Conversion of Fossil and Biomass Fuels to Electric Power and Transportation Fuels by the High Efficiency Integrated Plasma Fuel Cell (IPFC) Energy Cycle

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ABSTRACT

The IPFC is a high efficiency Integrated Plasma Fuel Cell (IPFC) Energy Cycle. An electric arc Hydrogen Plasma Black Reactor (HPBR) decomposes carbonaceous fossil (natural gas, petroleum, and coal) and biomass fuels to elemental carbon, hydrogen and CO, the latter only when the fuel contains oxygen as in coal and biomass (wood, agricultural and municipal solid waste). The gaseous hydrogen and CO syngas is cleaned and sent to a water gas shift reactor to adjust H_2/CO ratios to 2.0. The adjusted syngas is then converted to liquid transportation (gasoline or diesel) fuels by the F-T (Fischer-Tropsch) catalytic synthesis process. Other carbonaceous products that can be produced indirectly are methane and methanol. The elemental carbon is sent to a molten carbonate direct carbon fuel cell (DCFC) where electricity is produced. A small part of the electricity is used in the HPBR and the major fraction is product. The IPFC-FT produces two major products, electric power and transportation fuels. Process flow sheets, and mass and energy balances are presented. Based on laboratory and plant data, thermal efficiencies of the IPFC process for conversion of feedstock fuel to electricity and transportation fuels are determined to vary from 70% to as high as 83% depending on the fuel feedstock. For coals, the efficiency ranges between 79.8 and 83.2%. The efficiencies for coal are at least 33% higher than current integrated gasification combined cycle plants with Fischer-Tropsch addition (IGCC-FT) at 60.2% thermal efficiency. Accordingly, the IPFC-FT plants have lower CO_2 emissions than the IGCC-FT plant. The CO_2 emissions are proportionately reduced and are in concentrated form ready for sequestration or other use such as for Enhanced Oil Recovery (EOR). Preliminary cost estimates indicate that the IPFC-FT process with US coal feedstock can produce electricity at costs from 27.4 to 30.6 mills/kWh(e) and co-produce gasoline or diesel at from \$0.96 to \$1.11/gal. IPFC-FT gasoline costs are competitive with refinery cost at \$30.30 to \$35.00/Bbl of crude oil. The current IGCC-FT process estimate is much higher at \$1.65/gal, which is only competitive at very high crude oil prices (\$52.20/Bbl). For coal feedstocks, IFPC-FT by raising the selling price of electricity to the range of

40.73 to 47.27 mills/kWh(e) (which is even less than current steam plant cost of 50 mills/kWh(e)), the gasoline by-product cost could be reduced to zero. The IPFC-FT plants can be economically very attractive compared to conventional combined cycle plants because of lower capital investment and higher efficiency. The IPFC-FT is basically an electric power producer with production of transportation fuel as a by-product. Further work is necessary to investigate the flexibility of product ratio and economics of the IPFC-FT process. It is now necessary to verify these estimates by laboratory, pilot plant and engineering design studies for scaling up to industrial plant capacity.

Process Description

Previous papers have described new highly efficient electric power and hydrogen energy cycles applying the basic IPFC concept.[1-4] In this paper we expand the IPFC concept and describe co-product processes for producing electricity and transportation fuels by conversion of fossil and biomass fuels feedstocks. The IPFC concept (Integrated Plasma Fuel Cell) Energy Cycle starts with decomposing the fossil or biomass fuel in a Hydrogen Plasma Black Reactor (HPBR). In the HPBR, the fossil and biomass fuels are introduced into an electric arc in a hydrogen stream between carbon electrodes and are thermally decomposed to elemental carbon and hydrogen and carbon monoxide (the latter only when the fuel contains oxygen as in coal and biomass) at temperatures of the order of 1500^{o}C.[5, 6] It should be noted that the hydrogen in the plasma assists in the decomposition reaction in reducing energy requirements. The carbon is separated from the hydrogen gas stream and is dispersed in a molten carbonate salt (sodium or potassium) which is fed to the anode compartment of a Direct Carbon Fuel Cell (DCFC)[4, 8-9]. Electric power is produced in the DCFC by the electrochemical reaction of oxygen from the air fed to the cathode with the carbon at the anode through the media of the carbonate ion transferred by the molten carbonate electrolyte to produce concentrated CO_2. The CO_2 from the DCFC is undiluted and is available for sequestration or other use. A small part of the power produced in the DCFC is used to provide the electricity for powering the electric arc in the HPBR. The carbon can be separated from the HPBR hydrogen gas stream either in cyclones or in bag filters or by capturing in the liquid molten carbonate for transport into the DCFC. When ash is present (mainly from coal), the ash at the high temperature of the plasma will become molten, forming a glass and being denser and of different particle size than the carbon, can be separated in a fluidized bed or in cyclones. Engineering details of the separation and capture in the molten carbonate are yet to be determined. Any sulfur in the fuel will become H_2S in the hydrogen stream and can be removed with adsorbents or reacted with ZnO to sulfide and subsequently removal as SO_2 or sulfur. Any nitrogen in the coal feedstock would be converted to ammonia and recovered or removed with lime or decomposed to nitrogen. The cleaned gases from the HPBR contain essentially H_2 or H_2 and CO syngas. Part of the hydrogen containing gas is recycled to maintain the hydrogen plasma.

Figure 1 shows the central and basic part of the IPFC process, which combines the HPBR with the DCFC to produce the H_2 or H_2 + CO syngas. When there is no oxygen present in the fuel feedstock (as in natural gas and petroleum) no CO is formed and the hydrogen is sent to a reverse water gas shift reactor (WGS) for reaction with CO_2 to produce the H_2 and CO syngas stream. The CO_2 is obtained from the DCFC. The reverse shift WGS is operated to produce a H_2/CO ratio syngas of 2.0 or more needed for producing liquid synfuels. When oxygen is present in the fuel (for coal and biomass) the H_2 and CO which is formed is reacted with steam or CO_2 in a water gas shift reactor (WGS) to produce a syngas with a ratio of 2.0. The WGS reactions are essentially thermally neutral (to condensed water). If the ratio of H_2/CO in the feedstock is greater than 2.0 the reverse shift is used with CO_2 reactant (obtained from the DCFC) to bring the H_2/CO down to 2.0 and when the H_2/CO is less than 2.0 the forward water gas shift with steam as reactant is used to bring the H_2/CO up to 2.0. The adjusted H_2/CO syngas can then be sent to one of several types of catalytic reactors.

In Figure 2 only the Fischer-Tropsch catalytic reactor is shown for producing gasoline and diesel hydrocarbon fuels. The H_2/CO syngas can also be sent to a catalytic methanation reactor to produce essentially methane (SNG substitute natural gas) or to a catalytic methanol reactor to produce methanol. The methanol can subsequently be converted to gasoline in a dehydration reactor.[10] The methanol to gasoline (MTG) was actually practiced on an industrial scale in New Zealand. These catalytic reactors can be applied in a fashion to mainly produce gasoline and diesel liquid transportation fuels, which have the generic formulae $(CH_2)_n$. The catalytic reactions are exothermic and require heat exchangers and recycle streams to obtain essentially complete conversion of the syngas to the synthetic fuels at kinetically optimum temperatures. For Fischer-Tropsch (F-T) generally, when an iron catalyst is used in F-T synthesis, diesel compounds (C_{16}-C_{21} hydrocarbons) are formed. With cobalt catalyst lighter gasoline compounds (C_8-C_{16} hydrocarbons) are formed.[10-12] There has been much experience with F-T syntheses in South Africa.

Mass and Energy Balance

The mass and energy balances are derived from the stoichiometry of the particular feedstock and the chemical reactions taking place in each of the reactors shown in flowsheet Figures 1 and 2. The energetics for each of the process reactions is derived from the thermodynamic enthalpies of the reactants and products. The basic composition and thermodynamic data of the fuel feedstocks used in this study are shown in Table 1. For natural gas, the fuel is taken as methane CH_4 and for petroleum the stoichiometry composition averages as $CH_{1.7}$ and for the coal and biomass the stoichiometrics are calculated from the compositions, taking into account the moisture and ash. The following displays the reactions, conditions and energetics for each of the feedstocks operating in each of the IPFC process reactors. The reverse shift reactor operates at higher temperatures (>450^oC) to produce CO and the forward shift at lower temperatures (<250^oC) to produce CO_2.

Natural Gas CH_4

Reactor	Temp ^oC	Reaction	Enthalpy, ΔH* kcal/gmol
HPBR	1500	$CH_4 = C + 2H_2$	+18.0
DCFC	800	$C + O_2 = CO_2$	-94.0
WGS Reverse	>450	$0.667H_2 + 0.667CO_2 = 0.667CO + 0.667H_2O$	0.0
F-T	225	$1.333H_2 + 0.667CO = 0.667CH_2 + 0.667H_2O$	-32.9

*From the energetic calculations, it should be noted, that the enthalpy of decomposition for natural gas only varies from +18 kcal/mol to +21 kcal over the temperature range from 25^oC to 1500^oC. The heat of the HPBR effluent gases is recovered by heat exchange to preheat the feed. The exothermic enthalpy of the oxidation of carbon to CO_2 is invariant from 25^oC to 800^oC. The WGS enthalpy of reaction is essentially zero (to liquid H_2O and heat recovery). A reverse WGS is used to adjust $H_2/CO = 2.0$. CH_2 is the nominal unit carbon stoichiometry for gasoline and diesel fuel. The heat of formation ΔH for CH_2 = -7.0 kcal/gmol which is used to determine the exothermic heat of the F-T reaction.

Petroleum – $CH_{1.7}$

Reactor	Temp ^oC	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	$CH_{1.7} = C + 0.85H_2$	+3.0*
DCFC	800	$C + O_2 = CO_2$	-94.0
WGS Reverse	>450	$0.283H_2 + 0.283CO_2 = 0.283CO + 0.283H_2O$	0.0
F-T	225	$0.566H_2 + 0.283CO = 0.283CH_2 + 0.283H_2O$	-14.0

*It should be noted it takes less energy to decompose petroleum than natural gas (methane). A reverse WGS is needed to adjust H_2/CO to 2.0

N. Dakota Lignite – $CH_{0.77}O_{0.24}$ (MAF)

Reactor	Temp °C	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	$CH_{0.77}O_{0.24} = 0.24CO + 0.76C + 0.385H_2$	+ 3.6*
DCFC	800	$0.76C + 0.76O_2 = 0.76CO_2$	-71.4
WGS	<250	$0.032CO + 0.032H_2O = 0.032CO_2 + 0.032H_2$	0.0
F-T	225	$0.417H_2 + 0.208CO = 0.208CH_2 + 0.208H_2O$	-10.3

*The energy required to decompose the lignite is somewhat more than that required for petroleum, both of which are lower than natural gas. It is believed that the hydrogen in the plasma assists in the decomposition reaction in reducing energy requirements. A forward WGS is needed to adjust H_2/CO to 2.0.

Wyodak Coal – $CH_{0.84}O_{0.19}$ (MAF)

Reactor	Temp °C	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	$CH_{0.84}O_{0.19} = 0.81C + 0.19CO + 0.42H_2$	+ 2.4
DCFC	800	$0.81C + 0.81O_2 = 0.81CO_2$	-70.1
WGS	>450	$0.013H_2 + 0.013CO_2 = 0.013H_2O + 0.013CO$	0.0
F-T	225	$0.407H_2 + 0.203CO = 0.203CH_2 + 0.203H_2O$	-10.1

Since the H_2/CO ratio for Wyodak Coal is slightly over 2, a reverse shift with CO_2 is necessary to bring the H_2/CO ratio down to 2.0. It appears from the enthalpy of decomposition for this coal is the lowest of all the fossil fuels investigated in this report. This will result in a high thermal efficiency for Wyodak feedstock.

Beluga Coal – $CH_{0.97}O_{0.24}$ (MAF)

Reactor	Temp °C	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	*$CH_{0.97}O_{0.24} = 0.24CO + 0.76C + 0.485H_2$	+ 3.3
DCFC	800	$0.76C + 0.76O_2 = 0.76CO_2$	-71.4
F-T	225	$0.485H_2 + 0.24CO = 0.24CH_2 + 0.24H_2O$	-12.0

*Since the H_2/CO molar ratio on decomposition of the Beluga coal is almost exactly 2.0, the $H_{2\,+}$ + CO syngas can go directly to the F-T converters, and there is no need for a WGS.

Kentucky Bituminous Coal – $CH_{0.81}O_{0.08}$ (MAF)

Reactor	Temp °C	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	$CH_{0.81}O_{0.08} = 0.92C + 0.08CO + 0.41H_2$	+ 4.8*
DCFC	800	$0.92C + 0.92O_2 = 0.92CO_2$	-86.5
WGS Reverse	>450	$0.083H_2 + 0.083CO_2 = 0.083H_2O + 0.083$	0.0
F-T	225	$0.327H_2 + 0.163CO = 0.163CH_2 + 0.163H_2O$	-8.1

*Since the ratio of H_2/CO in the decomposed feedstock is much higher than 2.0, a reverse shift WGS is needed. The energy required to decompose the bituminous coal is slightly higher than for the lignite and Beluga Coal.

Biomass (Wood) – $CH_{1.38}O_{0.59}$ (MAF)

Reactor	Temp °C	Reaction	Enthalpy, ΔH kcal/gmol
HPBR	1500	$CH_{1.38}O_{0.59} = 0.41C + 0.59CO + 0.69H_2$	+12.7*
DCFC	800	$0.41C + 0.41O_2 = 0.41CO_2$	-38.5
WGS	<250	$0.163CO + 0.163H_2O = 0.163CO_2 + 0.163H_2$	0.0
F-T	225	$0.853H_2 + 0.427H_2 = 0.427CH_2 + 0.427H_2O$	-21.1

*Since the ratio of H_2/CO in the decomposed feedstock is much lower than 2.0, forward shift WGS is needed. The energy required to decompose the biomass is higher than for the coals and petroleum but less than for natural gas.

Thermal Efficiency of IPFC

Based on the above reaction stoichiometries, the thermodynamics and the thermal efficiency of each of the major process units (DCFC, WGS, and HPBR), Table 2 summarizes, the composition of the plasma decomposition products, electrical power and transportation fuel (gasoline and diesel) yields, and the overall thermal efficiency of the entire process cycle for the suite of feedstock fuels investigated in this report. The energy balance takes into account the thermal process efficiency for each of the reactors as is shown in Table 2, in the same manner as given previously when electricity and hydrogen is produced.[1-4] The thermal efficiency is defined as the sum of the energy values of the electricity and the gasoline divided by the higher heating value (HHV) of the feedstock. Table 2 indicates the thermal efficiency of the IPFC varies from a low of 70.4% for biomass as feedstocks to a high of 83.2% for the Wyodak sub-bituminous coal feedstock. The thermal efficiency of the coal feedstocks varies within the narrower range of 79.8% to 83.2%. Table 3 shows the thermal efficiencies, the product yields and distribution per unit of fuel feedstock and CO_2 emissions in units of lbs CO_2/kWh of total product energy output. The ratio of electric power to transportation fuel production varies strongly depending on the composition of the fuel feedstock. For natural gas, the ratio of electric power to hydrocarbon fuel is approximately 0.5, whereas for petroleum and the coals, the ratio varies from approximately 1.8 to 2.8. This is important from an economic point of view because the electricity selling price per unit of energy is currently 2 times as high as gasoline or diesel fuel. Recently, however, the latter prices have been increasing which can change the effect of this ratio. Because the efficiencies for IPFC are in the range of 70 to 80%, the CO_2 emissions as far as electric power is concerned is about half that of conventional steam power plants at 38% thermal efficiency, assuming that all CO_2 from IPFC emissions are credited to electric power alone.

The IPFC must be compared to an IGCC (Integrated Combined Cycle) plant producing the same relative quantities of electricity and liquid fuels. Figure 3 gives the essential flowsheet for IGCC, which includes a feedstock steam gasifier, an oxygen air liquefaction unit; a water has shift reactor, and a Fischer-Tropsch converter to produce the gasoline or diesel from the syngas. To produce power a combined power cycle, which includes a high temperature combustion turbine generator and backend steam turbine Rankine cycle generator is used to take a fraction of the gas from the gasifier to produce electricity in the same ratio to the transportation fuel production as for the IPFC. Applying the same methodology for determining the efficiency of the IGCC system as was used for the IPFC, results using the N. Dakota Lignite as feed is obtained. However, first the efficiency of production of transportation fuel alone by steam gasification is determined as follows:

North Dakota Lignite – $CH_{0.77}O_{0.24}$ (WAF) producing gasoline by steam gasification

Reactor	Temp ^oC	Reaction	Enthalpy, ΔH kcal/gmol
		North Dakota Lignite	
Gasifier steam	850	$CH_{0.77}O_{0.24} = 0.76H_2O = CO + 1.145H_2$	+35.5
Combustion	850	$0.401CH_{0.77}O_{0.24} + 0.474O_2 = 0.401CO_2 + 0.401\ H_2O$	-44.4
WGS	<250	$0.285CO + 0.285H_2O = 0.285CO_2 + 0.285H_2$	0.0
F-T	225	$1.430H_2 + 0.715CO = 0.715CH_2 + 0.715H_2O$	-35.3

In the above it is assumed the gasifier process efficiency is 80% and that enough lignite must be combusted with oxygen to supply the endothermic heat of reaction for the steam gasification (35.5/0.8 = 44.4). The thermal efficiency for production of gasoline from lignite by gasification alone without electricity production taking into account the fuel burned internally and the energy for the air liquefaction (300 kWh/ton O2) is as follows:

Efficiency of Production of Transportation Fuel by IGCC alone =

$$\frac{\text{HHV of Transportation Fuel Yield}}{\text{Fuel Burned + Feedstock fuel + Energy for Air Liquefaction}} \times 100$$

$$\text{Fuel Efficiency for IGCC} = \frac{0.715 \times 154.5}{(0.401 + 1.00)\ 110.3 + 3.6} \times 100 = 69.7\%$$

The thermal efficiency for production of electricity alone by the IGCC is, at best, about 55%.[13] The IPFC plant using North Dakota Lignite is 82% efficient with 64.5% of the total product energy output as electricity and 35.5% as gasoline. Applying the same product allocation to IGCC, that is 64.5% of the product energy to electricity at 55% thermal efficiency and 35.5% to gasoline at 69.7% thermal efficiency, the overall thermal efficiency of energy in products to energy in feed amounts to 60.2% for IGCC-FT. The overall thermal efficiency for IPFC at 82.0%, is thus a significant 36% higher than the IGCC-FT competitor efficiency of 60.2%. The CO_2 emission for IGCC-FT is found to be 0.992 lbs/kWh energy output, which is 36% higher than the IPFC-FT emission at 0.729 lbs CO_2/kWh as shown in Table 3 and Table 4.

A further assessment of CO_2 emission from IPFC plants is presented in Table 4 for five of the feedstocks and compared to the CO_2 emissions from IGCC plants at similar production ratios of electricity to gasoline. The reduction of CO_2 emission from IPFC plants is 19% to 31% lower than IGCC plants. The CO_2 emissions are about 26% lower particularly for the coal feedstocks. It should also be noted that the IFPC plant puts out 76.4% less CO_2 per kWh of electricity than a conventional coal steam Rankine cycle power plant, which operates at 38% efficiency for electricity. Furthermore, the IGCC plant CO_2 emission is diluted with atmospheric nitrogen due to combustion in the combined cycle power plant whereas the CO_2 is undiluted coming from the DCFC in the IPFC plant. Besides the advantage of CO_2 sequestration, the CO_2 from the DCFC can be used directly in the water gas shift (WGS) reactor when required for a reverse shift and this can be taken into account in reducing the emissions of CO_2 from the IPFC. Also, the IPFC plants using N. Dakota lignite emits 36.4% less CO_2 per kWh of gasoline than a conventional coal gasification synfuel plant operating at 65% efficiency.

Preliminary Economic Analysis

A preliminary economic analysis is given below, following the methodology and unit costs given in the earlier IPFC electric power and hydrogen report.(4) A summary of the unit capital costs of the reactors are given in Table 5 and the unit feedstock fuel costs in Table 6. The production cost of electricity and transportation fuel for the entire suite of fuel feedstocks is given in Table 7. It appears that the natural gas and petroleum production cost estimates for gasoline at $1.44/gal are about 30 to 50% higher than the coal and biomass feedstock plants at $0.96 to $1.14/gal. This is mainly due to the higher cost of natural gas and petroleum compared to coal and biomass. The same holds true for electricity costs. However, the interesting point here is that the equivalent electricity production costs are all under 50 mills/kWh(e), which is the current production cost for coal-fired Rankine Cycle steam power plants. For comparison, an IGCC-FT plant cost estimate for producing electricity and gasoline at about the same production ratio as the IPFC-FT plant is shown in the last column of Table 7 for N. Dakota Lignite. Thus, IGCC at $1.65/gal is 65% higher than IPFC at $1.00/gal. The main factor, which increases the cost of production of IGCC, is the capital cost required for the IGCC-FT which is due in part to the combined cycle power plant and the need for an oxygen plant. That is why the DOE is seeking new ideas to increase the efficiency of combined cycle plants and to reduce capital cost. The IPFC-FT plant holds out the promise of achieving this goal.

In order to compete with gasoline costs today the IPFC-FT plant must compete with at least $0.80/gal, which is the cost at the oil refinery with a cost for petroleum at $25/bbl. Excluding delivery and taxes this is based on 25% of the cost of gasoline due to refining cost and 75% is the crude oil cost.(14) With coal feedstock, gasoline costs from the IPFC-FT plants are higher than $0.80/gal and are, therefore not competitive. However, oil has recently increased to $35/bbl, which increases the cost of gasoline at the refinery to roughly $1.10/gal, and the costs now become competitive. The last line in Table 7 gives the breakeven cost of a barrel of crude oil for IPFC-FT to compete with refinery costs. For the coal plants this varies between $30 and $35/Bbl.

It should be noted that electricity at 50 mills/kWh is equal to $14.65/MMBTU while gasoline and diesel at $0.80/gal = $6.65/MMBTU or at $1.10/gal = $9.16/MMBTU which means that on an energy value basis, electricity is at least 60% to 120% more valuable than gasoline as a consumer commodity. Since the IPFC-FT plant produces two products, it is instructive to determine the cost of one if the other is priced at the same level as its competitor. Currently, the cost of production of electricity at efficient coal burning steam plants is about 50 mills/kWh(e) as mentioned above. As shown in Table 7, for IPFC-FT plants, all feedstock forms produce electricity below 50 mills kWh while the gasoline is above \$0.80/gal based on \$25/Bbl of oil. Thus, if the electricity is sold at the same cost level as the best conventional plants we can calculate the cost of the co-product gasoline while maintaining the same total income to the IPFC plant as originally calculated. When this is done, the gasoline cost is considerably reduced. When the calculated cost for gasoline becomes negative (less than zero) under this assumption, the cost of electricity is reduced only to a level below 50 mills/kWh(e) so as to maintain a zero cost for gasoline. These estimates are now shown in Table 8. The natural gas and petroleum estimates at\$1.06 and \$0.91/gal respectively, are still too high compared to oil refinery costs of \$0.80/gal (at \$25/Bbl oil) but become competitive with \$1.10/gal (\$35/Bbl. oil). The reason for this is due to the high natural gas and petroleum feedstocks cost. The coal plants, on the other hand, can all produce zero selling price of gasoline even when the electricity selling cost is less than 50 mills/kWh. The Kentucky bituminous coal is one of the more economical coal feedstocks yielding a minimum electricity selling cost of 41.63 mills/kWh(e) at zero cost for the gasoline. This results because the Kentucky bituminous coal produces the highest electricity production fraction (73.4% from Table 3) and as we have seen above electricity is more valuable than gasoline in today's economy. Wyodak coal also shows a 40.73 mill/kWh(e) electrical cost at zero gasoline cost because the efficiency is highest (83.2%). The opposite is true of biomass where the electricity production fraction is very low (16.9%) although at 50 mills/kWh(e) for electricity selling cost for gasoline is \$0.84/gal, which is slightly higher than petroleum refinery costs of gasoline production at \$25/Bbl. And as far as IGCC-FT is concerned, even at 50-mills/kWh electricity, the gasoline production cost is much higher than refinery cost (\$1.24/gal, Table 8) requiring \$39.10/Bbl of oil. Table 8 also shows that in order for the refinery to produce gasoline at zero cost the price of crude oil would have to be negative at \$10.50/Bbl. Of course, this is hypothetical since no plant will pay for giving away gasoline for nothing. When gasoline is sold at the pump for \$1.75/gal (includes distribution and taxes) then the refinery production cost is \$1.10 with \$35/Bbl oil. The IPFC-FT gasoline can be sold for much less because the production cost is zero. The conclusion is that the IPFC-FT plant can be economically very lucrative.

However, we must consider the capacity factors for production. It should be noted that the coal fed IPFC-FT plants are basically electrical power producers with by-product gasoline production. The ratio of electricity to gasoline production varies from 1.6 (Beluga coal) to 2.8 (Kentucky bituminous). If we assume a large 1000 MW Kentucky Bituminous coal fed IPFC-FT plant, the electric power plant would operate at a level of 734 MW(e) and the gasoline production would be about 4000 Bbl gasolines per day. Compared to a present day oil refinery which range in capacity from between 20,000 and 100,000 Bbl/day the IPFC-FT gasoline capacity is relatively small. If we take Beluga coal feedstock the comparable values are 613 MW(e) power plant with a gasoline production of 5800 Bbl/day still a modest gasoline refinery. For a Wyodak coal the IPFC-FT plant produces 673 MW(e) electricity and 5300 Bbl/day of gasoline. However, the income to the IPFC-FT can be as much as 20% of the revenue to the plant. To match the gasoline to electricity demand in the U.S., a mitigating factor would be to improve the automotive vehicle fuel efficiency by building hybrid vehicles which have already been shown to obtain 3 times the mileage per gallon of current gasoline vehicles (20 mpg to 60 mpg). This would enhance the value of the IPFG coal plant in meeting the consumption demand of the public at a very economical cost. This is a subject to be explored in a future report. We must also explore IPFC-FT configurations that would increase the gasoline to electricity production ratio.

Conclusion

This report shows that the Integrated Plasma Fuel Cell process with the use of Fischer-Tropsch reactors (IPFC-FT) with carbonaceous feedstocks, which include the fossil fuels natural gas, petroleum, a suite of coals and biomass (wood), can yield total thermal efficiencies for producing electricity and transportation fuels varying from a low of 70.4% for biomass to a high of 83.2% for Wyodak sub-bituminous coal. For the suite of coals investigated, the thermal efficiencies are in a much narrower range from 79.8% for Kentucky bituminous to 83.2% for Wyodak sub-bituminous. These efficiencies are at least 33% higher than the current integrated gasification combined cycle (IGCC) plants with Fischer-Tropsch addition at 60.2% thermal efficiency. The CO_2 emissions from the IPFC-FT coal plants are 26% lower than from the equivalent IGCC plants. Furthermore, the CO_2 effluent emitted from the IPFC-FT plant is concentrated (which is not the case for IGCC) and can be directly sequestered, if required, to reduce the emissions to zero. The CO_2 can also be sold for use in enhanced oil recovery (EOR) and for coal bed methane (CBM) operations.

Preliminary IPFC-FT plant cost estimates indicate that the production costs for electricity and transportation fuels (gasoline and diesel) are 41 mills/kWh and $1.44/gal gasoline for natural gas and petroleum cost of $4/MMBTU and $25/bbl respectively. Natural gas and oil costs are currently volatile while U.S. coal feedstock costs are very stable and much lower in energy cost at $0.73/MMBTU for western lignite to $1.00/MMBTU for eastern bituminous coal. The IPFC-FT electricity production cost with U.S. coals varies from 27.4 to 30.6 mills/kWh(e) and the gasoline from 0.96 to $1.11/gal. Gasoline costs are competitive with refinery cost at $30.30 to 35.00 of crude oil. The IGCC-FT plant cost estimates are much higher at 46.9 mills/kWh(e) for electricity and $1.65/gal for gasoline and are only competitive at very high oil prices ($53.30/Bbl). By raising the electricity cost to not more than the current steam plant cost of 50 mills/kWh(e), and for the range of coal feedstock cases even less ($40.73 to 47.27 mills/kWh(e) for electricity), the gasoline cost from these coal feedstock IPFC-FT plants can be reduced to zero making these plants very lucrative. The IPFC-FT plant is basically an electric power producer with a by-product transportation fuel producer which is a significant factor in the economics. Further investigation for improving the gasoline to electricity ratio for IPFC-FT plants is warranted. It is now necessary to verify these estimates by performing laboratory pilot plant work, and engineering design studies for scaling up to optimum industrial capacity plant size.

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Table 1
Basic Data for Coal and Biomass Feedstocks used in the Study
Composition and Thermodynamic Data

Feedstock	Biomass Wood	Bituminous Kentucky Coal	Lignite N. Dakota Coal	Sub-bituminous Wyodak Coal	Alaskan Beluga Coal	Sewage Sludge
Composition (wt%)						
C	45.86	67.02	43.37	49.95	49.33	28.55
H	5.27	4.54	2.78	3.51	4.00	4.09
O	36.07	7.22	13.97	2.58	15.56	6.03
H_2O	11.67	8.60	30.10	26.40	21.78	9.82
Ash	0.66	8.34	8.30	6.03	8.67	36.53
S	0.04	2.85	0.81	0.60	0.12	1.36
N	0.43	1.43	0.67	0.93	0.54	3.62
Molar Composition (MAF)	$CH_{1.33}O_{0.59}$	$CH_{0.81}O_{0.08}$	$CH_{0.77}O_{0.24}$	$CH_{0.84}O_{0.19}$	$CH_{0.97}O_{0..24}$	$CH_{1.72}O_{0.42}$
MW	22.82	14.09	16.61	15.88	16.81	20.44
Heating Value (HHV)						
BTU/lb MF	-8800.0	-13650	-10254	-11730	-11082	-5510
kcal /kg MF	-4888.9	-7583.3	-5696.7	-6516.7	-6156.7	-3061.1
kcal / kg mol MAF	-112.8	-119.0	-110.3	-115.3	-117.5	-115.9
Heat of Formation (MAF)						
kcal/kg	-1214.4	-183.0	-593.0	-461.7	-584.9	-1769.7
ΔH_F kcal/mol	-27.7	-2.6	-9.8	-7.3	-9.8	-36.2
Heat Capacity						
(kcal/Kg MF / ^oC)	0.570	0.315	0.315	0.315	0.315	0.250
kcal/kg mol MF/ ^oC	13.00	4.44	5.23	5.00	5.30	5.11
Moisture						
Mol H_2O / mol C	0.170	0.086	0.462	0.353	0.294	0.230

MAF Moisture Ash Free
MF Moisture Free
HHV Higher Heating Value
MW Molecular Weight

Table 2
Integrated Plasma Fuel Cell (IPFC) Cycle
Electrical Power and Transportation Fuel Production
Mass and Energy Balance and Thermal Efficiency
Basis: 1 gmol of Feedstock Fuel

Fuel Feedstock	Natural Gas	Petroleum	N. Dakota Lignite	Beluga Coal	Wyodak Sub-bituminous	Kentucky Bituminous	Biomass Wood
Molar Composition (MAF)	CH_4	$CH_{1.7}$	$CH_{0.77}O_{0..24}$	$CH_{0..97}O_{0..24}$	$CH_{0.84}O_{0.19}$	$CH_{0.81}O_{0.08}$	$CH_{1..38}O_{0..59}$
(MW)	16.00	13.70	16.61	16.81	15.88	14.09	22.82
Plasma Decomp. Products							
C	1.0	1.0	0.76	0.76	0.81	0.92	0.41
CO	0	0	0.24	0.24	0.19	0.08	0.59
H_2	2.0	0.85	0.385	0.485	0.42	0.410	0.69
Ash, S,N (wt%)	0	~1.0	9.78	9.33	7.56	12.62	1.13
Enthalpy Decomposition, ΔH_D kcal/gmol Feedstock	18.0	3.0	3.6	3.3	2.4	4.8	12.7
Water Gas Shift, gmol CO and H_2 Per mol feed to obtain H_2/CO=2.0	0.667	0.283	0.032	-	0.013	0.083	0.163
Gasoline and Diesel Fuel Production gmol CH_2/mol Feed	0.667	0.283	0.208	0.240	0.203	0.163	0.427
Process Unit Thermal Efficiency and Energy Values in kcal/gmol Fuel							
Unit — Thermal Eff. - %							
DCFC — 90 (Elec.Prod.)	84.6	84.6	64.3	64.3	68.5	77.8	34.7
WGS — 100 (with Recycle)	-	-	-	-	-	-	-
HPBR — 60 (Energy Consumed)	-30.0	-5.0	-6.0	-5.5	-4.0	-8.0	-21.2
Product Distribution in Energy Values, kcal/gmol							
Net Electricity Production	54.6	79.6	58.3	58.8	64.5	69.8	13.5
F-T Gas, and Diesel Fuel*	103.5	43.7	32.1	37.1	31.4	25.2	66.0
Total Energy Output	158.1	123.3	90.4	95.9	95.9	95.0	79.5
HHV of Fuel Feedstock	212.0	149.0	110.3	117.5	115.3	119.0	112.8
Thermal Efficiency, %	74.5	82.8	82.0	81.6	83.2	79.8	70.4

*HHV of Gasoline or Diesel Fuel, Higher Heating Value, ΔH = 154.5 kcal/gm mol (HHV)

Table 3
Integrated Plasma Fuel Cell (IPFC) Cycle
Electrical Power and Transportation Fuel Production
Product Yields, Thermal Efficiency, and CO_2 Emission Distribution

Feedstock	Product	Yield	Thermal Eff., %	Product Energy Distribution, %	CO2 Emission Lbs/kWh
Natural Gas	Electricity, kWh(e)	75.6 kWh(e)/MSCF	25.7	34.5	0.061
MSCF – CH_4	Gasoline or Diesel Fuel	4.03 gal./MSCF	48.8	65.6	0.115
		Total	74.5	100.0	0.176
Petroleum	Electricity, kWh(e)	845 kWh(e)/Bbl	53.4	64.6	0.313
Bbl – $CH_{1.7}$	Gasoline or Diesel	13.2 gal/Bbl	29.4	35.4	0.172
		Total	82.8	100.0	0.485
N. Dakota Lignite	Electricity, kWh(e)	3704 kWh(e)/ton	52.9	64.5	0.471
Ton (MAF) – $CH_{0.77}O_{0.24}$	Gasoline or Diesel	57.9 gal/ton	29.1	35.5	0.259
		Total	82.0	100.0	0.729
Wyodak Sub-bituminous	Electricity, kWh(e)	4284 kWh(e)/ton	56.0	67.3	0.464
Ton (MAF) – $CH_{0.84}O_{0.19}$	Gasoline or Diesel	58.8 gal/ton	27.2	32.7	0.226
		Total	83.2	100.0	0.690
Beluga Alaskan Coal	Electricity, kWh(e)	3686 kWh(e)/ton	50.0	61.3	0.406
Ton (MAF) – $CH_{0.97}O_{0.24}$	Gasoline or Diesel	66.2 gal/ton	31.6	38.7	0.255
		Total	81.6	100.0	0.661
Kentucky Bituminous	Electricity, kWh(e)	5220 kWh(e)/ton	58.6	73.4	0.539
Ton (MAF) – $CH_{0.81}O_{0.08}$	Gasoline or Diesel	53.7 gal/ton	21.2	26.6	0.196
		Total	79.8	100.0	0.735
Biomass (wood)	Electricity, kWh(e)	620 kWh(e)/ton	11.9	16.9	0.103*
Ton/(MAF) – $CH_{1.38}O_{0.59}$	Gasoline or Diesel	86.7 gal/ton	58.5	83.1	0.498*
		Total	70.4	100.0	0.601*

*The net CO_2 emission for biomass fuel is zero because CO_2 emitted from IPFC is photosynthesized to biomass as fuel.
Units: MSCF = 1000 standard cu. ft. of natural gas; Bbl barrel = to 42 gallons; MAF – moisture ash free.
Energy content of 1 gal. gasoline = 120,000 BTU.

Table 4
Efficiency and CO2 Emission from Conventional (IGCC) and Advanced Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plants for Production of Electricity and Transportation Fuels

Fuel	Product Ratio Electricity / Gasoline	Thermal Efficiency %	CO_2 Emission Lbs CO_2/kWh Electricity	Gasoline	Total	% Reduction of CO_2 Emission from IGCC
Advanced - IPFC						
Natural Gas	0.53	74.5	0.061	0.115	0.176	31.2
Petroleum	1.82	82.8	0.313	0.172	0.485	19.0
N. Dakota Lignite	1.82	82.0	0.471	0.259	0.730**	26.5
Kentucky Bit. Coal	2.76	79.8	0.539	0.196	0.735	25.2
Biomass (wood)	0.20	70.4	0.103	0.498	(0.601)*	-
Conventional IGCC						
Natural Gas	0.40	73.1	0.073	0.183	0.256	
Petroleum	1.67	67.1	0.345	0.253	0.598	
N. Dakota Lignite	1.82	60.2	0.640	0.352	0.992	
Kentucky Bit. Coal	2.75	60.2	0.719	0.264	0.983	
Biomass (wood)	6.20	60.2	0.104	0.514	(0.618)*	

* For Biomass – no net CO_2 emission is zero because photosynthesis recycles CO_2.

** For N. Dakota Lignite – a conventional steam power plant at an efficiency of 38% emits 1.99 lbCO_2/kWh(e). The IPFC plant reduces the CO_2 emission by 76.4%. A coal gasification synfuel plant operating at 65% efficiency emits 0.407 lbCO_2/kWh(e) gasoline. The N. Dakota Lignite IPFC plant reduces the CO_2 emissions by 36.4%.

Table 5
Unit Capital Cost for
Integrated Plasma Fuel Cell Plant IPFC-FT
<u>Electric Power and Transportation Fuel Production</u>

	Unit	Unit Capital Cost, $/kW
HPBR	Hydrogen Plasma Black Reactor Converts Fuel to H_2, and CO Gas and Carbon	Gas and Oil Feed 200(1) Coal and Biomas Feed 250(2)
DCFC	Direct Carbon Fuel Cell Converts Carbon to Electricity with Molten Carbonate Electrolyte	500(3)
WGS	Water Gas Shift Reactor Converts CO to Hydrogen on Syngas (H_2 and CO)	100(4)
F-T	Fischer-Tropsch Reactor Converts Syngas to Gasoline and Diesel Transportation Fuel	300(4)

1) Based on Karbomont plant for oil and gas.
2) For solid fuel feedstocks coal and biomass add $50/kW to HPBR for solids handling.
3) John Cooper Ref. 9
4) Internal estimates

Table 6
Feedstock Fossil Fuel and Biomass Cost for IPFC-FT Estimates

Feedstock Fuel	Unit Cost[1]
Natural Gas	$4.00/MSCF ($4/MMBTU)
Petroleum	$25.00/BBL ($4.17/MMBTU)
Coals (MF)	
Lignite (Montana)	$12.40/ton ($0.73/MMBTU)
Bituminous Coal	$25.00/ton ($1.00/MMBTU)
Sub-bituminous	$15.00/ton ($0.88/MMBTU)
Biomass	$2.00/MMBTU

1) These costs were assumed to be consistent with earlier estimates for hydrogen production. Recently natural gas has increased to $6/MSCF and petroleum to $35.00/BBL. Coal has remained fairly stable.

Table 7
The Unit Plant Capital Investment and the Production Cost
Integrated Plasma Fuel Cell Plant (IPFC-FT)
For Electricity and Transportation Fuel Production

Fuel Feedstock	Natural Gas	Petroleum	N. Dakota Lignite Coal	Wyodak Sub-bituminous Coal	Beluga Alaskan Coal	Kentucky Bituminous Coal	Biomass Wood	IGCC with N. Dakota Lignite
Thermal Efficiency %								
Electricity Prod.	25.7	53.4	52.9	56.0	50.0	58.6	11.9	38.7
Gasoline* Prod.	48.8	29.4	29.1	27.2	31.6	21.2	58.5	31.3
Total Eff.	74.5	82.8	82.0	83.2	81.6	79.8	70.4	60.0
Unit Capital Cost Distrib. (Prorated) $/kW								
Plasma Reactor	200	200	250	250	250	250	250	
Carbon Fuel Cell	135	325	325	340	310	370	60	
Water Gas Shift	65	50	50	50	50	40	80	
F-T Reactor	200	100	100	100	110	90	250	
Contingency	50	50	50	50	50	50	50	
Total Unit Capital Invest.	690	725	775	740	770	800	690	1300 [x]
Combined Electricity and Gasoline* Unit Energy Production Cost – Mills/kWh								
Feedstock	18.32	17.19	3.04	3.10	3.68	4.28	9.70	4.14
Fixed charge @20% of Cap. kW	19.71	20.71	22.14	21.14	22.00	22.85	19.71	37.14
O&M	2.96	3.10	3.32	3.17	3.30	3.43	2.96	5.57
Total Prod. Cost	40.99	41.00	28.50	27.41	28.98	30.56	32.37	46.85
Electricity Cost Mills/kWh(e)	40.99	41.00	28.50	27.41	28.98	30.56	32.37	46.85
Gasoline Cost								
$/MMBTU	11.98	12.01	8.35	8.03	8.49	9.25	9.48	13.73
$/gal	1.44	1.44	1.00	0.96	1.02	1.11	1.14	1.65
Crude Oil Cost to Refinery $Bbl	45.50	45.50	31.50	30.30	32.20	35.00	36.00	52.20

*Note wherever gasoline is mentioned it also includes diesel fuel
[x] Ref. 13.

Table 8
Cost of Gasoline Co-product from IPFC-FT Plant When the Selling Price of the Electricity Produced is Raised up to Current Cost of 50 Mills/kWh(e) and Total Income to Plant is Maintained

Feedstock Fuel	Natural Gas	Petroleum	N. Dakota Lignite Coal	Wyodak Sub-bituminous Coal	Beluga Alaskan Coal	Kentucky Bituminous Coal	Biomass Wood	IGCC N. Dakota Lignite Coal
Original Total Production Cost (Table 7) Mills/kWh	40.99 ($4/MSCF)	41.00 ($25/Bbl)	28.50	27.41	28.98	30.56	32.37	46.85
Electricity Selling Cost Mills/kWh(e)	50.00	50.00	44.18	40.73	47.27	41.63	50.00	50.00
Gasoline Selling Cost $/gal	1.06	0.91	0.00	0.00	0.00	0.00	0.84	1.24
Crude Oil Cost To Refinery $/Bbl	33.50	28.75	-10.50*	-10.50*	-10.50*	-10.50*	26.50	39.00

* Note at zero $Bbl oil, refining cost is still $4 to $12/Bbl ($0.10 to $0.28/gal). The negative equivalent of crude oil cost is calculated at a cost to refine $0.25/gal to equate IPFC gasoline selling price of zero.

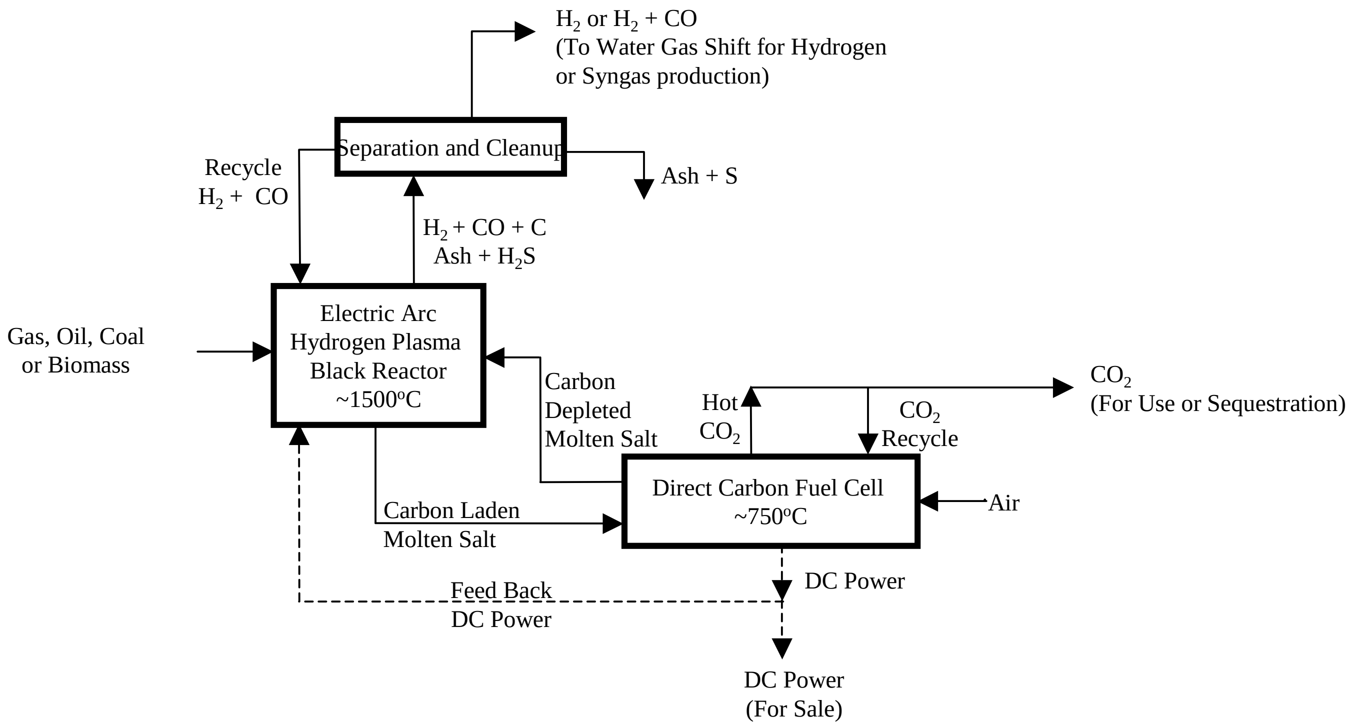

FIG. 1 -- Hydrogen Plasma Black Reactor Integrated with Direct Carbon Fuel Cell for Conversion of Fossil Fuels or Biomass to Electric Power and Hydrogen or Syngas. (IPFC)

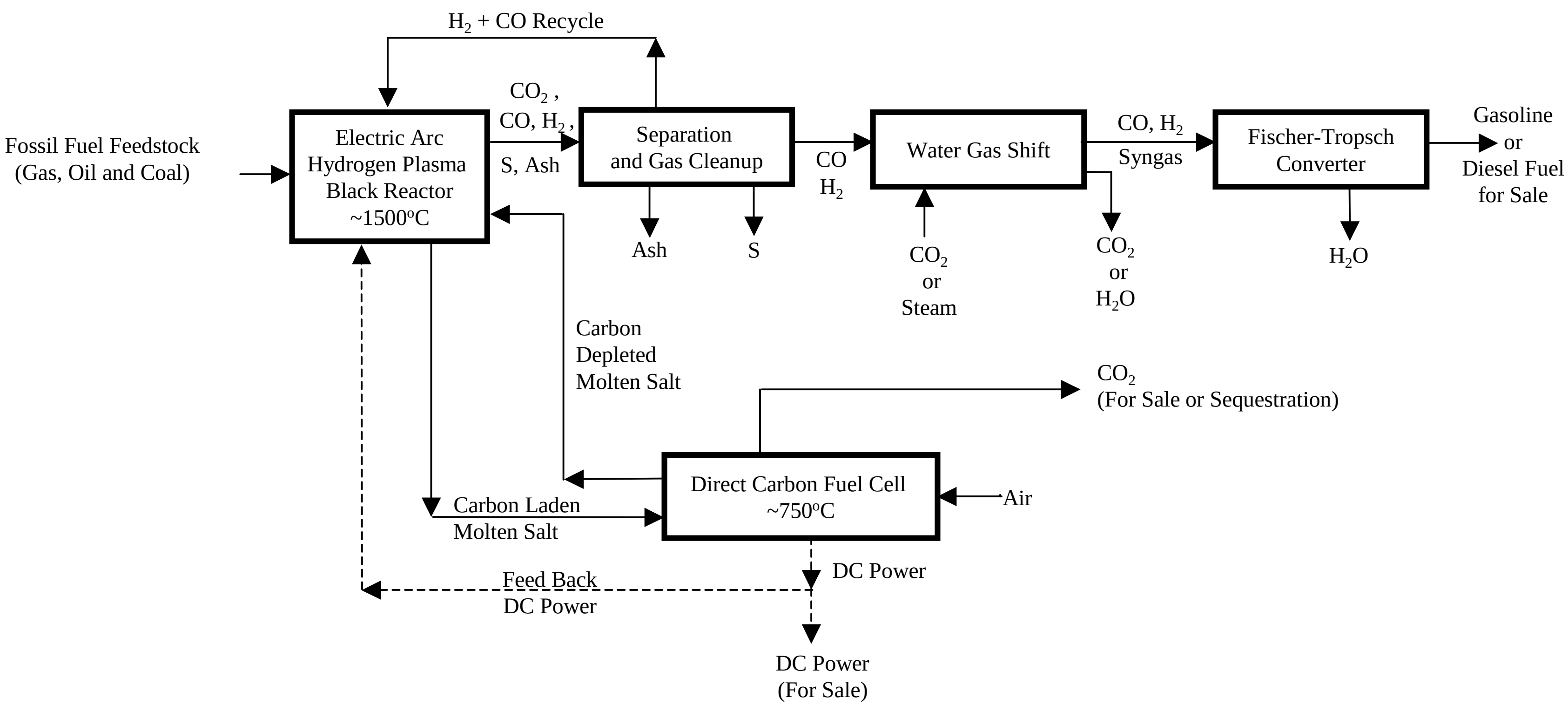

FIG. 2 -- Integrated Plasma Fuel Cell Plant for Producing Power and Transportation Fuels (IPFC – FT).

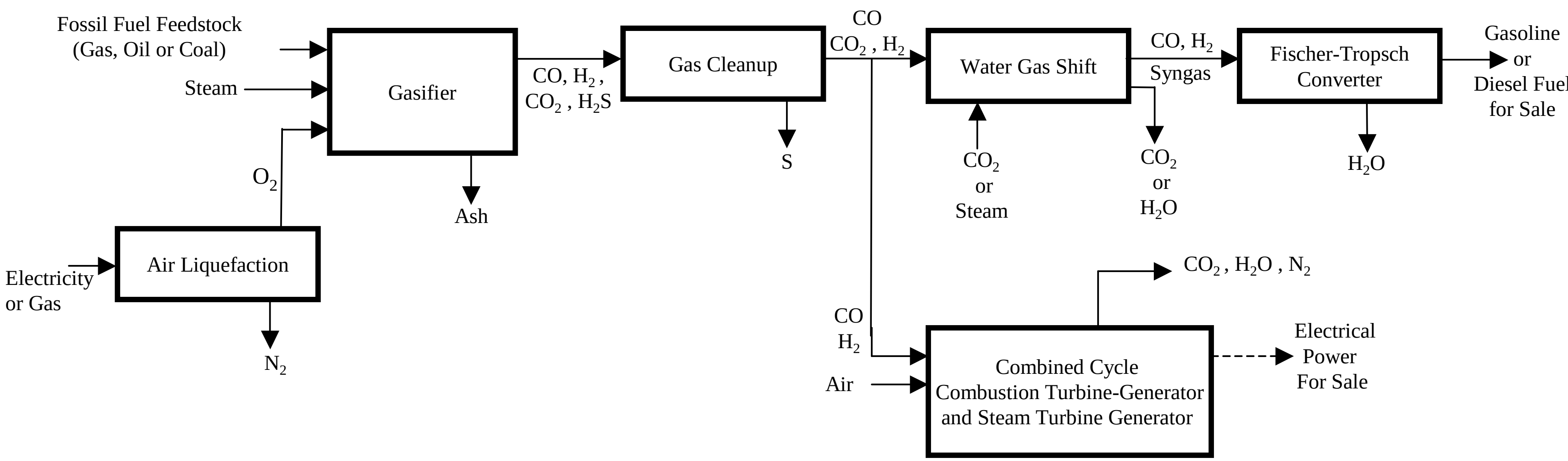

FIG. 3 -- Integrated Gasification Combined Cycle Plant for Producing Power and Transportation Fuels (IGCC – FT).