasifier mixed
Extracted steam from turbines used for gasifier process steam
Gas turbine compression heat used for feed heating of boiler water
Heat from Claus Plant for $H_2S$ conversion to sulphur used for feedheating of boiler water
Steam for stripping acid gases is taken from the steam system

- **Fuel Gas**

Preheating of fuel gas by steam or boiler water
Fuel gas may be saturated with steam to reduce $NO_x$
Fuel gas may be expanded to generate additional power

The development of gas turbines may result in further integration and implication for heat recovery from the gasifier process train. As noted in the section on CCGTs, more advanced industrial turbines are now using steam cooling for hot section components. Furthermore if intercooled gas turbines are used in the IGCC field, this will offer a new source of heat from the intercoolers.

More importantly, as a factor governing the design of the steam system is that the pressure levels and degree of superheating in modern CCGT plants are now much higher than can be produced from the gasifier heat train. For example the steam system in an Alstom GT 26 based CCGT runs at 110 bar pressure at 566°C. The HRSG associated with the new GE Frame 7001MS H gas turbine also operates at 566°C but runs at a pressure of 124 bar.

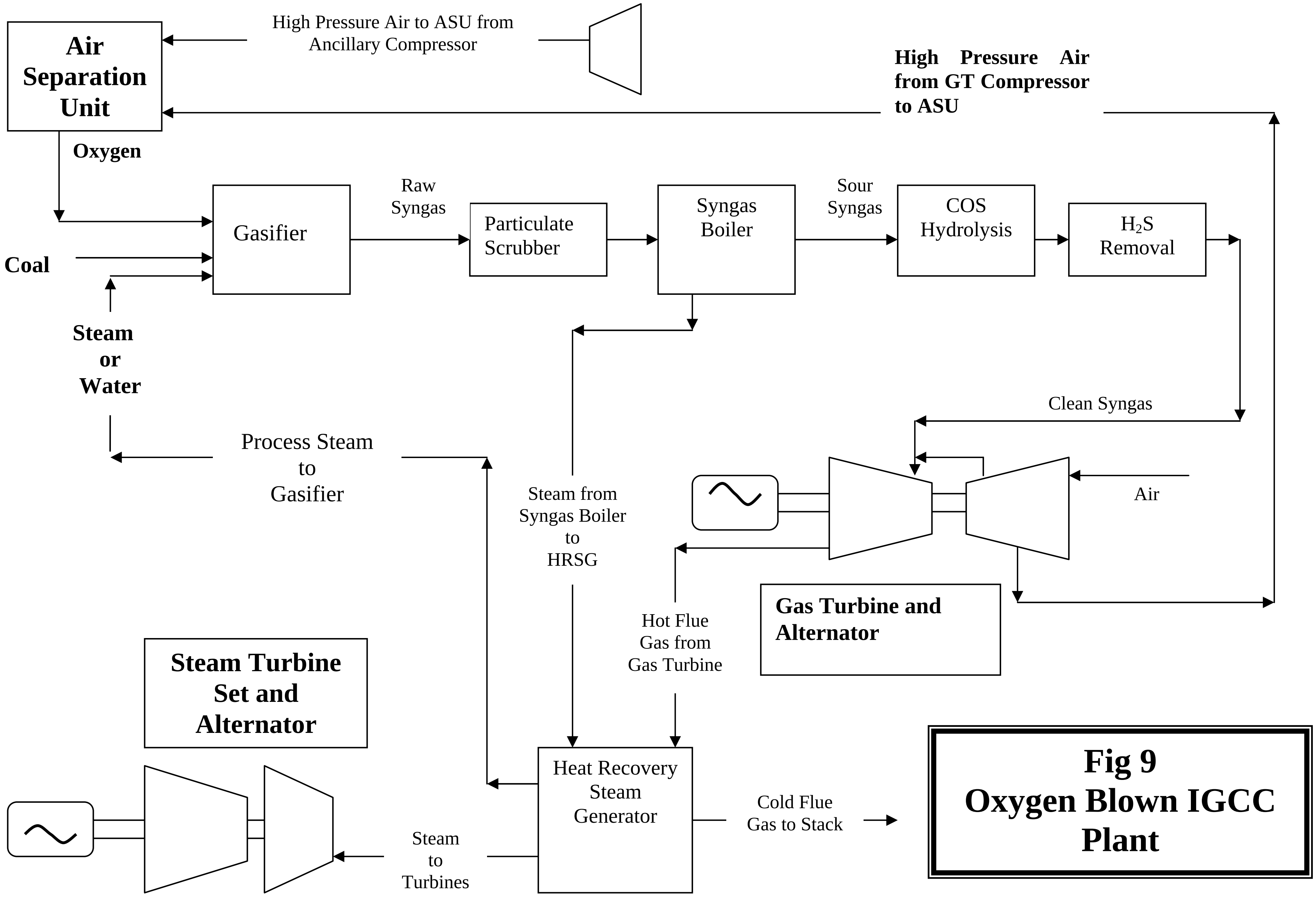


**Fig 9**
**Oxygen Blown IGCC Plant**

There is debate about the optimum level of integration on IGCC systems, covering the sets of equipment detailed above and how they might be used. Most of this discussion is in-house by the various contractors, but a distinct view is emerging on the level of integration of the ASU. The consensus seems to be that at least some of the air for this should be supplied from the gas turbine compressor. If all the air to the ASU were to come from the gas turbine this would represent up to 15% of the compressor airflow. A paper from Foster Wheeler indicates that net plant output is at a maximum when 50% of the airflow is from the compressor, although it is admitted that, in practice, much depends on the characteristics of the gas turbine. In this study the modelling was based on GE 9001 FA [52]. The contrary view is that of Siemens who are already using 100% integration at Buggenum [53]. Siemens admit that supplying all the air from the gas turbine does reduce plant flexibility and increases start up times. They suggest that these drawbacks can be overcome by making use of liquid oxygen and nitrogen from a store, and by using an ancillary compressor to supply air to the ASU during the initial phases of plant start up. It is understood that in a heavy oil based IGCC in Sardinia, it was found more beneficial to produce the oxygen from a completely separate ASU.

These arguments have some implications for a HYPOGEN plant, as the ideal situation is to close down power production when there is no electricity demand. This would imply the need to shut down the gas turbine at such times. In consequence, there would then be a need for a separate compressor for the ASU, which is contrary to most thinking.

The ASU can be integrated with the plant in other ways. Nitrogen is used as a purge gas for lock hoppers and is also used as a transport medium for coal in the Shell and Prenflow gasifiers. A more important use is as a diluent in the fuel gas to the gas turbine to reduce flame temperatures and suppress $NO_x$. In so doing the calorific value of the gas is reduced to half. For this reason there is little point in providing oxygen of a very high purity in conventional IGCC plants. In the Shell process, for example, the fuel gas can have up to 4% nitrogen. This would be quite detrimental in the HYPOGEN facility, where hydrogen of a reasonably high degree of purity is required.

This raises the question of whether there is a potential use for the nitrogen in a HYPOGEN plant, when only hydrogen is being produced. The quantities used as a diluent in present designs of gas turbines are large. The Foster Wheeler paper, although based on an IGCC fuelled by visbreaker tar, indicates that with a fuel input of 4423 tonnes per day, the nitrogen supply to the gas turbines amounts to almost 70 tonnes per hour. This however would be a fraction of the tonnage of waste nitrogen which has to be released to the atmosphere during the production of oxygen, which would typically be up to three times the coal input to the gasifier.

### 4.4 IGCC with $CO_2$ Capture

There are two basic options for an IGCC which is intended to produce electricity only, but must also capture the carbon dioxide. With “precombustion capture” the carbon monoxide in the syngas is reacted with steam in a shift converter, converting this to hydrogen and carbon dioxide. The $CO_2$ is then removed in an acid gas wash. The fuel gas, now consisting largely of hydrogen, is burnt in the CCGT gas turbine. This is essentially the basis for a HYPOGEN type plant as has been discussed in this report, and as the term “precombustion capture” suggests, the carbon dioxide is captured before the fuel gas is burnt. An important difference between capture type IGCC and HYPOGEN plants is that, in the former, not all of the $CO_2$ is captured. So as to increase power output, up to 15% of the $CO_2$ is released to the atmosphere, as this reduces capital costs and improves efficiency. In a HYPOGEN plant since the hydrogen would have to have a reasonably high purity, above 98%, more $CO_2$ has to be captured, even if this is detrimental to the efficiency and output of the plant.

### 4.4.1 Post Combustion Capture of $CO_2$ from IGCCs

The alternative, “post combustion capture” process is to remove the $CO_{2,}$ which is formed after the purified syngas (which mainly consists of $H_2$ and CO) has been burnt. This procedure is carried out after the flue gas has been cooled to room temperature after passing it through an HRSG. An MDEA alkaline solution would be used for capture of the $CO_2$, but since the absorption is carried out at atmospheric pressure it is difficult to remove all of this gas. As pointed out, in Sections 2.2.1 and 2.2.2, post combustion capture appears to have certain advantages in terms of electricity production. Hence, in principle, the electricity from such a post combustion capture IGCC could be used to electrolyse water for the production of hydrogen. There would, however, be significant energy losses, both in the electrolysis process itself, and in the energy needed to compress the hydrogen up to pipeline pressure.

A post combustion capture system could conceivably be used in a HYPOGEN plant whereby membrane separation would be used to produce a hydrogen rich stream, from the purified syngas for sales to the hydrogen consumers. The other stream at high pressure would have a high concentration of carbon monoxide and would be used as the fuel input to the gas turbine. Post combustion capture would then be applied to the flue gases after they had passed through the HRSG, as described above. One obvious drawback is that syngas only contains about 30% hydrogen, this restricting the amount of hydrogen that the plant will produce. A much more fundamental criticism of such a plant is that it would be operating with a ratio of hydrogen-to-electricity that could never rise above about 1 to 2. Furthermore, the higher the purity of the hydrogen stream, the lower will be its pressure, and as has been emphasised, a high outlet pressure from the plant is vital for long distance transmission. High volume hydrogen compressors are not yet available.

To maintain the hydrogen stream at high pressure, a possible option would be to remove the carbon monoxide, which will represent about 60-70 % of the gas stream, using liquid absorbents [54]. The options are the well-established copper-ammonium salt process which uses a water based solvent, and the somewhat more recent COSORB process which uses a toluene solvent containing cuprous ammonium chloride. In both of these the hydrogen appears as a high pressure stream, but the carbon monoxide is at ambient pressure. Although, because of its high density, there is no problem is bringing the carbon monoxide up to a pressure suitable for combustion in the gas turbine, this is likely to result in a substantial energy demand and loss in plant efficiency.

### 4.4.2 Precombustion Capture of $CO_2$

Precombustion capture has the merit of being less complex route for the production of hydrogen and electricity. However, it will become clear that even a precombustion IGCC concept will require some modification, if it is to be used in a HYPOGEN facility. As discussed earlier, the main feature of this mode of capturing $CO_2$ is to react the carbon monoxide in the syngas with steam in a shift reactor, and then to absorb the $CO_2$ which is produced in alkaline solutions.

In this process the carbon oxysulphides (COS), in the raw gas hydrolyse, in the shift reactor to form $H_2S$, avoiding the need for a separate COS unit [53]. The HYPOGEN facility could be similar to an electricity producing IGCC, with nitrogen from the ASU being used to improve the burning characteristics of the hydrogen rich fuel gas. The most obvious change, as indicated earlier, is that a different acid gas removal system would need to be used. See Figure 10.

The shift reaction is quite exothermic giving a temperature rise in the converted gas of up to 140°C, depending on the amount of carbon monoxide that is available. The heat that is produced can be used for steam raising. It can be shown that only one shift reactor is required as the intention is not to convert all the CO to $CO_2$.

An additional factor, which will be covered in more detail in a subsequent report, is the suitability of various designs of gasifier for carbon capture IGCC based processes, whether these are intended to produce electricity only, or are of the HYPOGEN type. This aspect needs to be mentioned here, however. It is commonly agreed that the electrical efficiencies of entrained bed IGCCs, in which the slag is solidified through the recirculation of cold gas, are superior to “quench gasifiers”. The latter solidify the slag by injecting water into the hot syngas coming from the reactor. This process degrades the heat in the syngas, reduces steam generating potential and overall reduces output and efficiency. Their main advantage is that capital costs are lower.

The situation changes to some extent when the syngas has to be shifted to remove carbon monoxide as a precursor to $CO_2$ capture. Here the water which has been added to the quench gasifier, much of which will have turned to steam can be utilised in the shift reaction. Furthermore in the quench gasifier, some further improvements could possibly be made by adding a desaturator downstream of the shift reactor. This picks up much of the heat from the shift reaction, in the form of hot pressurised water, which is used in the quenching the gasifier slag. The result is that the partial pressure of steam into the shift reactor is increased, favouring the shift reaction. Overall temperatures out of the gasifier and shift reactor are raised enabling steam at higher pressure to be produced in syngas and shift converter boilers, which should improve electricity production [55].

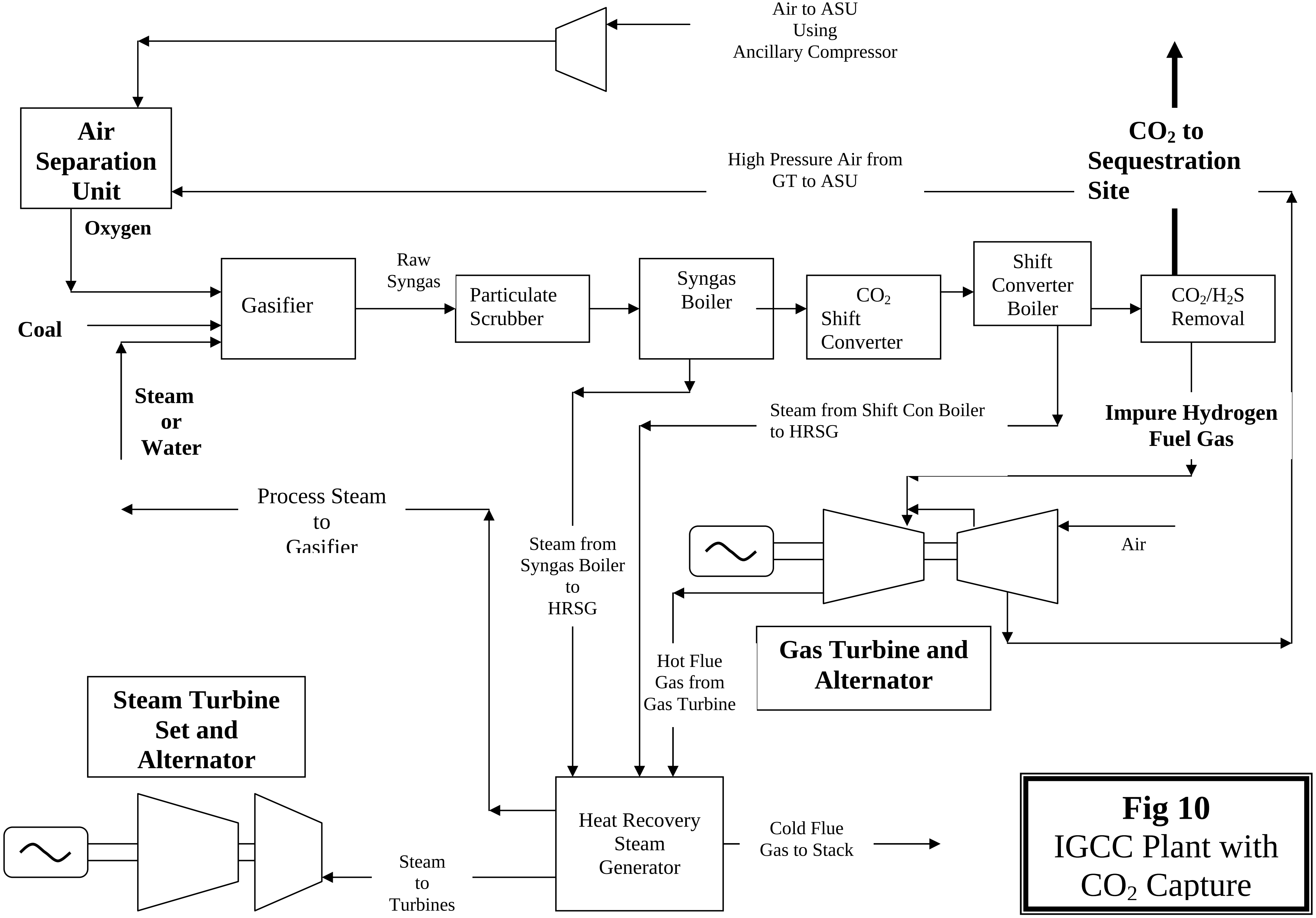


**Fig 10**
IGCC Plant with CO$_2$ Capture

## 4.5 A Carbon Capture IGCC Plant for Hydrogen Production and Electricity Generation

The previous sections were intended to review generating systems whose technologies and equipment choices could be considered for use on an IGCC plant that was to produce hydrogen as well as electricity. These systems have been subjected to critical scrutiny, so as to eliminate gasifier designs and equipment concepts that would not be suitable in a hydrogen producing scheme. To summarise fluidised bed systems are not a good choice as much of the coal is left in the form of char, which has to be used for the generation of electricity. A fixed ratio HYPOGEN design would result. Similarly, a post combustion type gasification system would in practice result in a fixed electricity to hydrogen ratio HYPOGEN. Finally, any type of air blown gasifier must also be rejected, as this will give a low cold gas efficiency, the disadvantage of having to remove the nitrogen using a cryogenic process. At the present time, therefore, an oxygen blown fed entrained bed type of gasifier would appear to be the best option.

Figure 11 shows a schematic of the plant, which as shown incorporates a PSA system for producing highly purified hydrogen. As explained in Section 2, the use of conventional PSA is detrimental to hydrogen production efficiency and ideally should be superseded by alternative purification processes. It is possible, however, that if there was a shortage of steam for producing power for ancillary equipment, as discussed below, the tail gas from the PSA could either be used for enhancing steam production or increasing the steam superheat. Both approaches would increase the power output of the steam turbines that would be needed at times when the gasifier runs in the “stand-alone” mode. Hence Figure 11 shows this feature.

The main demands for electrical power are those of the ASU (as would be required on all oxygen blown IGCC based system), and those which originate from the need to compress the captured $CO_2$ for transmission by pipeline to the storage site. Both process flow modelling and data from equipment manufacturers is needed to estimate these demands accurately, but reasonable estimates can be obtained from the literature as described in the following sections.

### 4.5.1 ASU Power Demands

As discussed in Section 2, unless this type of plant is confined to niche markets where there is a big demand for hydrogen, it is essential that the plant should be able to switch from hydrogen to electricity. This is likely to have strong implications for the amount of integration between the steam generated from the gasification and shift reactions and the combined cycle section of the plant. It also affects the design of the ASU and the feasibility of capturing $CO_2$. Unfortunately the breakdown of energy use on IGGC systems is not generally available. Even the power from a gas turbine is likely to be different to output when the same machine is used on a natural gas fired CCGT plant, because of the difference in mass flows. Holt, however, has provided the outputs of the steam and gas turbines, and the auxiliary power demand for four types of coal based IGCCs. Table 5 is based on his paper [9].

These figures give some indication of how easy it is going to be to convert an IGCC to a HYPOGEN plant, without a radical change in plant configuration. Would there then be sufficient electricity from the steam turbines, which use the steam produced from the waste heat from the gasification and shift reactions, to power the ancillaries on the plant? This is a substantial demand, as Table 5 shows. Even without the energy needed to compress the $CO_2$, ancillary power demand can be up to 25% of the output. Note that in two of the plants, all the air to the ASU comes from the gas turbine, in the other plants, it is supplied from a separate compressor.

**Table 5: Fuel Demand and Power Output of IGCC Plants [From Ref 9]**

| Plant (Country) | Feedstock | Throughput (tons/day) | Ancillary Power Demand | Output | Efficiency (LHV) | Air to ASU |
|---|---|---|---|---|---|---|
| **Buggenum (Netherlands)** | **Coal** | **2000** | **31 MW** | **252 MW** | **43.0%** | **From GT** |
| **Puertollano (Spain)** | **Pet Coke and Coal** | **2600** | **35 MW** | **300 MW** | **42.2%** | **From GT** |
| **Tampa (USA)** | **Coal** | **2200** | **63 MW** | **250 MW** | **41.2%** | **Separate Compressor** |
| **Wabash (USA)** | **Coal or Pet Coke** | **2500 or 2000** | **35.4 MW** | **262 MW** | **39.2%** | **Separate Compressor** |

Unfortunately only a rough estimate can be made of the energy which might be produced from the steam turbines. This is because, in an IGCC, the steam from the heat exchangers in the gasifier train is integrated with the steam produced in the gas turbine HRSG. In contrast to an HRSG on a combined cycle plant, where most of the heat in the gas turbine exhaust is being used to boil water, in an IGCC plant much of the heat in the gas turbine exhaust is being used to superheat the steam. Hence the usual rule of thumb, that on a combined cycle plant, the steam turbine produces about 50% the power of the gas turbine cannot be applied to IGCCs. (More information about HRSG design and operation is given in the Appendix 2).

Accordingly Table 6, also based on the data supplied by Holt in the aforesaid paper, shows the contribution that the steam system from the gasifier makes to power generation, on the assumption that the heat from the gas turbine only supplies about 40% of the steam turbine power (STP) in an IGCC. The table also shows whether the gasifier steam system can provide enough power to run the ancillaries. This seems to be the case with Buggenum and Puertollano, but not at Tampa or Wabash.

**Table 6: IGCC Gas and Steam Turbine Energy Output and Ancillary Plant Demand**

| Plant | Gas Turbine Output (MW) | Gas Turbine STP Contribution (MW) | Steam Turbine Output (MW) | Gasifier STP Contribution (MW) | Ancillary Power Demand (MW) | Excess Electric Power (MW) |
|---|---|---|---|---|---|---|
| Buggenum | 155 | 62 | 128 | 66 | 31 | 35 |
| Puertallano | 200 | 80 | 135 | 55 | 35 | 20 |
| Tampa | 192 | 76.8 | 121 | 44.2 | 63 | -18.8 |
| Wabash | 192 | 76.8 | 105 | 28.2 | 35.4 | -7.2 |

Although Table 6 indicates that there is no consistent trend on whether a converted IGCC would be producing an excess of power or whether there would be a need to import electricity, it does seem to show that there is no big surplus or deficit compared to the net output of the plant.

Table 7 approaches this question in another way. Here the assumption is made that, given a cold gas efficiency for the plant of 80%, the deficit of 20% appears as steam. It is also assumed that this steam can be transformed into electrical energy at an efficiency of 33%. This latter figure may be considered to be on the low side, but much of the steam that is produced will be at medium pressure, with only a small amount of superheating being possible because of syngas side corrosion problems with heat exchangers.

**Table 7: Likely Power Production from Stand Alone IGCC Steam Plant**

| Plant | Fuel Input (MW) | Gasifier Waste Heat Available (MW) | Gasifier Steam Turbine Power (MW) | Ancillary Power Demand (MW) | Excess Electric Power (MW) | Proportion of Energy Input (MW) |
|---|---|---|---|---|---|---|
| Buggenum | 586 | 117.2 | 38.9 | 31 | 7.9 | 1.3% |
| Puertallano | 710 | 142 | 46.7 | 35 | 11.7 | 1.6% |
| Tampa | 606 | 121.2 | 40.0 | 63 | -23 | -3.8% |
| Wabash | 668 | 133.6 | 44.1 | 35.4 | 8.7 | 1.3% |

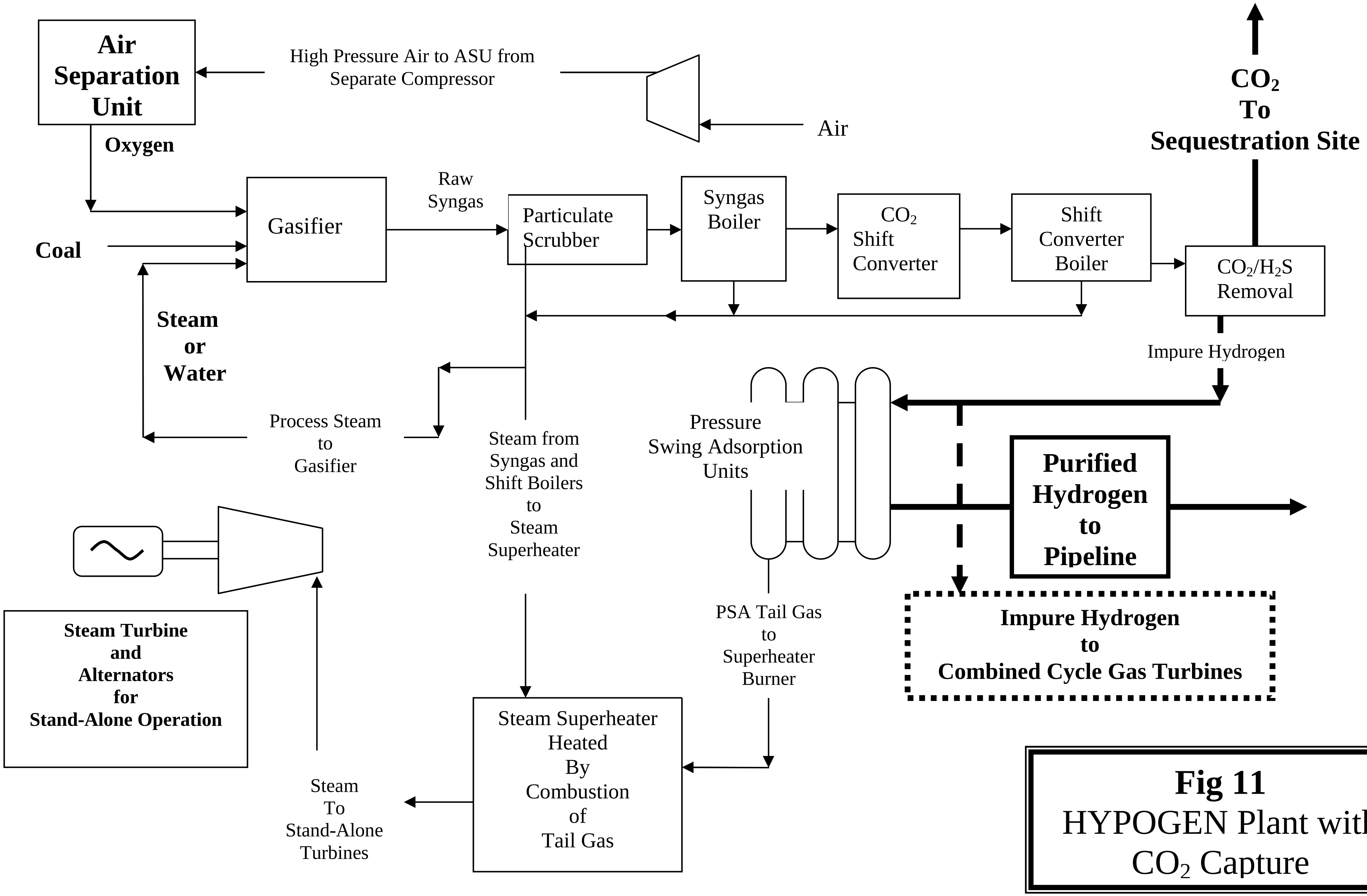


**Fig 11**
HYPOGEN Plant with $CO_2$ Capture

Table 7 suggests that excess or deficit in power generation is likely to be within a few percent of the plant output. The principal additional demand for power, which is not considered in any of these calculations, is the power required to compress $CO_2$, This issue is discussed in more detail in Section 4.5.2. The implications are therefore, that some of the hydrogen, which the plant produces, will have to be used to provide some additional power.

Some further figures indicate the likely level of power demand of an ASU, which represents one of the biggest users on the plant. For a visbreaker tar based IGCC, with a power output of around 800 MW, workers at Foster Wheeler state that the air compressor power is about 70 MW, that is about 8.75 MW per 100 MW of plant output. In this particular example about another 6.5 MW per 100MW is needed to send oxygen to the gasifier and nitrogen to the gas turbine combustor [52]. Very roughly about 15 MW is needed to run the ASU unit and supply the gas to the plant. Because of the high gasifier pressure on an IGCC-HYPOGEN plant, the demand is likely to be about 20 MW per 100MW output.

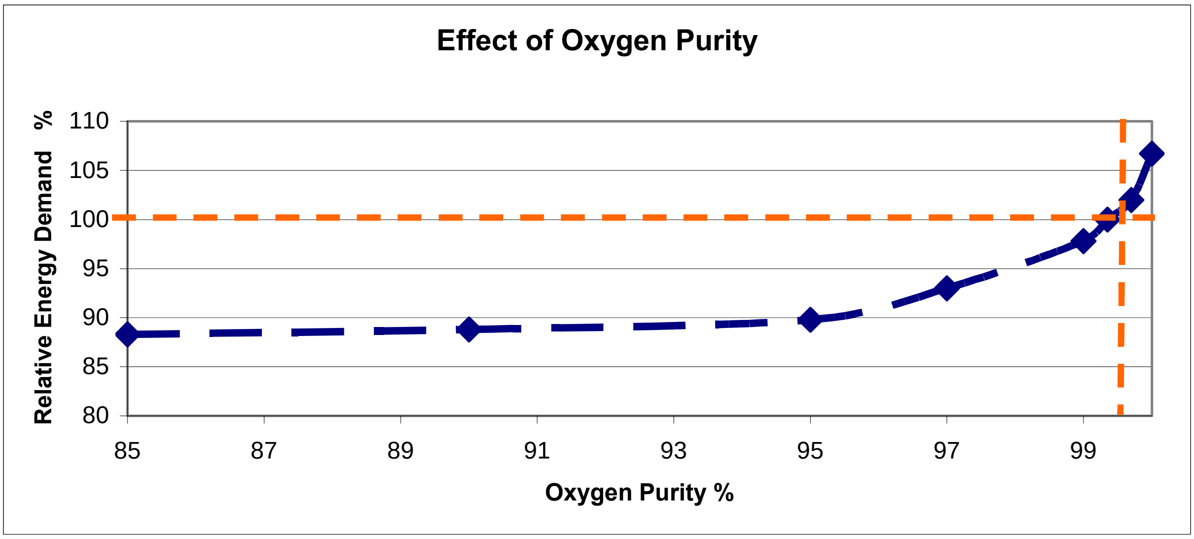
**Table 8: ASU Power for Shell and Texaco IGCC Units [56]**

| Gasifier | Pressure (bar) | ASU Integration | Gross Plant Output (MW) | Net Plant Output (MW) | Ancillary Demand (MW) | ASU Demand (MW) |
|---|---|---|---|---|---|---|
| **Shell A1** | 39 | 50% | 910 | 776 | 134 | 100 |
| **Shell A2** | 61 | 50% | 895 | 748 | 147 | 113 |
| **Shell B1** | 39 | 30% | 896 | 709 | 187 | 113 |
| **Shell B2** | 39 | 30% | 875 | 687 | 188 | 114 |
| **Shell B3** | 39 | 30% | 883 | 720 | 163 | 113 |
| **Shell B4** | 61 | 30% | 879 | 674 | 205 | 131 |
| | | | | | | |
| **Texaco C1** | 65 | 50% | 989 | 826 | 263 | 119 |
| **Texaco C2** | 65 | 43.2% | 1013 | 861 | 152 | 101 |
| **Texaco C3** | 39 | 50% | 954 | 780 | 174 | 116 |
| **Texaco D1** | 65 | 50% | 973 | 769 | 204 | 129 |
| **Texaco D2** | 65 | 50% | 980 | 783 | 197 | 131 |
| **Texaco D4** | 65 | 50% | 942 | 745 | 197 | 121 |

A study, done on behalf of the IEA, also by Foster Wheeler on the Shell and Texaco IGCC plants gives a similar figure in terms the ratio of the power needed for an ASU to the output of a plant [56]. Table 8 lists the figures for the various cases that were considered. The “ASU integration” refers to the proportion of the power, or air supply to the ASU that is taken off the gas turbine. It will be seen that the ASU is responsible for well over half of the power demand of the ancillaries. The level of these is not likely to change during the time when the IGCC is producing hydrogen only. The main difference would be a positive gain, in that the need to compress the nitrogen for the gas turbine disappears. From the Foster Wheeler figures this would be worth about 10 MW for a plant of the type analysed in the IEA Foster Wheeler Study.

The higher oxygen purity, needed by the HYPOGEN facility is likely to increase the power demand of the ASU even further. Fig 12 redrawn from Figure 3 in Section G of the IEA report mentioned above shows the general trend [56]. Note that at an oxygen purity of 95%, the relative energy demand is only 90% of that required at 99.5 %. Some of the increase will be due to the need to vent relatively impure oxygen so as to carry off impurities such as nitrogen and argon.

**Figure 12: Effect of Oxygen Purity on ASU Power Consumption [Redrawn from Ref 56]**



### 4.5.2 Power for $CO_2$ Compression

The other main parasitic power demand is the energy needed to capture the $CO_2$ and to compress it up to around 100 bar pressure for transmission to the sequestration site. If a chemical process were to be used for capturing the $CO_2$, most of the energy required is in the form of low grade heat for stripping the amine and for heating the reboiler (a boiler which is used to concentrate the absorbing solution, and which also provides steam for the stripping the $CO_2$). With chemical processes the $CO_2$ will be generated at atmospheric pressure, so that compression costs will be high, offsetting the benefits of only using steam for stripping. If a physical absorbent is used the heat requirements would be lower, but it is likely that refrigeration might be required to increase the absorption capacity. This would require electricity [57]. However some of the $CO_2$ could be released from the absorbent at above atmospheric pressures, reducing the energy needed for compression.

For IGCC that is intended to capture carbon dioxide, there is a fairly wide range of options for $CO_2$ removal, and this may account for the wide range of power needs that are given by various references. Table 9 shows the electricity required, as indicated, in the IEA report in which, apart from in one case, a physical solvent, Selexol was used [56]. Electrical consumption was projected to be about 60 kWh per tonne of $CO_2$, but the capture level was only 80-85%. Note that even with this capture level the compression power was almost 5% of the gross power output from the plant. Another study also commissioned by IEA, using Selexol, but with a nominal capture efficiency of 80%, also corresponds with the above figures of 60.5 kWh/tonne [58]. The electrical energy needed to run Selexol plant for $CO_2$ removal and that needed for $CO_2$ compression were 15.6 (mainly to recycle $CO_2$ rich flash gas from the $H_2S$ absorption section) and 19.7 MW respectively. This corresponds to about 8% of the plant output. In contrast a conventional IGCC would only need a relatively small amount of power to run a Selexol plant that only removed $H_2S$. The extreme end of the power requirements is given in a Princeton paper dealing with a plant which produces a one gigawatt hydrogen stream plus 30.9 MW of electricity for sales to consumers. Here using gas separation with Selexol, the estimated energy consumption to compress the $CO_2$ is 112 kWh/ tonne. [19].

**Table 9: $CO_2$ Compression Power for Projected 750 MWe IGCC Plants [From Ref 56]**

| IGCC Process | $CO_2$ Compression Power (MW) | $CO_2$ (Tonnes/ Hour) | Energy Required (kWh/tonne $CO_2$) | Type of AGR |
|---|---|---|---|---|
| | | | | |
| **Shell B1** | 32.6 | 550 | 59.3 | Selexol |
| **Shell B2** | 35.1 | 546 | 59.7 | Selexol |
| **Shell B3** | 36.6 | 550 | 66.5 | MDEA |
| **Shell B4** | 34.7 | 550 | 63.1 | Selexol |
| | | | | |
| **Texaco D1** | 38.5 | 626 | 61.5 | Selexol |
| **Texaco D2** | 39.8 | 627 | 63.5 | Selexol |
| **Texaco D3** | 35.5 | 589 | 60.3 | Selexol |
| **Texaco D4** | 39.2 | 626 | 62.6 | Selexol |

### 4.5.3 Implications for a Flexible IGCC-HYPOGEN Plant

The principal conclusion from Sections 4.5.1 and 4.5.2, which dealt with respectively, the power demands of the ASU for oxygen production, and the power required to capture and compress the $CO_2$ is that the power demands from the ancillaries on an IGCC-HYPOGEN plant are in excess of the electrical power that can be generated using waste heat from the gasifier. Some hydrogen will therefore have to be used to provide additional electricity. This does imply that it is possible, in principle, to design a flexible ratio HYPOGEN plant, but the figures for ancillary power demand indicate that this is a major source of plant inefficiency, which needs to be addressed.

## 5. Research and Development Aspects

It is clear from the foregoing that although it would be possible to construct a HYPOGEN plant based on present-day IGCC and steam reforming processes, R&D in this area is necessary. Some of this work would need to be initiated by contractors who have expertise in the design and construction of specific pieces of equipment. The R&D can also be divided into that which will be needed for the proposed HYPOGEN Test Facility and the follow-on plants that are directly based on this design. Other activities would have a longer term time scale and be related to improvements in the design and operation of more fully developed HYPOGEN plants.

### 5.1 R&D Relating to an IGCC Based HYPOGEN Test Facility

As noted above, consideration is being given to the construction of a HYPOGEN test facility. In deciding on the plant specification it is to be hoped that this report will helpful to those involved in this project. It is also understood that this future plant will make as much use of off-the-shelf equipment as possible. However, as this report has shown, if the HYPOGEN facility is to be the basis of a continuing line of more commercial developments, only a limited range of IGCC systems will be suitable, and even these will require development of much of the equipment. Some of the more vital issues, which will impact on the design, construction of the facility are discussed in this section of the report. The investigations related to these aspects will involve process flow modeling, but will also require close consultation with equipment suppliers to resolve potential difficulties.

#### 5.1.1 Assessment of the saturation technique to improve the efficiency of slurry based coal gasification

Because of the probable need to produce hydrogen at high pressure, it would appear that the only off-the-shelf option is the GE process (formally Texaco), as with this arrangement the coal can be introduced into the gasifier as water based slurry. This tends to have low cold gas efficiencies caused by the energy needed to evaporate the water in the slurry. In addition water is added to quench the gas and solidify the slag resulting in a further loss of available heat. However, as described in the text, a method has been proposed by which hot water is recirculated from downstream sections of the plant, which is reinjected to quench the hot gas exiting the gasifier [55]. The developers of this process also claim significant benefits when the technique is used in conjunction with shift conversion, as a route to hydrogen production and $CO_2$ capture.

However the concept appears to have been developed for an IGCC in which the hydrogen is intended to be used for electricity generation, with only 90% capture of the $CO_2$, work is needed to assess its potential for a HYPOGEN plant where the aim is to produce hydrogen with a much higher purity. The R&D activities would have to include an in depth process flow evaluation.

### 5.1.2 Problems with shift conversion at high pressure

The need to produce a high hydrogen content requires that the final stage of shift conversion be done at the lowest possible temperature (up to three separate shift reactors will be needed). However, the proportion of steam in the reactants determines, in part, the amount of conversion. With a high pressure process, in which the partial pressure of steam will be high, there will be some danger in the shift catalyst being wetted and degraded by the steam, if it starts to condense. If this were to happen, other than to accept that the amount of CO will be higher than desirable, the only possible option would be to remove some of the $CO_2$ before the final stage of shift is reached. Reducing the $CO_2$ level in the reactants would drive the reaction forward, as shown in the following equation.

$$\mathbf{CO + H_2O \longrightarrow CO_2 + H_2}$$

The process arrangements needed for this would be fairly complex. This is because of the need to cool down the gas after the second stage of shift to permit the $CO_2$ to be absorbed.  During cooling, most of the steam would condense, the condensate taking with it some $CO_{2,}$ as water dissolves this gas. After removal of the $CO_2$, the gas would need to be reheated to an appropriate temperature for the final stage of shift. The gas would also need to be re-humidified to provide a sufficiently high steam content. The arrangement of heat exchangers for heating and cooling the gas, and to utilise the hot $CO_2$ rich condensate would require a reasonably extensive process flow analysis study.

### 5.1.3 Hydrogen burning turbine

Development of a turbine capable of burning hydrogen without giving rise to high levels of $NO_x$ will be an essential part of the development of a HYPOGEN plant.

## 5.2 R&D Relating to a Steam Reforming Based HYPOGEN Test Facility

### 5.2.1 Provision of hydrogen rich gas for reformer furnace firing

To minimise the amount of $CO_2$ that might be released to the atmosphere, it would be essential to modify the steam reforming furnace to fire on hydrogen, rather than a mixture of natural gas and tail gas. The process analysis implications of this, which will require further investigations, would be:

- Significant increase in throughput of the sulphur removal system, steam reformer, autothermal reformer, shift converter and absorber etc

- Significant increase in size of steam system

- Change in the heat balance in the steam reformer heat recovery system

### 5.2.2 Design change in steam reformer furnace for hydrogen firing

If it was decided to base the plant on a conventional steam reformer, the change to hydrogen firing is likely to alter radically the thermal characteristics of the furnace, as hydrogen flames are much less radiative than those of natural gas. It seems likely that much less heat will be absorbed by the steam reformer tubing, resulting in higher flue gas outlet temperatures. This would require careful evaluation to ensure that the tubes run at the correct temperature. For the plant to be efficient it will probably also be necessary for the use, size and distribution of heat transfer equipment in the flue gas train to be revised.

## 5.3 Background research into HYPOGEN development issues

As was implied in the opening to Section 5.2, the proposed HYPOGEN Test Facility is very much a  large scale proof–of-concept plant, and will need to make use of as much off-the-shelf equipment a s possible. This will have some effect on efficiency and will compromise how such a plant can best serve the hydrogen economy. Longer term developments are required to enhance the capability of HYPOGEN systems. At this stage, the merits of these innovations seem clear, but these will require background research, probably then leading on the engineering development and test programms. R&D work of this type is described below.

### 5.3.1 HYPOGEN plant outlet pressure

Because of the limited capacity and efficiency of reciprocating compressors , which are at present the only practical means of compressing a low density gas, like hydrogen, to high pressures, it is difficult to transmit hydrogen economically over long distances. It follows that the exit pressure of hydrogen from a HYPOGEN plant needs to be very high. This helps overcome the relatively low energy content of hydrogen compared to natural gas. The ideal way of compressing gases for transmission in long distance pipelines is by using centrifugal compressors, as they are efficient low maintenance machines, but can only work on relatively high density gases. Unless the equipment is made complex by using, in effect, using several centrifugal compressors in series, it will not be possible to get a sufficient amount of compression.

At the present time most concepts that operate at really high pressure, that is 70-100 bar, are based on a water based slurry injected gasifiers. As noted these are not as efficient as those which use a dry coal feed. Due to problems in introducing ground coal into a gasifier, which operates at high pressure, these types are limited to about 30-35 bar. If it is decided to eventually opt for dry feed types, it will be necessary to develop a method of introducing the coal into a high pressure enclosure. The alternative is to use compressors at some suitable point in the HYPOGEN plant itself.

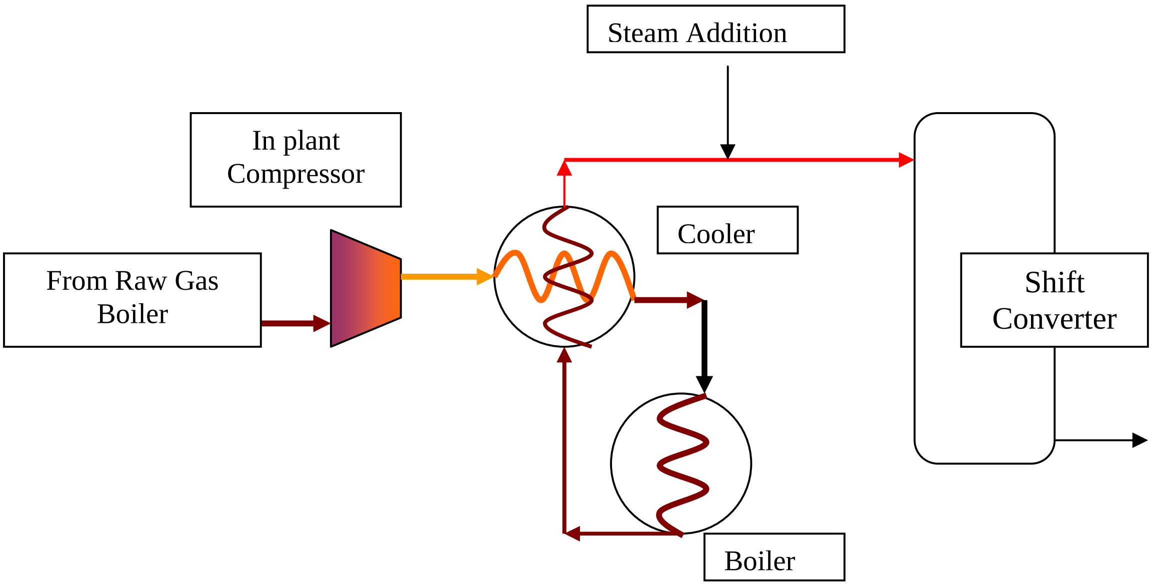


**Fig 13: Schematic Showing in Plant Compression**

Compression within the plant itself, before the syngas has been completely transformed to hydrogen may be a more efficient solution, as shown in Figure 13. The main advantage is that because of the higher density of the gas it would be possible to carry out the compression in a single stage. Furthermore, owing to the higher outlet temperatures, higher grade heat would be available. A suitable point might be before the first stage of shift, when much of the heat has been removed in a raw gas boiler. After cooling to around 150°C, the gas at this point

will consist of $H_2$, CO, CO plus some steam. The main technical problem, requiring materials type R&D, would be the relatively high inlet and outlet compressor temperatures, leading to possible difficulties with the compressor impeller, shaft seals and bearings.
The heat generated by compression could be used for steam raising, although the temperatures should be high enough to promote the shift reaction. Figure 14 shows a possible arrangement in which the raw gas, after leaving one or more raw gas boilers, in which the inlet temperature is brought down to about 150°C, enters the compressor. After leaving the compressor, the raw gas now significantly hotter, passes through a cooler, then a boiler, before being reheated in the cooler. As the raw gas at this point is fairly dry, steam injected before the mixture enters the shift reactor. Process flow based R&D is needed to decide on how best to configure this concept.

### 5.3.2 Use of carbon dioxide for coal transport to the gasifier

A major problem with many types of gasifier is that they utilise nitrogen to transport coal to the gasifier or to remove air and raw gas from lock hoppers. This can add significantly to the amount of nitrogen in the final gas. The only practical means of eliminating this is by PSA, which will reduce the hydrogen output from the plant.

It is proposed that carbon dioxide be substituted for nitrogen for this duty, the $CO_2$ being abstracted from the captured stream of this gas. In some respects carbon dioxide should be better than nitrogen. The higher density of this gas should make coal transport easier, and, as $CO_2$ has a lemonade-like smell, if leakage occurs it will give more of a warning than with nitrogen. There are certain disadvantages that need to be recognised. The oxygen consumption of the gasifier is likely to rise. This is partly because of the higher specific heat of $CO_2$ compared to nitrogen. More importantly some of the $CO_2$ will react with coal to give carbon monoxide, which is an endothermic reaction. The presence of a somewhat greater amount of CO will require a bigger shift converter, altering the heat balances in the system. Hence, as with other proposals in this report, a process analysis study is called for.

### 5.3.3 Use of high grade heat

One of the current shortcomings of entrained bed IGCC systems is that the steam temperatures and pressures, which can be produced from utilisation of waste heat in the gasifier, are lower than desired. Ideally these should be compatible with the steam conditions in the HRSG section of the plant. The temperature and pressure limits are basically imposed by the inability of heat exchanger materials to operate at temperature of much over 400°C because of high temperature attack. Hence, efforts are being made to develop more resistant alloys.

The issue with a HYPOGEN plant is whether such developments in heat exchanger capability will improve the efficiency of the plant when it is producing hydrogen. The estimates given in Section 4.5, based on current and projected plants, seemed to suggest that there will be sufficient waste heat in the gasifier to generate power for the HYPOGEN plant ancillaries. However, there are some indications that with some processes, the mass of steam which is produced is not sufficient, or not at a sufficiently high temperature and pressure, for this purpose. When this is a problem it would be necessary to burn some hydrogen to raise more steam or increase the degree of superheat. Clearly, where there are deficiencies in steam conditions, the ability to produce more steam or better quality steam would enable more hydrogen to be produced. This increased quantity of hydrogen, since it is the fuel used to produce electricity would increase the efficiency of power generation too.

Where the gasification process was already able to produce sufficient power for ancillaries, the generation of higher grade steam would allow lower grade heat to be used for other purposes. A possible application would be to preheat reactants before they entered the gasifier. This would be extremely valuable in the case of the slurry based gasifiers, as the lower efficiency of these is partly caused by the heat needed to evaporate the water in the slurry. It results in greater oxygen demand and more $CO_2$ being produced during gasification process, so that the cold gas efficiency suffers.

A process analysis study is needed to evaluate the benefits which would result from being able to produce steam at higher temperatures and the resultant ability to utilise waste heat for preheating a water based slurry. It would appear, however, that the benefits of slurry preheating will increase as gasifier and slurry pressures increase. This is because the increase in pressure suppresses boiling of the slurry so that it is possible to heat it to a higher temperature. These process studies would give a target for any materials development work that would be needed to permit heat exchanger temperatures to be raised.

### 5.3.4 Selective catalytic oxidation of carbon monoxide

Even after shift conversion the levels of carbon monoxide in the gas will probably be around the 1% level, which would be too high for fuel cells of the PEM type. If it were desirable to eliminate this gas the standard approach would be by PSA. This would lead to losses of hydrogen output. It may be possible to eliminate the PSA equipment or, at least, reduce the hydrogen losses by using a selective oxidation catalyst to cut down CO levels to the 50 ppm range. In this process a small amount of oxygen would be introduced which reacts with the CO over the catalyst. Because of the low levels of CO it may be necessary to preheat the reactants to around 150°C. Work is needed to assess the cost and life of this catalyst under typical HYPOGEN conditions, and whether the catalyst volume needed will make this approach acceptable.

### 5.3.5 Compact heat exchangers

There should be some potential for cost reduction and possible improvements in efficiency through the use of compact heat exchangers. In their more advanced forms equipment of this type can dispense with pressure vessel containment. Exchangers of this type are made out of diffusion-bonded plates into which millimetre sized heat exchange channels have been etched. Stresses within the exchanger are very low so it becomes possible to use the outer surface of the exchanger as the pressure vessel. Very significant reductions in size and throughput result, greatly reducing transport and on-site erection costs. A possible concern would be the manifolds into the exchangers as these are of a rectangular form, so that high stresses are induced, and R&D would be needed in this area.

A related development is to coat the heat exchanger channels with a catalyst where the aim is to keep this at the optimum temperature, by either taking away heat, if the reaction is exothermic, and by adding heat if it is endothermic. A potential application would be in a shift reaction where the increase in temperature reduces the amount of hydrogen that can be produced. An exchanger of the type outlined above, would incorporate a shift catalyst on the gas side of the exchanger, with boiler water on the other. As the heat transfer characteristics of such exchangers are very good, because of the high surface area to volume ratio, hydrogen production would be significantly enhanced. More advanced forms could possibly be substituted for the combined steam reforming/autothermic reforming systems which currently need a pressure vessel. R&D needs to progress the development of these concepts and test them at the larger scale,

### 5.3.6 Optimisation of size of gasification unit and associated equipment

The gasifier and associated plant such as ASU, acid gas removal, $CO_2$ compression, etc, represent the major capital expenditures to a HYPOGEN. In contrast, the combined cycle section of a plant, which is generating power for export represents relatively minor fraction of the construction costs (i.e. somewhere in the range 30-40%). As the hydrogen economy develops HYPOGEN plants will be connected to a large pipeline network which, as described, can be used to store hydrogen at night. However some of this hydrogen could be then taken back into the CCGT section of the plant to boost power during peak periods.

In effect, the gasification section of the plant would be undersized in terms of the rated output of the plant, which would have an extremely beneficial affect on capital costs, and would increase the competitiveness of the plant compared to conventional power plants. None of these have the capability to build up a store of easily useable energy at times of low demand. In a sense, this design of HYPOGEN plant has analogies to hydroelectric pumped storage.

There will be some additional expenditure, but these should be small. The most obvious is that of the pipeline. However this will have to be constructed anyway to deliver hydrogen to long distance consumers. Clearly a techno-economic study is needed. To keep things realistic and maintain flexibility of output one would estimate that the CCGT should be built with a capacity of about 20% more than the nominal output of the gasification system when working in base load mode.

## 6. Conclusions

This report has analysed current methods of producing hydrogen and electricity based on proven natural gas steam reforming and coal gasification processes. The main intention was to focus on what changes would be needed if off-the-shelf processes were to be used in a HYPOGEN plant that could vary its energy out put from 100% hydrogen to 100% electricity. This ability to vary the ratio of hydrogen to electricity should help maximise plant profitability, as electricity would be produced when the electricity price is high. At other times hydrogen would be piped long distances, via the transmission system, which would also act as short term storage for hydrogen. The preliminary conclusions are that this type of flexibility will be practical, and because it is combined with the ability of HYPOGEN plants to capture $CO_2$ for subsequent storage, these types of plant will be highly suited for the production of power in an energy economy in which electricity from wind and solar sources will play a major part.

It would appear that the electrical efficiency of a HYPOGEN plant could be lower than that of a conventional IGCC system, even when discounting the energy losses which result from capturing $CO_2$. This results from the difference in calorific value between fuel gas from conventional IGCCs, which has a high content of carbon monoxide, and the fuel gas from a HYPOGEN plant which would be almost pure hydrogen. If HYPOGEN plants do suffer from this lower electrical efficiency, this would, other things being equal, tend to undermine the profitability of HYPOGEN plants. However, an electricity-only IGCC will need to restrict its power output when electricity demand falls and this will become more of a problem in the future. This is not the case with the flexible HYPOGEN concept, which would be able to maintain plant output and maximise its revenue by selling its energy in to the most profitable market, be it for hydrogen or for electricity.

Looking further to the future when the hydrogen pipeline system is fully developed, it should then be practical for the operators of a HYPOGEN plant to utilise some of the hydrogen in the transmission pipeline to enhance electrical power output, at peak times. To what degree a HYPOGEN plant should, try to make use of “its own hydrogen” is an issue that requires investigation. It is clear that the relative size of the gasification section of the plant would decrease compared to the combined cycle sections of the plant , as the latter would be increased in size to generate more power than the fuel gas from the gasifier would provide.

The report has also reviewed the main factors that will need to be considered in the design of HYPOGEN. The main issues have been those of hydrogen purity and flexibility varying the ratio of hydrogen to electricity. The question of hydrogen purity is likely to have very strong implications for plant costs, electrical efficiency and hydrogen output, and some tentative views, in the context of existing ISO specifications, have been put forward. Clearly any final decision about this will need more detailed evaluation, but the implications for plants which manufacture hydrogen from fossil fuels by a gasification or steam reforming route need careful consideration.

In terms of flexibility, it is desirable, when there is no demand for electricity from external consumers, that the HYPOGEN plant produces just enough power to run the oxygen plant, acid gas removal system and the carbon dioxide capture and compression units. Although more detailed analysis is needed, this appears to be practical.

The decision about hydrogen purity and plant flexibility does impact on the decision to whether or not to employ PSA for final purification of the hydrogen stream. The advantage of conventional PSA is that it produces hydrogen of an extremely high quality. The main disadvantage is that there is a loss of hydrogen of about 5-15% in this purification step. The loss appears as a tail gas at atmospheric pressure, and it could be difficult to find a suitable use for it on a HYPOGEN plant. The tail gas might be used for power production but this could mean the HYPOGEN plant having to find a market for electricity at all times. This goes against the ideal of a totally flexible plant. The tail gas problem could be almost entirely eliminated by using nitrogen as a purge. This would result in some contamination of the hydrogen by nitrogen, which again would need to be considered in terms of hydrogen purity.

The other general design issue for HYPOGEN plants is that for long distance transmission of hydrogen outlet pressure should be at least as high as current natural gas pipeline pressures. These operate at 70-100 bar. No steam reforming plant operates at anywhere near those pressures, and of the coal gasifiers, the only commercial processes able to run at high pressures are water-coal based slurry fed, designs. This suggests the need for development work with compressors, so as to raise the hydrogen pressure for delivery to the transmission system.

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# Appendix 1

## Hydrogen and Electricity Outputs from HYPOGEN Plants

The hydrogen and electricity outputs given below are based on what would be state of the art, HYPOGEN plant concepts, based on coal gasification and steam reforming. To give a fair comparison between coal gasification and steam reforming, the results are based on an equivalent coal input of 100 tonnes of coal an hour. This is equal an energy rate input of 713 MW. The natural gas fuel, equivalent to this, is 66700 $m^3$/h.

Because the efficiencies of the two processes are different, with coal gasification being less efficient than steam reforming, the amounts of hydrogen that are produced are quite different. However as only a conventional steam reformer was modelled the capture rate of $CO_2$ was significantly less than that of a coal gasification based process. The calculations were based on the use of a normal reformer, fuelled using tail gas only. The tail gas, however, contained significant amounts of methane, which led to a $CO_2$ capture rate of only 84%. This is compensated for by the higher efficiency of the steam reforming and the lower carbon content of natural gas.

The electrical output from the plant has been calculated on the basis that the CCGT plant which uses the hydrogen output has a fuel-to-electricity efficiency of 60%. Hence the efficiency of the plant is reduced by a factor of 0.6 compared to when hydrogen is being produced. Hydrogen purity in both cases was 99.9%

By today’s standards a plant electrical output of 230 MW from the coal based plant would be regarded as being small. This would produce enough power for a city of around a quarter of a million people, at times of maximum power demand. In terms of hydrogen output, basing this on typical consumptions in Northern Europe, one can make a very rough estimate that the hydrogen output from such a plant would be enough to supply about half the population of such a city. Much would depend on the ability to store hydrogen locally.

## Coal Gasification

**Input Fuel  -** 100 tonnes/hour (713MW equivalent)

**Consumption of Water for Gasifier and Shift Processes** –  83.4 tonnes/hour

**Oxygen Consumption** – 89.2 tones /hour  (99.5 % pure)

**Hydrogen Production –** 129400 $m^3$/hour (387MW equivalent)

**Hydrogen Production Efficiency –** 54.2%

**Electrical Output and Efficiency –** 232 MWe at 32.5%

**$CO_2$ Capture Rate and Efficiency -** 227.2  tonnes/hour at 96.4 %

## Steam Reforming

**Input Fuel  -** 66700 $m^3$/hour (713MW equivalent)

**Consumption of Water for Reformer and Shift Processes** –  96.0 tonnes/hour

**Oxygen Consumption** – None

**Hydrogen Production –** 172637 $m^3$/hour hydrogen (517 MW)

**Hydrogen Production Efficiency –** 72.5%

**Electrical Output and Efficiency  –** 310.2 MWe at 43.5%

**$CO_2$ Capture and Efficiency -**113.8 tonnes/hour at 83.7 %

# Appendix 2

## Integration of Combined Cycle Gas Turbine, Steam Turbine and HRSG Plants with Gasifier Systems

### *1. Gas Turbine Considerations*

Natural gas fired CCGTs have been deployed since the early seventies, when efficiencies were in the thirty percent range, but plant construction times were much more rapid than that of steam plant. CCGTs have now reached the sixty percent efficiency mark on an LHV basis, well ahead of any other commercial energy conversion system. One authority recently expressed the view, unofficially, that 74% was the probable limit, given the potential for advances with gas and steam turbines [42]. Capital and operating costs for CCGTs are still lower than of any other means of producing power from fossil fuel.

The gas turbine in a CCGT produces about two thirds of the power of the plant. The pressure ratio in the gas turbine is around 20/1 for most modern designs, which would be compatible with the operating pressures of many types of gasifier. These relatively modest pressure ratios maximise the power output from the gas turbine, and result in a high exit temperature from the gas turbine and a reduction in the excess air in the flue gas. Both high exit temperature and low excess air contribute to the steam raising ability of the HRSG, thereby enhancing steam turbine output. Future designs of gas turbines, if they are to hit the efficiency targets mentioned above, will probably need to be of a much more advanced design [1]. Pressure ratios will be in the 30-45/1 range implying the need for gasifiers that can deliver fuel gas at much higher pressures than current designs.

In the most modern CCGT plants some of the steam from the HRSG is used to cool gas turbine components. The GE Frame H takes steam from the outlet of the HP steam turbine, where the temperature has probably fallen to about 350ºC, to cool the inlet gas turbine blades. This steam is returned to the HRSG, to be mixed with the outlet reheater steam. Westinghouse uses a slightly less sophisticated system whereby the steam is used to cool the transition duct, which leads the hot gases from the burner into the turbine itself.

The need to provide very high quality steam for this duty, over a restricted range of temperatures and pressures, may have some implications for the amount level of integration between the steam systems of the gasifiers and those which are part of the CCGT. An interruption in the steam flow or carryover of droplets of moisture or contaminants could wreck the gas turbine. Since these problems are more likely to occur during start up, doubt has been thrown on the viability of using steam cooled gas turbines in any type of CCGT that will have to be used in for plant cycling. In addition steam is not available until after the gas turbine has started up. This should not be a problem with the flexible plant concept, as good quality steam is being generated all the time.

### *2. Integration of HRSG with Gasifier Steam System*

Even the simplest form of HRSG on a natural gas fired CCGT plant is quite complex. It consists of several different sets of economisers, evaporators and superheaters, all distributed along the flue gas channel. This has significant implications for the integration of its steam system with that of the boilers, which make up a gasifier heat recovery system [2, 3].

In the HRSG, the flue gas enters the heat exchange system at a relatively modest temperature of between 580-650ºC, depending on the characteristics of the gas turbine. Steam turbines are at their most efficient with highly superheated, high pressure steam, that is, steam whose pressure and temperature exceeds 100 bar and 520°C. Unfortunately only a small proportion of the heat in the flue gases can be used for this purpose. Once the flue gas falls much below 400°C, it is better to use the heat to generate steam at pressures around 5 bar and with superheat temperatures of 250°C. Hence most HRSGs produce steam at two pressures, in contrast to a coal fired steam plant which produces all the steam at one very high pressure, although steam is reheated at lower pressures.

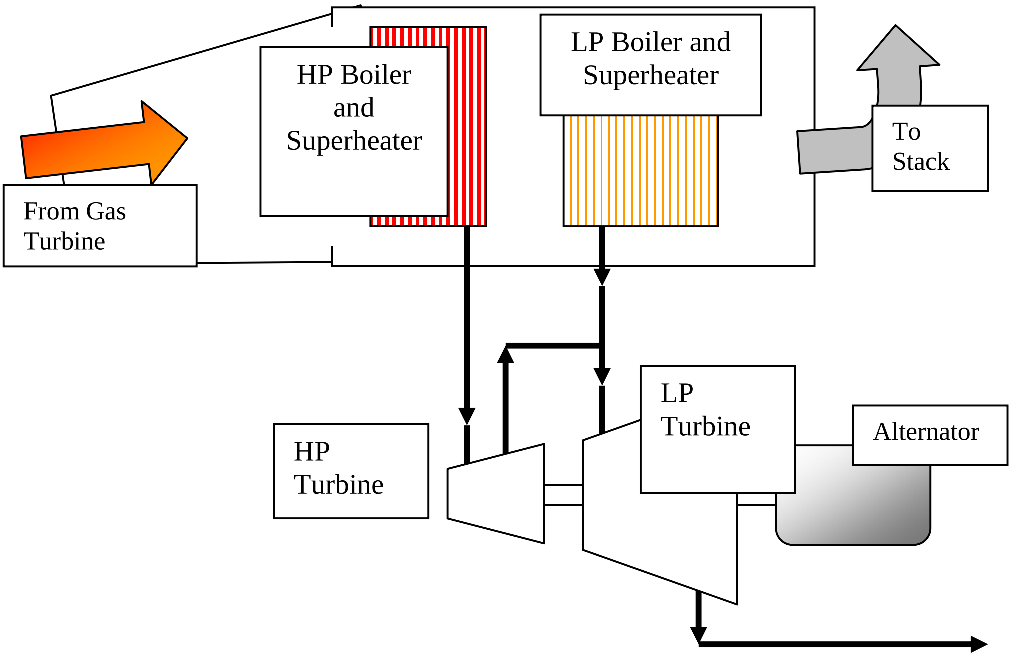


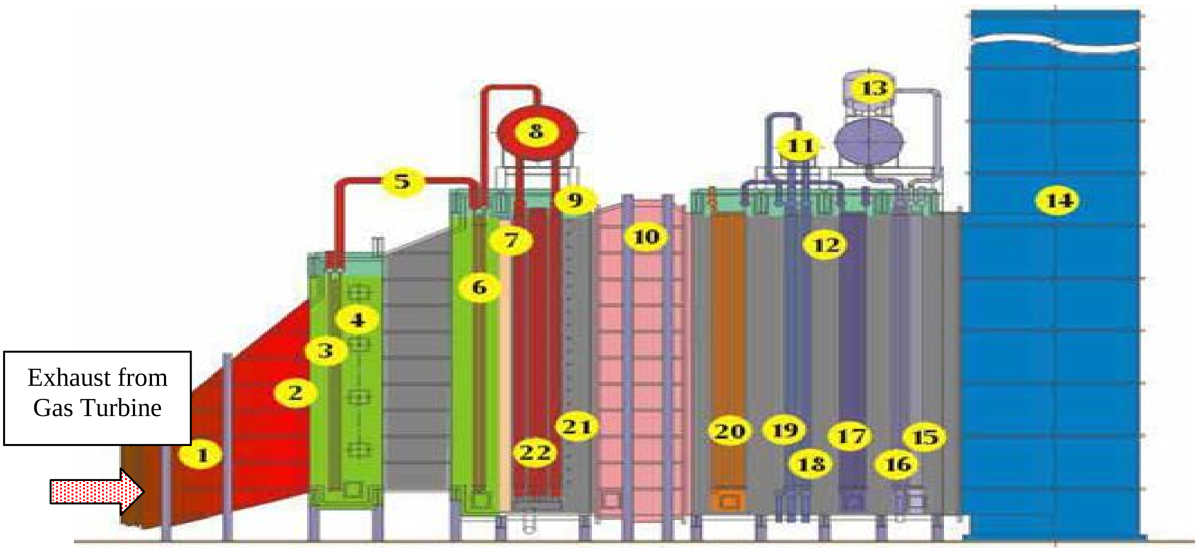
**Figure 1: Schematic of HP and LP steam production and flows in a Heat Recovery Boiler of CCGT Plant**

Figure 1 shows a schematic of a typical HRSG in which the steam is produced and superheated at two pressures, high and low. In consequence there are two sets of steam turbines, one taking steam at high pressure, the other steam at low pressure. Note that after leaving the high pressure turbine, the exhaust steam from this joins the steam coming from the low pressure boiler and superheater. The expansion through the high pressure turbine needs to give an outlet steam temperature and pressure which match almost exactly that what comes from the low pressure superheater, otherwise energy will be wasted.

In a conventional, electricity only, IGCC plant, where some of the steam for these two sets of steam turbines is raised from the waste heat from the gasification process, it is necessary to ensure that the pressure and temperature of the steam that is produced will be compatible with that being generated and used in the CCGT plant. But in a HYPOGEN plant where the syngas is put through a series of shift converters, additional steam is produced at two or more different temperatures and pressures, in addition to the steam produced as a result of gasification. The use of this steam in the CCGT requires careful consideration to ensure that there is a good match with the steam being generated in the HRSG.

Turning back to a simple HRSG, in an ideal system, the temperature of the water and steam should rise uniformly through the HRSG as it passes from the cold water inlet to the production of superheated steam at the outlet. This would ensure that the flue gas gave up its heat gradually and uniformly as it passed from the outlet of the gas turbine to the entrance of the stack. Unfortunately, at the points in the HRSG, where the water turns into steam, there is no temperature change, even though, because of latent heat effects, a great deal of heat is taken out of the flue gas. Furthermore, it should be noted, that in those sections of the HRSG, where the water is being evaporated, the flue gas temperature cannot drop below the temperature which corresponds to the boiling point. For example, as the flue gas passes through the high pressure evaporating section, which might be working at 100 bar pressure, the flue gas cannot drop below 311°C, as this is the boiling point of the water at that pressure. Similarly in the low pressure evaporator the flue gas cannot drop below 152°C. To overcome these problems with discontinuities in water and steam temperatures, the economisers, evaporators and superheaters have to be carefully located in the flue gas duct. This would be true of any type of the HRSG on any type of combined cycle, including those on HYPOGEN plants.

The steam turbines in the most modern CCGTs incorporate a reheat steam turbine and a reheat heat exchanger in the HRSG. The latter will work at the same temperature as the high pressure superheater, although the pressure would be around 30 bar. The addition of this unit further complicates the location of the various heat exchangers in the HRSG, which need to be carefully distributed along the HRSG flue gas duct as shown in Fig 2. The need to get the heat transfer right, and to reduce the costs of HRSG construction, has led, on occasion, to some serious problems in starting up and shutting down of HRSGs.



1 Inlet Duct
2 Distribution grid
3 HP Superheater 1
4 Burner
5 Split Superheater
6 HP Superheater 2
7 CO Catalyst
8 HP Steam Drum
9 Top Supports
10 SCR Catalyst
11 LP Steam Drum
12 HRSG Casing
13 Deaerator
14 Stack
15 Preheater
16 DA Evaporator
17 HP/IP Economizer
18 IP Evaporator
19 IP Superheater
20 HP Economizer
21 Ammonia Injection Grid
22 HP Evaporator

**Figure 2: Schematic of horizontal HRSG boiler and superheater showing individual components (Courtesy Nooter Eriksen)**

Similar considerations also complicate the design and location of the other heat exchangers in the **gasifier heat train.** High temperature corrosion is, however, a major factor, which prevents a high degree of superheat being given to any steam that is produced. Ideally to make best use of such steam would call for a superheat of over 500°C, implying metal temperatures of around 550°C. This is somewhat above the safe limits of available alloys because of the risk of sulphidation and other forms of high temperature corrosion from the syngas [4, 5, 6, and 7].

The consequence is that a design study for a fixed ratio HYPOGEN plant, which will imply a high degree of integration, can be a very lengthy process because of the need to ensure compatibility between the temperatures and pressures in the gasifier and CCGT steam systems. Here it should be noted that whereas the effects of non-optimised heat recovery in the HRSG section of the CCGT will lead to a slight reduction of efficiency, the same is not necessarily true of steam generation in the gasifier process chain. Here as well as trying to produce steam for power production in the best possible way, it is essential to cool the gases down, firstly to permit the gases to be sent to the acid gas removal system. Then, when hydrogen is being transmitted via pipelines, it must be cooled to near ambient temperature. In the case of a flexible ratio HYPOGEN plant since the CCGT and the gasifier will be quite different sets of equipment, in principle there will be little need for integration and hence the design of the steam raising equipment for each of these can proceed independently. This should cut design, construction and commissioning time.

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## Abstract

The report summarises the issues in adopting IGCC and Steam Reforming Plants for HYPOGEN schemes, where hydrogen and electricity are produced from coal or natural gas, with the carbon dioxide which is also formed being captured for subsequent storage. An important consideration, because of the day to night variation in electrical power demand, is the need to be able to vary the ratio of hydrogen to electricity. Various gasification systems are reviewed and the conclusion is that oxygen blown systems, which can produce hydrogen at high pressure, would provide a basis for future plant studies.

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