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ENGINEERING AND ECONOMIC ANALYSES OF A COAL-FUELED SOLID OXIDE FUEL CELL HYBRID POWER PLANT

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ABSTRACT

An advanced coal based power plant system that has an electrical efficiency of 60% on an HHV basis is defined. The solid oxide fuel cell (SOFC) hybrid has been shown to be an essential requirement in order to achieve such a high efficiency. The coal is gasified utilizing a high pressure air-blown advanced transport reactor (ATR). A thermo-economic analysis of this integrated gasification fuel cell (IGFC) plant is performed by comparing it to an integrated gasification combined cycle (IGCC) plant that utilizes a gas turbine combined cycle for power generation. Results of this thermo-economic analysis indicate that the required "break even" cost of the SOFC system is \$400/kW on an installed cost basis such that the cost of electricity of IGFC plant is the same as that of the IGCC plant. Coproduction of H_2 and capture of carbon emissions may be incorporated in the design without causing a major thermal penalty on the system performance when high temperature separation membranes are employed. An O_2-blown gasifier is required for such applications. The technology development needs are addressed.

INTRODUCTION

Under the sponsorship of the U.S. Department of Energy (DOE) / National Energy Technology Laboratory, a multi-disciplinary team led by the Advanced Power and Energy Program (APEP) of the University of California at Irvine is defining the system engineering issues associated with the integration of key components and subsystems into power plant systems that meet performance and emission goals of the Vision 21 program. The overall objectives of this Vision 21 program are summarized as:

- produce electricity and transportation fuels at competitive costs
- minimize environmental impacts associated with fossil fuel usage, and
- attain high efficiency.

The efficiency targets are 75 percent (LHV) for natural gas fueled plants and 60 percent (HHV) for coal fueled plants producing electricity only, that is, plants without CO_2 capture nor coproduction of any transportation fuels or H_2 [Der, 1999].

Earlier tasks of the program have narrowed down the myriad of fuel processing, power generation, and emission control technologies to selected scenarios that identify those combinations having the potential to achieve the Vision 21 program goals. These analyses have been extended to consider coal gasification processes combined with the advanced power cycles previously identified. The technology levels considered are based on projected technical and manufacturing advances being made in industry and on advances identified in current and future government supported research. Examples of systems included in these advanced cycles are solid oxide fuel cells, advanced cycle gas turbines, and membrane separation of gases.

Specifically, the objective of this program being conducted by the team led by the APEP is to identify gas and coal based system configurations that meet the above Vision 21 goals with emphasis on attaining the highest performance. The results of this investigation will serve as a guide for the DOE in identifying the research areas and technologies that warrant further support.

The approach taken in this investigation has been reported previously [Rao, et al, 2002]. Briefly, it consists of first identifying the sub-systems that make up a complete power plant followed by a screening analysis in order to narrow down the number of possible configurations for more detailed analysis. It was shown that without fuel cells, gas turbine based cycles alone even with very high firing temperatures cannot meet the efficiency goals of the program. These included inter-cooled, reheat, and recuperated cycles (e.g., Ericsson), combined cycles including those incorporating bottoming cycles such as the Kalina cycle, and the Humid Air Turbine (HAT) cycle [Rao, 1989]. Thus, gas turbines integrated with fuel cells (hybrids) are required for these Vision 21 power plants.

The detailed analysis phase of this study consists of conducting a more in-depth analysis of cases that have evolved from the screening phase to develop the performance estimates, the ultimate goal being to provide a definition for the fuel cell and the gas turbine design parameters along with the interface conditions between the fuel cell, the gas turbine and the balance of plant. The selected coal based cases are listed below:

- IGFC Power Only Case - Generate electric power utilizing an air-blown ATR and SOFC hybrid
- IGFC Near "Zero Emission" Case - Generate electric power utilizing an O_2-blown ATR and SOFC hybrid with CO_2 capture
- IGFC "Advanced FutureGen" Case - Generate electric power utilizing O_2-blown ATR and SOFC hybrid with H_2 coproduction and CO_2 capture.

The plant performances were developed utilizing the Advanced Power Systems Analysis Tool (APSAT) developed at the University of California, Irvine. It includes a model for a tubular SOFC based on first principles as well as models for the other subsystems in the plant such as the gas and steam turbines, membranes, various reactors, humidifiers and heat exchangers. A detailed description of this analysis tool is provided in a previous publications [Rao and Samuelsen, 2002].

The thermo-economic analysis to develop a target cost for the SOFC system is performed by first establishing the levelized cost of electricity of an IGCC plant which also consists of the advanced coal gasification system but utilizing an advanced gas turbine based combined cycle instead of an SOFC hybrid. This IGCC case is derived from work previously published in a DOE report [Shelton and Lyons, 2000]. The gas turbine consists of the Siemens-Westinghouse 501G machine. Methodology described in EPRI's Technical Assessment Guide [Applegren.and Vejtasa, 1982] is utilized in developing the levelized cost of electricity (COE). Table 1 summarizes the basis for the economic analysis. The coal price and escalation rates are based on projections made by the DOE's Energy Information Agency for the period beyond year 2020 when such advanced plants may be expected to be commercialized. The coal price escalation rate is expected to be low due to the advances taking place in the mining techniques, the mining costs being a significant component of coal price.

Table 1: Basis for Economic Analysis

Coal Price (Illinois No. 6)	\$1.07/GJ (\$1.13/MMBtu)
Project Book and Tax Life	20 Years
Escalation Rates	
Coal Price	0.42%/y
Total Plant Cost	3%/y
General	3%/y
Property Taxes	0.1% of Escalated Plant Cost
Insurance	0.7% of Escalated Plant Cost
Federal + State Income Tax	38%
Project Financing	
Common Equity	65%
Debt	35%
Maximum Annual Capacity Factor	85%

An estimate of the installed cost of the SOFC system is established in a manner such that the levelized COE of the IGFC plant (producing power only) is identical to that of the IGCC case. The cost of the fuel cell system thus estimated then provides the fuel cell developers with a basis for setting the goals for their system design and costs.

DESIGN BASIS

The design ambient conditions consist of utilizing ISO ambient conditions of 15ºC (59ºF) dry bulb temperature, 60% relative humidity and sea level. Mechanical draft cooling towers are utilized for plant heat rejection with a 3.9ºC (7ºF) approach to the wet bulb temperature. A 11.1ºC (20ºF) temperature rise is assumed for the cooling water while a 5.6ºC (10ºF) approach temperature is utilized in the steam turbine surface condenser. The design basis for the gas turbine and the fuel cells utilized in this study are summarized in Tables 2 and 3. The very high firing temperature of 1700ºC was utilized in the study to determine if the Vision 21 efficiency goal could be met with gas turbines alone, i.e., without fuel cells. In natural gas applications, the resulting efficiency of a steam-cooled gas turbine based combined cycle (without the SOFC) was in the neighborhood of 65% (LHV) [Rao, et. al., 2002], significantly lower than the 75% (LHV) goal. Note however, that in the hybrid applications, the gas turbine firing temperature was at the modest value of 920ºC.

Table 2: Gas Turbine Design Basis

Firing Temperature	≤ 1700ºC
LP Compressor Isentropic Efficiency	90%
HP Compressor Isentropic Efficiency	88%
LP Turbine Isentropic Efficiency	94%
HP Turbine Isentropic Efficiency	92%
Turbine Materials	Ceramics and Thermal Barrier Coatings
Generator Efficiency	98.6%

Table 3: Fuel Cell Design Basis

Fuel Utilization	85%
Individual Cell Voltage	≤ 0.75V
Effective Air to Fuel	≥ 2 x Stoichiometric Amount for Complete Fuel Utilization
Invertor Efficiency	97%
Cell Geometry	Tubular with Central Injection Air Preheat Tube
Air Preheat	Against Vitiated Air and within Central Injection Tube
Fuel Reforming	Internal within Stack

The coal utilized in this study consists of the bituminous Illinois No. 6 coal while limestone is utilized as the bed material for the capture of sulfur in the ATR [Leonard, et. al., 2001].

IGFC POWER ONLY CASE

Plant Description

The overall process scheme is depicted in Figure 1. The plant consists of an ATR for converting the coal into syngas while the power block consists of a SOFC based hybrid combined cycle. An ATR has features of a circulating fluidized bed gasifier and is being developed under sponsorship of the DOE at Wilsonville, Alabama [Leonard, R., et.al., 2001; Swanson, M. and Hajicek, D., 2002]. A smaller scale ATR is also operated by the Energy and Environmental Research Center at the University of North Dakota (UNDEERC). The ATR has the potential for achieving the overall plant efficiency goals of Vision 21, the main reasons being that (1) the raw syngas leaves the gasifier at a temperature of approximately 1050ºC which is significantly lower than that for entrained bed gasifiers where the temperature is typically in excess of 1300ºC (thus a lower fraction of the coal bound energy is degraded to thermal energy within the gasifier), and (2) a correspondingly lower oxidant demand. Furthermore, the lower raw syngas temperature requires less cool-down, making the syngas coolers less expensive.

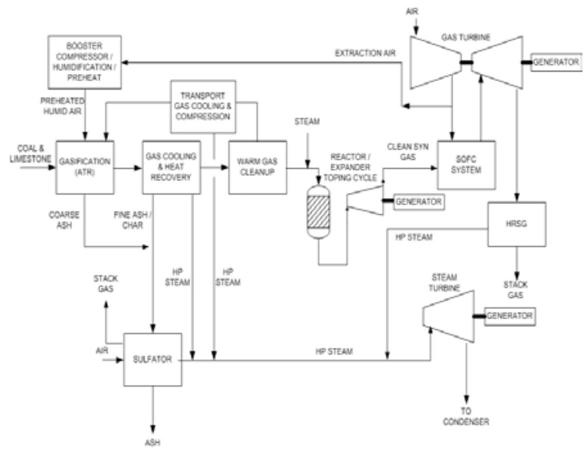

Figure 1: Block Flow Sketch – IGFC Power Only Plant

Ground Coal along with ground limestone (both < 500 microns particle size) for in-bed sulfur capture (about 85% of the sulfur is expected to be captured along with over 90% of the chlorine) is added to the upper stage of the mixing zone of the gasifier. The gas exits the top of the gasifier riser and goes to a primary cyclone that is connected to a standpipe that receives the unburned char and ash/bed material for recirculation back to the mixing zone. The overall carbon conversion for this air blown ATR is assumed to be 95%.

The coarse ash withdrawn from the ATR has very little carbon in it and has the consistency/appearance of beach sand. It can be utilized as bed material for a fluidized bed unit. The fine ash separated from the syngas has typically 30% carbon. This fine ash or char which and is not in a vitrified state also contains more than 95% of the CaS formed within the gasifier. The fine ash along with the coarse ash are treated in a sulfator where the CaS is oxidized to $CaSO_4$, the carbon is combusted and the heat is recovered by generating steam.

The syngas leaving the gasifier at 1050ºC is cooled to 400ºC by generating superheating steam in a convective cooler. It then goes to a barrier filter where over 99.99% of the remaining particulates are removed. Next the syngas is fed to a chloride guard bed consisting of nahcolite, which also removes any other remaining halides. From the chloride guard bed which is followed by another barrier filter, the fuel gas goes to a zinc titinate bed for final sulfur removal and then to a final particulate filter.

A fraction of the syngas is utilized as transport gas for feeding the solids to the ATR. The required amount of gas is first cooled in a series of heat exchangers while providing heat for steam generation and for the gasifier air humidifier. The syngas is next further cooled against cooling water and then compressed to the required pressure. A closed loop N_2 system provides the gas required for pressurization of the lock hoppers that feed the coal and limestone to the gasifier, while the required make-up N_2 is supplied by on-site stored N_2.

A fraction of the gas turbine compressor discharge air is sent to an aftercooler, boosted in pressure, recuperated, humidified in a counter-current packed column utilizing process condensate supplemented with treated make-up water [Rao, 2003] and sent to the mixing zone of the ATR. The humidification operation generates the entire steam required for the ATR while reducing the amount of waste-water to be treated. The gas turbine also provides the small quantity of pressurized air required by the warm gas cleanup unit.

Emission of mercury from coal-based power plants has gained much attention in the recent past. Warm gas mercury removal processes are being developed and one such process is that being developed by ADA technologies that operates around 400ºC [Butz et. al., 2003]. The syngas is passed through a fixed bed reactor containing an Amended Silicates™ sorbent where the mercury is chemisorbed. Next, the syngas is combined with steam and fed to a fixed bed reactor containing a methanation catalyst followed by a turbo-expander [Rao, 1991]. The methanation / shift reactions that occur within the reactor serve in (1) producing additional methane (in addition to that generated within the ATR) and (2) raising the temperature of the syngas (from 384ºC to 684ºC). The increased methane content of the syngas assists in providing a heat sink (by the endothermic reforming reactions) for the heat generated within the SOFC (which reduces the amount of excess air required in the SOFC and thus increase the overall plant efficiency) while the increased temperature of the syngas increases the power developed by the turbo-expander which expands the syngas from a pressure of 2,310 kPa to 1,880 kPa. It also reduces the amount of heat exchange required within the SOFC system to heat up the anode inlet gas since the temperature of the syngas (leaving the expander) is increased. Steam added to the syngas upstream of the methanation reactor avoids carbon deposition within the reactor as well as within the reformer located in the SOFC stack.

A chloride guard bed consisting of Na on alumina followed by a sulfur guard bed consisting of alternating layers of COS hydrolysis catalyst such as a Co Mo or a Ni MO catalyst and ZnO for the H_2S capture may be included upstream of the methanator as a final cleanup step to remove any trace amounts of the chlorides and sulfur compounds to the level required by the methanation catalyst (and the reforming catalyst within the SOFC system) of 0.1 ppmV for each of these impurities.

The methanated / expanded syngas after being preheated and reformed within the SOFC module is fed to the anode side of the cells. Compressed air supplied by the gas turbine, at approximately 1,880 kPa, is heated against the cathode exhaust gas within the SOFC module and then supplied to the central injection tubes of the tubular fuel cells for further preheat prior to entering the cathode side of the cells. The combusted exhaust gas from the SOFC module is expanded in the gas turbine while the heat contained in the gas turbine exhaust is recovered in a heat recovery stream generator (HRSG).

The bottoming cycle in the power block consists of the gas turbine followed by a non-reheat steam cycle. The firing temperature of the gas turbine was only 920ºC. It is advantageous from a thermal efficiency standpoint to maximize the conversion of the fuel bound energy to power in the topping fuel cell while minimizing the energy entering the bottoming combined cycle. High pressure (HP) superheated steam at 10,880 kPa and 538ºC is supplied to the steam turbine while intermediate pressure (IP) steam at 2,600 kPa is extracted from the steam turbine for addition to the syngas upstream of the methanator for carbon control while low pressure (LP) steam at 470 kPa is extracted for the coal drying operation.

Plant Performance

Table 4 provides the plant performance summary. The plant consumes 2241 MT/D of the bituminous coal and produces 423 MW of electric power while achieving the Vision 21 overall plant net thermal efficiency goal of 60% (HHV). The calculated cell current density at a cell voltage of 0.75V is 161 mA/cm^2.

The overall thermal efficiency is determined to decrease only slightly when the fuel cell operating pressure is reduced by more than a third while incorporating the Reactor / Expander topping cycle within the plant design. The net efficiency is reduced to 58.9% (HHV) from 60% (HHV) when the syngas inlet pressure to the fuel cell module is reduced to 1,200 kPa from 1,880 kPa. Although Siemens Westinghouse (then Westinghouse) had successfully tested a tubular cell at a pressure of 1,520 kPa under a DOE contract (DE-FC21-91MC28055), the weak dependence of thermal efficiency on the fuel cell operating pressure should be welcomed by fuel cell developers since there are challenges associated with developing the required seals as well as the materials for fuel cells operating at very high pressures. The dynamic behavior of the hybrid during plant trips is also a concern at high fuel cell operating pressures. Reducing the fuel utilization from the design value of 85% to 80% also has a small effect on the thermal efficiency of the plant, reduces to 59.4%.

Table 4: Performance Summary - IGFC Power Only Case

Coal Feed Rate (as Received), MT / D MWt (HHV)	2241 703.6
Fuel Cell Power, MW	234.6
Gas Turbine Power, MW	109.8
Steam Turbine Power, MW	86.0
Methanated Syngas Turbo-Expander Power, MW	6.3
Total Gross Power Generated, MW	436.7
Internal Power Consumption, MW	13.9
Net Electric Power (at Generator Terminals), MW	422.8
Overall Thermal Efficiency, % HHV	60.1

IGCC POWER ONLY CASE

Plant Description

The gasifier again consists of the air-blown ATR fed with the Illinois No. 6 coal and warm gas cleanup system. The combined cycle utilizes the Siemens-Westinghouse 501G gas turbine. This turbine has four stages with directionally solidified blading and thermal barrier coatings, and advanced cooling technology (steam-cooled combustor and transition section). Sixteen combustors of the can-type are arranged in a circular array. The compressor pressure ratio is 19.2 and has an inlet air flow of 563.1 kg/s (1241 lb/s) at ISO conditions. Both the compressor and the turbine have advanced aero-engine technology with three-dimensional airfoil design in compressor and turbine. The first stage rotor inlet temperature is 1477ºC (2583ºF). The steam cycle-consists of a three pressure level reheat cycle with the steam turbine inlet conditions of 124 bar / 566ºC / 23.6 bar / 566ºC / 2.4 bar (1800 psia / 1050ºF / 342 psia / 1050ºF / 35 psia).

Plant Performance

The overall plant performance as published in the referenced DOE report [Shelton and Lyons, 2000] is updated for the carbon conversion of 95% and the gasifier operating temperature (i.e., syngas exit temperature) of 1050ºC (the referenced DOE study utilized a higher carbon conversion of 96.8% and a lower gasifier operating temperature with the syngas leaving the gasifier at 903ºC). The net power output is held constant while the coal feed rate to the plant is increased due to the increase in the overall heat rate. The costs are updated to 2nd Quarter 2004 utilizing an annual escalation rate of 2%, and a mercury capture step is added similar to the previous IGFC case. Adjustments are also made to the plant costs to account for the higher coal feed rate.

The plant produces 415.4 MW of net electric power at a thermal efficiency of 48.2% (HHV). The estimated total plant installed cost is $1161/kW resulting in a 10th year levelized cost of electricity of 39 Mills / kWh.

RESULTS

An estimated total installed cost for the IGFC plant of $1268/kW results in an overall cost of electricity same as that of the IGCC case of 39 Mills/kWh (10th year levelized cost), i.e., the higher efficiency of the IGFC case at 60.1% over the IGCC case at 48.2% justifies an 8% increase in the plant cost. The resulting SOFC system installed cost with engineering fee and all contingencies included is $400/kW. No economic credit is given to the IGFC plant for its lower CO_2 emission on a kW basis resulting from its lower heat rate. It should be noted that although the plant cost estimates as absolute values are approximate, the costs for the two plants are developed on a consistent basis with the major differences being in the power block. The balance of plant is similar for the two cases and thus any inaccuracies in the costs of the balance of plant which incorporates new or developing technologies would "cancel' off while performing the differential economics. It should be also noted that the cost of the combined cycle unit in the IGCC case is quite well defined.

The IGCC case utilized the partially steam cooled G technology gas turbine while higher plant efficiency and lower total plant cost may be expected with the H technology gas turbine for the IGCC. In a gasification plant, as the power block becomes more efficient, the size of the gasification plant (per unit of power produced) decreases since less fuel is required by the power block on a kW basis. Since the cost of the gasification system represents as much as 70% of the total plant cost [Shelton and Lyons, 2000], a reduction in the overall plant cost may be expected. As the firing temperature is further increased, even greater improvements in the plant economics may be expected for the IGCC option. Thus, as further advances in gas turbine technology are made with respect to firing temperature due to improvements in materials and cooling technology, the required SOFC system cost will have to be < $400/kW to be competitive on a cost of electricity basis with the IGCC.

OTHER ADVANCED DESIGN CONCEPTS

IGFC Near "Zero Emission" Case

An IGFC plant design concept to capture carbon emissions is depicted in Figure 2. The major distinguishing features of this configuration as compared to the previously described IGFC Power Only Case include an O_2 blown ATR, the O_2 being supplied by an ion or O_2 transport membrane (ITM / OTM) unit [Richards, 2001; Armstrong], separate SOFC anode and cathode exhaust streams, and a shift conversion unit followed by a high temperature H_2 separation membrane [Roark, Machay and Sammells, 2003], in order to capture the gaseous carbon emissions from the gasifier (95% of the total carbon fed to the gasifier) as CO_2 for sequestration while recovering the separated H_2.

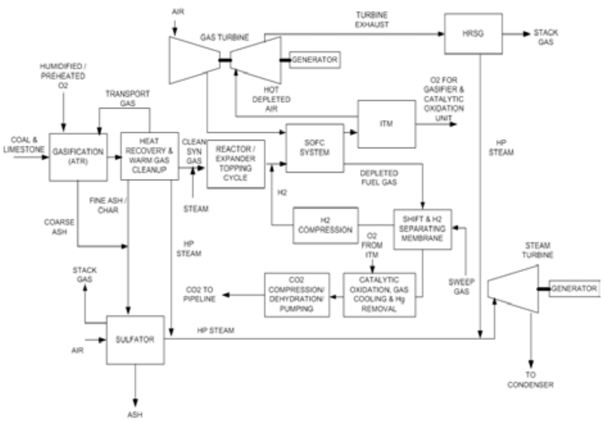

Figure 2: Block Flow Sketch – IGFC "Near Zero Emission" Plant

The SOFC anode exhaust gas after heat recovery is fed to a shift unit where the remaining CO is converted to CO_2 while generating H_2. The shifted gas now mainly CO_2 with the H_2 formed and residual CO content goes to a H_2 membrane separator to capture the H_2 which is compressed and recycled to the SOFC. Alternately, a shift / membrane unit can be utilized. The non-permeate is fed to a catalytic combustor using O_2 from the membrane oxygen plant to fully oxidize the small amounts of any remaining CO and H_2, leaving CO_2, H_2O, and a very small amount of O_2 in the stream. This stream is cooled and then pressurized (and dehydrated) to 13,800 kPa, similar to the previous case.

A fraction of the hot depleted air exiting the SOFC is preheated to about 800ºC, the temperature required by the ITM (or OTM) unit for air separation by directly combusting in it a small fraction of the recovered H_2, while the remainder of the SOFC exhaust is bypassed in order to minimize the fuel (H_2) used in preheating the feed gas to the ITM / OTM unit. In the ITM / OTM unit, O_2 is removed from the vitiated air and exits the unit at sub-atmospheric pressure. The O_2 is cooled and compressed to gasifier pressure with a small side stream going to the catalytic "cleanup" for oxidizing combustibles remaining in the CO_2 stream. The non-permeate from the ITM / OTM, now reduced in mass flow and slightly in pressure, is combined with the fraction of the cathode exhaust air that bypassed the ITM / OTM and is then expanded in the gas turbine while exhausting to an HRSG. The gas turbine output is significantly reduced because of its low turbine inlet temperature, around 750ºC and the reduced flow.

The gasifier O_2 after compression is humidified in a counter-current packed column utilizing process condensate and is then sent to the mixing zone of the ATR gasifier. The humidification operation generates the entire steam required for the ATR while reducing the amount of waste-water to be treated.

The overall plant performance is presented in Table 5.

Table 5: Performance Summary - IGFC Near "Zero Emission" Case

Coal Feed Rate (as Received), MT / D MWt (HHV)	2241 703.6
Fuel Cell Power, MW	260.7
Gas Turbine Power, MW	11.5
Steam Turbine Power, MW	107.1
Methanated Syngas Turbo-Expander Power, MW	4.9
Total Gross Power Generated, MW	384.2
Internal Power Consumption, MW	35.3
Net Electric Power (at Generator Terminals), MW	348.9
Overall Thermal Efficiency, % HHV	49.6

The plant consumes 2241 MT/D of the bituminous coal while producing 349 MW of electric power and capturing 95% of the CO_2 evolved. The calculated cell current density at a cell voltage of 0.75V was 164 mA/cm^2. The resulting net thermal efficiency of the plant at 49.6% (HHV) is significantly higher than that for an IGCC plant also designed for near zero emission which is estimated around 33% (HHV) based on data published by Rao and Stobbs, 2003. Thus, the use of hybrid technology is synergistic in plants deigned for carbon capture.

IGFC "Advanced FutureGen" Case

The DOE has made announcements regarding the building of a "FutureGen" plant, one that coproduces H_2 while recovering the CO_2. H_2 is being touted as the clean transportation fuel of the future for automobiles powered by fuel cells. Thus, this case is included in the analysis in order to quantify the coproduction of merchant grade H_2 while all emissions including CO_2 are controlled while utilizing the advanced technology. This coproduction plant should be able to duty cycle between fuel production versus power while taking advantage of other synergies of coproduction such as energy integration.

Such a FutureGen plant is depicted in Figure 3. This plant is similar to the previously described IGFC "near Zero Emission" case. A distinguishing feature of this configuration is that it includes a shift conversion with high temperature H_2 separation membrane unit upstream of the SOFC system.

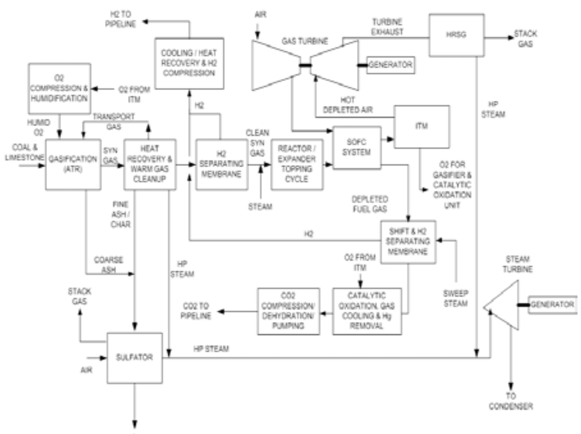

Figure 3: Block Flow Sketch – IGFC "Advanced FutureGen" Plant

The plant consumes 2241 MT/D of the bituminous coal while producing 155 MW of electric power, exporting 1.86 x 10^6 nM^3/D of H_2, and capturing 95% of the CO_2 evolved. The calculated cell current density at a cell voltage of 0.75V was 111 mA/cm^2 which is significantly lower than the previous case since a significant portion of the H_2 is removed for export from the anode feed gas in the upstream shift/membrane unit. The overall thermal efficiency of this coproduction facility is 61.1% utilizing the following expression while exporting 39% of the energy content of the coal in the form of H_2 (on an HHV basis):

Thermal efficiency = (net export electric power + HHV contained in exported H_2) / (HHV contained in the total coal feed).

The overall plant performance of this case along with that for an operating scenario where the net power generated is increased by as much as 60% (increased from the 155 MW to 250 MW) while exporting about 50% less H_2 are summarized in Table 6.

Table 6: Performance Summary - IGFC "Advanced FutureGen" Case

Coal Feed Rate (as Received), MT / D MWt (HHV)	2241 703.6	
H_2 Exported	**High**	**Low**
Fuel Cell Power, MW	103.9	184.6
Gas Turbine Power, MW	11.5	10.5
Steam Turbine Power, MW	81.9	91.9
Methanated Syngas Turbo-Expander Power, MW	3.0	3.9
Total Gross Power Generated, MW	200.3	290.9
Internal Power Consumption	45.4	41.1
Net Electric Power (at Generator Terminals), MW	154.9	249.8
H_2 Exported, MWt (HHV)	275	136
% of Coal HHV	39.1	19.4
1000 Nm^3 / D	1,860	920
Kg / D	167,400	82,900
CO_2 Capture, % of Carbon in Coal + Limestone	95	95
Overall Thermal Efficiency, % HHV	61.10	54.83

These two operating cases show an estimate of the upper and lower bounds for the relative amounts of H_2 and power that may be produced by a given plant while maximizing the overall plant thermal performance for the set of design constraints chosen for the study and for the set of technologies employed in the configuration as developed for this case. One of these design constraints is that the air flow to the gas turbine can be reduced by a maximum of 20% while a minimum of 100% excess air is utilized in the SOFC (183% excess air is utilized in the SOFC for the high H_2 export case versus 100% excess air for the low H_2 export case while providing the entire amount of the cathode exhaust gas as feed gas to the ITM / OTM unit). Thus, it can be seen from the data that going from the high H_2 (or low power) export scenario to the low H_2 (or high power) export scenario the gas turbine generates 10% less power and the steam turbine generates 12% more power while it is the SOFC that produces most of the additional power. This tends to maintain a high electrical efficiency for the plant at the two operating scenarios since the turndown or part-load characteristics of the SOFC are excellent from a thermal efficiency standpoint.

CONCLUSIONS

Based on the results of this study, following conclusions may be drawn with respect to the development needs of the major subsystems for these advanced power plants to meet the Vision 21 goals.

Gas Turbine

The development needs for the gas turbine in these hybrid applications are that large (~100 MW) turbines with the following attributes are required:

- Recuperation
- Low firing temperature
- Intercooling (not essential but a desirable feature for high specific power)
- Combustors accepting hot and depleted fuel and air when gas turbine combustors are used for oxidation of the anode exhaust gas
- Oil free bearings.

Fuel Cell

The development needs for the SOFC systems are:

- Higher current density materials without extensive use of exotic / expensive materials in order to limit the physical size of the fuel cell stack modules and also minimize the high temperature piping and manifolding, and thus reduce the overall cost of the system. The estimated target installed cost of the SOFC system in a coal based plant is \$400/kW (with all contingencies and engineering fee included) which results in an overall cost of electricity of 39 Mills/kWh (10^{th} year levelized cost) that is identical to that of the IGCC case (without the SOFC). It should be noted that this IGCC plant utilizes the partially steam cooled G technology gas turbine while higher plant efficiency and lower total plant cost may be expected with the H technology gas turbine. In addition, as the firing temperature is further increased, even greater improvements in the plant economics may be expected for the IGCC option. Thus, as further advances in gas turbine technology are made with respect to firing temperature due to improvements in materials and cooling technology, the required SOFC system cost will have to be < \$400/kW to be competitive on a cost of electricity basis with the IGCC. Note that no economic credit has been given to the SOFC based plant for its lower CO_2 emission on a per kW basis resulting from its lower heat rate.
- Fuel cells operating with low air to fuel ratio in order to achieve the Vision 21 efficiency goals when the gas turbine development needs are limited to non-reheat systems. Management of heat generated within the cells becomes more challenging and internal reforming will help.
- Separate anode and cathode exhausts from the SOFC for plants with CO_2 capture. SOFCs with high operating pressures (in the region of 1,800 to 2,000 kPa) in order to increase the thermal performance as well as increase the current density in the fuel cell while decreasing the size of equipment including that of the heat exchangers and the ITM / OTM in plants with CO_2 capture.

Balance of Plant

The development needs for the balance of plant systems are:

- Warm (300 to 400ºC) gas cleanup in order to make the syngas suitable for an SOFC with special emphasis on the following species: particulates, alkalis, chlorides, sulfur compounds, SiO_2, NH_3 and HCN (to avoid any potential for NOx generation during combustion of anode exhaust).
- High temperature shift / membrane separation of H_2 in the case of H_2 coproduction and / or zero emission plants.
- Other technology development requirements consist of ionic membrane separation of air, lower temperature gasifiers such as the ATR while maintaining high carbon conversion ($\geq$ 95% for bituminous coals).

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