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HYDROGEN FROM COAL

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Executive Summary:

This report examines current and advanced technologies to produce hydrogen from coal. The performance and economics of these technologies are analyzed including configurations for carbon sequestration. For comparison, the economics of producing hydrogen from natural gas and photovoltaic (PV)/water electrolysis are included.

Ten hydrogen production cases are analyzed in this report. Three of the cases (cases 1 through 3) produce only hydrogen and three (cases 4 through 6) are coproduction cases that co-produce hydrogen and electric power. Cases 7 and 8 use solid oxide fuel cells (SOFC) for electric power production and cases 9 and 10 coproduce hydrogen and power using SOFC technology.

Case 1 is a Texaco quench gasification system with conventional acid gas removal and pressure swing adsorption (PSA) for hydrogen recovery. There is no carbon sequestration in this case. This is a single train 3,000 tons per day (TPD) plant producing 131 MMSCFD of hydrogen. Case 2 is similar to Case 1 except that all of the carbon dioxide is removed prior to the PSA unit. It is then assumed that this concentrated and compressed stream of carbon dioxide can be sequestered for an additional cost of \$10 per ton of carbon.

The configuration for Case 3 uses advanced E-gas gasification with hot gas cleanup in combination with a ceramic membrane system operating at about 600 degrees Centigrade that is capable of shifting and separating hydrogen from the clean synthesis gas. If it is assumed that the cost of the ceramic membrane system is equal to the combined cost of an equivalent conventional amine and PSA system, the RSP of the hydrogen is estimated to be \$5.89/MMBtu. In Case 4, two trains of advanced entrained gasification are used and the coal feed is 6,000 TPD. One train makes synthesis gas to feed the PSA unit for hydrogen production and the other train makes synthesis gas to feed a combined cycle power plant. Case 5 is similar to Case 4 except that all the synthesis gas is shifted and after cooling and shift the carbon dioxide is removed in a bulk carbon dioxide removal system for sequestration. Case 6 is similar to Case 3 except that two trains of gasification are used that process 6000 TPD of coal to provide synthesis gas to the 600 degrees C ceramic membrane separation device.

Tables ES 1 and ES 2 summarize the results of this analysis for hydrogen from coal and for coproduction of hydrogen and power.

Table ES 1: Summary of Hydrogen from Coal Cases.

	CASE 1	CASE 2	CASE 3
Carbon Sequestration	NO	YES (87%)	YES (100%)
Hydrogen MMSCFD	131	119	158
Coal T/D (AR)	3000	3000	3000
Efficiency (%HHV)	63.7	59	75.5
XS Power MW	20.4	26.9	25
Power Value (MILS/kWh)	35.6	53.6	53.6
Capital \$MM	367	417	425
RSP of Hydrogen \$/MMBTU	6.83	8.18	5.89

Table ES 2: Summary of Coproduction Cases.

	CASE 4	CASE 5	CASE 6
Carbon Sequestration	NO	YES (95%)	YES (100%)
Hydrogen MMSCFD	149	153	153
Coal T/D (AR)	6000	6000	6000
Efficiency (%HHV)	62.4	56.5	59
XS Power MW	475	358	416
Power Value (MILS)	35.6	53.6	53.6
Capital \$MM	910	950	950
RSP of Hydrogen \$/MMBTU	5.42	5.64	3.98

Table ES 3: Summary of Cases using SOFC Systems.

	CASE 7	CASE 8	CASE 9	CASE 10
CARBON SEQUESTRATION	NO	YES (98%)	YES (90%)	YES (95%)
HYDROGEN MMSCFD	0	0	149	150
COAL T/D (AR)	3000	3000	6000	6000
EFFICIENCY (%HHV)	65.7	61.3	64.5	65.2
XS POWER MW	567	529	509	519
POWER VALUE (MILS)	33.7	41.0	53.6	53.6
CAPITAL \$MM	628	717	1,037	1,019
RSP OF HYDROGEN \$/MMBTU	NA	NA	2.79	2.40

Table ES 3 summarizes the results for solid oxide fuel cell (SOFC) configurations. Cases 7 and 8 are baseline SOFC configurations that only produce electric power. Case 9 is a two-gasification train (6000 TPD of coal) carbon sequestered coproduction case where a SOFC topping cycle configuration is used in combination with a PSA system for hydrogen separation. Case 10 is a two gasification train (6000 TPD of coal) coproduction case where a SOFC topping cycle configuration is used in combination with a ceramic membrane system for hydrogen separation.

Hydrogen can be produced from coal with current gasification technology at about 64 percent efficiency (HHV basis) for a cost of production in the range \$6.50 to \$7.00 per MMBtu. The need to sequester carbon dioxide from such a facility would raise this production cost to just over \$8.00/MMBtu and decrease efficiency to about 59 percent. Advanced gasification technology and membrane separation has the potential to reduce the cost of production of hydrogen with carbon sequestration to less than \$6.00/MMBtu and increase the efficiency of production to about 75 percent. Additional R&D and performance demonstration is necessary to verify this.

If hydrogen is produced in an advanced gasification coproduction facility that also generates electric power the production costs of the coproduced hydrogen can be reduced depending on the value of the power. If the coproduced electric power is valued at \$35.6/MWH (the cost of producing power from a natural gas combined cycle plant (NGCC)) hydrogen can be produced for about \$5.50/MMBtu. If the carbon dioxide is sequestered in this coproduction facility, the cost of hydrogen is only slightly increased if it is assumed that the coproduced power is valued at \$53.6/MWH (the cost of producing

power from a sequestered natural gas combined cycle (NGCC) plant). Utilization of advanced membrane separation technology has the potential to reduce hydrogen production costs to about \$4.00/MMBtu.

The greatest potential for reducing the production cost of hydrogen from coal is in configurations that include solid oxide fuel cells (SOFC). Coproduction facilities that use SOFC topping cycles to produce electric power and hydrogen have the potential to reduce the production cost of hydrogen to the range \$2.50 to \$3.00 per MMBtu. These costs could be achieved in facilities that sequester carbon dioxide at efficiencies around 65 percent. Clearly such potential warrants continuing RD&D in such integrated facilities that include advanced coal gasification, SOFC topping cycles, and advanced membrane separation technologies.

Costs of producing hydrogen from traditional steam methane reforming of natural gas are of course dependent on fuel costs. If natural gas is \$3.00/MMSCF then the resulting cost of hydrogen is \$4.80/MMBtu. Sustainable production of hydrogen from renewable sources like sunlight using photovoltaic (PV) water electrolysis could be a future goal. Continuing RD&D to significantly reduce the costs of PV systems is necessary for hydrogen production costs to be in the same range as production from coal. PV costs of about \$300 per peak kilowatt will be necessary to bring hydrogen production costs to the range \$7.00 to \$8.00 per MMBtu.

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HYDROGEN FROM COAL

Introduction:

Large quantities of hydrogen are currently used worldwide in the petroleum refining industry to desulfurize and upgrade crude oil and in the manufacture of ammonia for fertilizers. Hydrogen for these applications is produced predominantly by steam reforming of natural gas and as a byproduct from naphtha reforming. Some hydrogen is also produced from coal gasification, coke oven gas, and electrolysis of water. Concerns over global climate change and eventual resource depletion of fossil fuel resources have revived the concept of the hydrogen economy where hydrogen is used as an energy carrier. This concept would use hydrogen to provide energy to all sectors including central generating electric power, distributed power, industrial, residential, and transportation. Eventually the hydrogen would be produced from water using energy derived from sustainable resources, for example nuclear fusion and photovoltaics. Combustion of the hydrogen or electrochemical conversion via fuel cell technology would produce water, thus completing the cycle. In the shorter term, the hydrogen could be produced from fossil resources including natural gas, coal, petroleum coke etc. The use of fossil carbon as a reductant and the conversion inefficiencies associated with hydrogen production from these resources would result in the production of large quantities of carbon dioxide. With the continued concern over climate change this carbon dioxide would have to be sequestered.

This report examines current and advanced technologies to produce hydrogen from coal. The performance and economics of these technologies are analyzed including configurations for carbon sequestration. For comparison, the economics of producing hydrogen from natural gas and photovoltaic (PV)/water electrolysis are included.

Cases Analyzed:

The following ten hydrogen production cases are analyzed in this report. Three of the cases produce only hydrogen and three cases are coproduction cases that co-produce hydrogen and electric power. Cases 7 and 8 use solid oxide fuel cells (SOFC) for electric power production and cases 9 and 10 coproduce hydrogen and power using SOFC technology.

- Case 1: Hydrogen production from coal using Texaco quench gasification, conventional cold gas cleaning, water-gas shift, and pressure swing adsorption with no carbon dioxide sequestration.
- Case 2: same as Case 1 but with carbon dioxide sequestration.
- Case 3: Hydrogen production from coal using advanced gasification, advanced membrane technology for carbon dioxide removal and hydrogen separation, and with carbon dioxide sequestration.

- Case 4: Coproduction of hydrogen and electric power using advanced gasification technology with no carbon dioxide sequestration.
- Case 5: same as Case 4 with carbon dioxide sequestration.
- Case 6: same as Case 5 but using an advanced membrane separation system.
- Case 7: baseline solid oxide fuel cell (SOFC) for power generation with no carbon sequestration.
- Case 8: solid oxide fuel cell (SOFC) for power generation with carbon sequestration.
- Case 9: solid oxide fuel cell (SOFC) for power and hydrogen production with carbon sequestration.
- Case 10: solid oxide fuel cell (SOFC) for power and hydrogen production using an advanced membrane separation system with carbon sequestration.
- For comparison purposes, the cost of hydrogen produced from natural gas using conventional steam methane reforming (SMR) and hydrogen produced from photovoltaic/water electrolysis are included.

Results:

Table 1 summarizes the results of the analysis for the three coal-derived hydrogen cases.

Table 1: Summary of Hydrogen from Coal Cases.

	CASE 1	CASE 2	CASE 3
Carbon Sequestration	NO	YES (87%)	YES (100%)
Hydrogen MMSCFD	131	119	158
Coal T/D (AR)	3000	3000	3000
Efficiency (%HHV)	63.7	59	75.5
XS Power MW	20.4	26.9	25
PowerValue (MILS/kWh)	35.6	53.6	53.6
Capital \$MM	367	417	425
RSP of Hydrogen \$/MMBTU	6.83	8.18	5.89

Notes:

1) Coal cost is \$29/ton (and is assumed to de-escalate at 1.5 percent below general inflation) and the assumed plant capacity factor is 85 percent.

- 2) For those cases with no sequestration, the coproduced power value is assumed to be \$35.6/MWh based on the cost of power production from Natural Gas Combined Cycle (NGCC) plants if natural gas costs \$3.75/MMBtu. In cases where there is carbon sequestration, the coproduced power is assumed to have a value of \$53.6/MWh based on an additional cost of power production from Natural Gas Combined Cycle (NGCC) plants with sequestration of 18 mills/kWh (reference EPRI report 1000316).
- 3) For cases with sequestration it is assumed that \$10 per ton of carbon is added for sequestration after the concentrated carbon dioxide stream has been isolated, and the carbon dioxide stream is compressed to 200 bars.
- 4) For Case 3, the membrane configuration assumed is that used in the Parsons study (Case 6) reference “Hydrogen Plant Cost Comparisons” letter report Sept 2000.

Case 1 represents a Texaco quench gasification system with conventional acid gas removal and PSA for hydrogen recovery. This is shown schematically in Figure 1. There is no carbon sequestration in this case. About half of the carbon dioxide is removed prior to the PSA unit to produce a combustible tail gas stream. This is a single train 3,000 tons per day (TPD) plant producing 131 MMSCFD of hydrogen. The tail gas from the PSA unit is used to superheat steam for plant power production. Excess electric power (20.4 MW) is sold. The capital cost for this single train gasification facility is estimated to be \$367 million. The financial parameters used to calculate the required selling price (RSP) of hydrogen are shown in Table 2. The RSP of the hydrogen from this facility is estimated to be \$6.83/MMBtu.

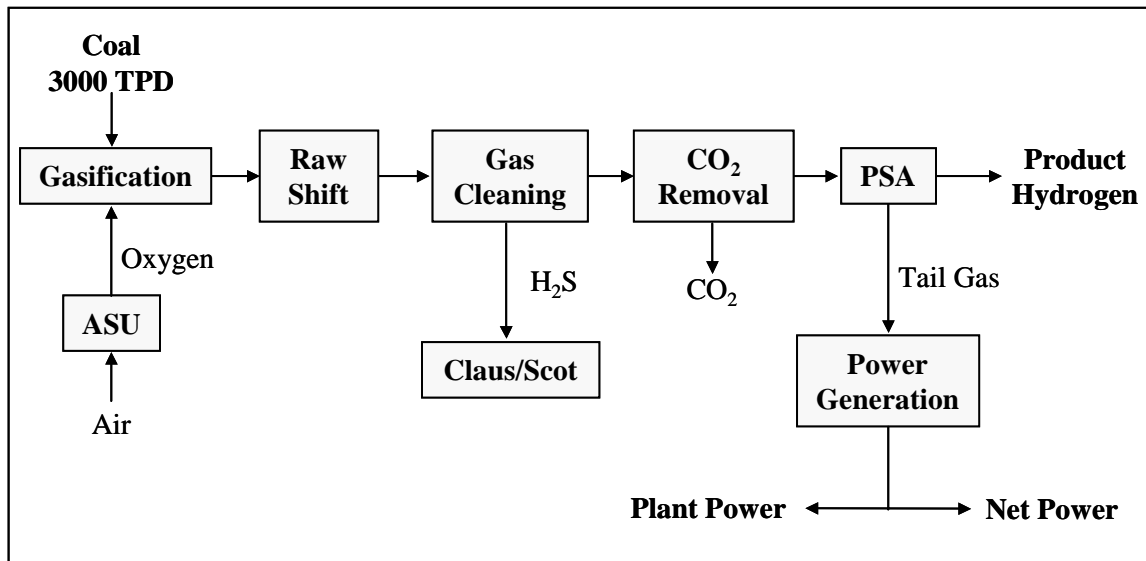


Figure 1: Cases 1 and 2: Hydrogen from Coal

Table 2: Financial Assumptions

- 25 YEAR PLANT LIFE
- 67/33 % DEBT/EQUITY FINANCING
- 15 % RETURN ON EQUITY
- 8 % INTEREST, 16 YEAR TERM
- 3 % INFLATION (coal de-escalation of 1.5 % per annum below general inflation)
- 16 YEAR DDB DEPRECIATION
- 40 % COMBINED FEDERAL AND STATE TAX RATE
- 3 YEAR CONSTRUCTION, 50 % OUTPUT IN START-UP YEAR
- SEQUESTRATION OF HIGH PRESSURE CO₂ STREAM COSTS \$10/TON CARBON

Case 2 is similar to Case 1 (see Figure 1) except that all of the carbon dioxide is removed prior to the PSA unit. This is compressed to 200 bar and is assumed to be sequestered. It is then assumed that this concentrated and compressed stream of carbon dioxide can be sequestered for an additional cost of \$10 per ton of carbon. In this configuration 87 percent of the feed carbon is sequestered. Hydrogen production is 119 MMSCFD and 27 MW of excess power is produced. Capital cost is estimated to be \$417 million. The RSP of hydrogen is estimated to be \$8.18/MMBtu.

The configuration for Case 3 is shown in Figure 2. This is taken from the Parsons Letter Report “Hydrogen Plant Cost Comparisons” of September 2000. In this configuration, advanced E-gas gasification with hot gas cleanup is used in combination with a ceramic membrane system operating at about 600 degrees Centigrade that is capable of shifting and separating hydrogen from the clean synthesis gas. It is assumed that 90 mole percent of the synthesis gas is converted to hydrogen in this membrane system. This membrane system is assumed to be similar to the K25 system under development at ORNL. The hydrogen (158 MMSCFD) is separated at low pressure (it is assumed that a 100 psi pressure drop across the membrane is necessary) and must be compressed as shown. The remaining synthesis gas containing mostly carbon dioxide but with some carbon monoxide and hydrogen is combusted with oxygen in a gas turbine to provide power for the plant. Oxygen is used so that a concentrated stream of carbon dioxide is produced for sequestration in this case. Heat is recovered from both the gas turbine exit gas and from the hot hydrogen in HRSGs where the steam produced is sent to a steam turbine for more power generation. Excess power (25 MW) is sold. Capital cost for this facility is estimated to be \$425 million. If it is assumed that the cost of the ceramic membrane system is equal to the combined cost of an equivalent conventional amine and PSA system, the RSP of the hydrogen is estimated to be \$5.89/MMBtu.

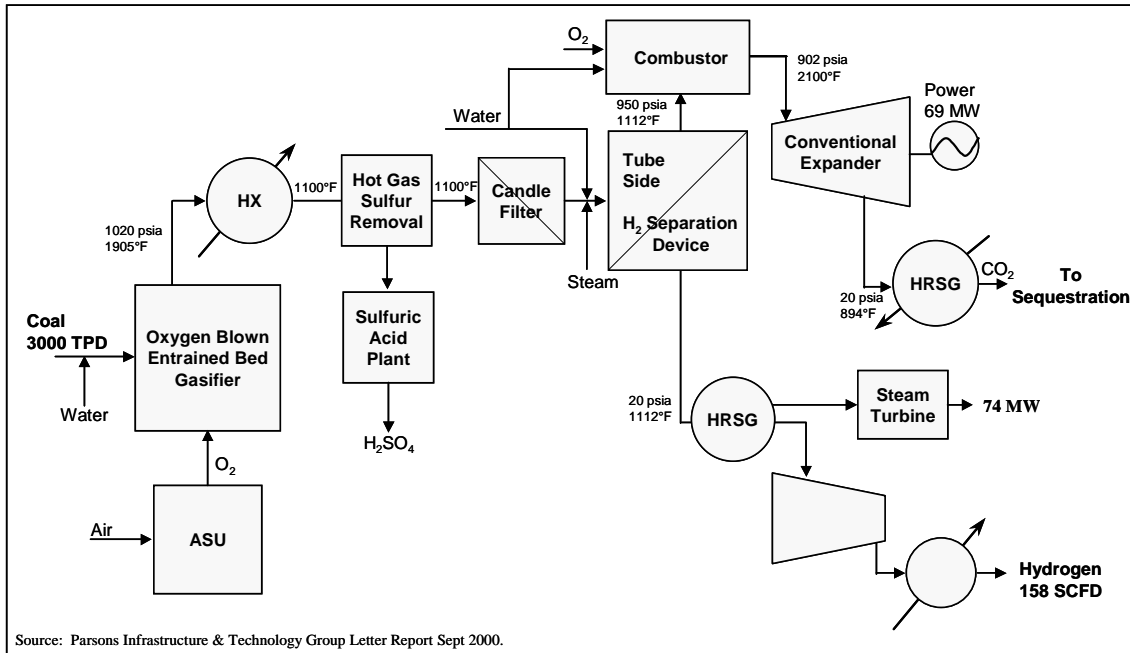


Figure 2: Case 3: Hydrogen from Coal using Membrane Separation (Sequestration)

Table 3: Summary of Coproduction Cases.

	CASE 4	CASE 5	CASE 6
Carbon Sequestration	NO	YES (95%)	YES (100%)
Hydrogen MMSCFD	149	153	153
Coal T/D (AR)	6000	6000	6000
Efficiency (%HHV)	62.4	56.5	59
XS Power MW	475	358	416
Power Value (MILS)	35.6	53.6	53.6
Capital \$MM	910	950	950
RSP of Hydrogen \$/MMBTU	5.42	5.64	3.98

Table 3 summarizes the results of the Mitretek analysis of cases 4 through 6 that coproduce hydrogen and electric power.

In Case 4, (Figure 3) two trains of advanced entrained gasification are used and the coal feed is 6,000 TPD. One train makes synthesis gas to feed the PSA unit for hydrogen production and the other train makes synthesis gas to feed a combined cycle power plant. PSA tail gas is compressed and fed to the gas turbine. There is no sequestration in this case. Total power generated in the combined cycle unit is 592 MW (356 MW from the gas turbine and 236 from the steam turbine) and parasitic power required is 117 MW leaving a net power production of 475 MW. Hydrogen production is 149 MMSCFD. Capital cost is estimated to be \$910 million and the RSP of the hydrogen is estimated to be \$5.42/MMBtu if the coproduced power can be sold for 35.6 mills.

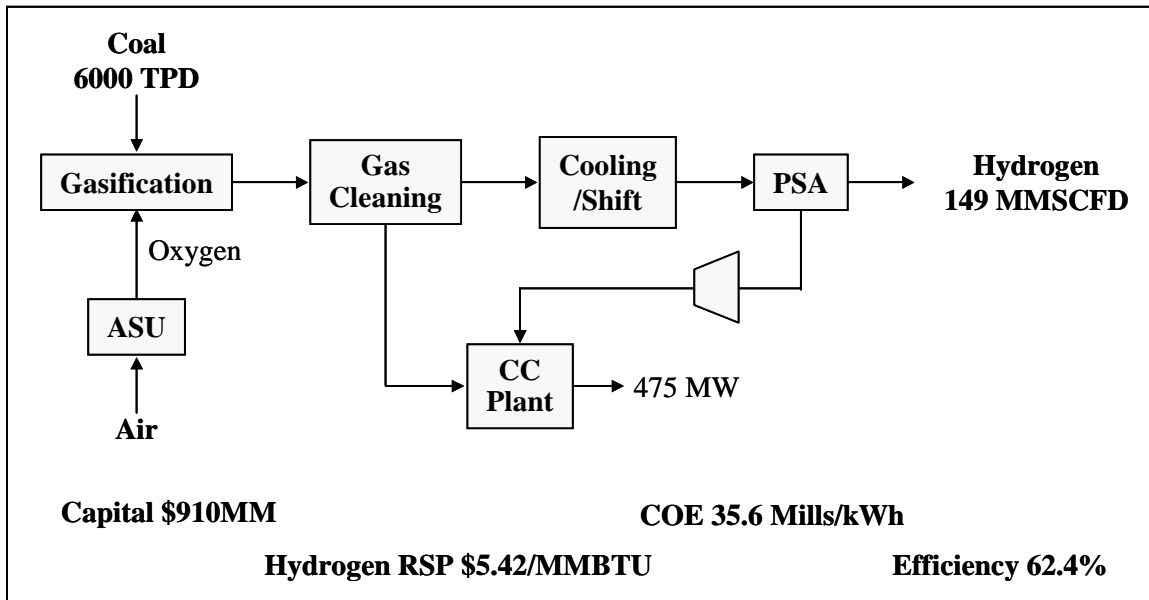


Figure 3: Case 4: Coal to Hydrogen and Power

Case 5 (Figure 4) is similar to Case 4 except that all the synthesis gas is shifted and after cooling and shift the carbon dioxide is removed in a bulk carbon dioxide removal system for sequestration. The synthesis gas with the carbon dioxide removed is sent to the PSA units where 153 MMSCFD of pure hydrogen is recovered. The PSA tail gas is compressed and sent to the combined cycle (CC) plant for power production. The gas turbine produces 302 MW and the steam turbine 182 MW for a total power production of 484 MW. Parasitic power used is 126 MW including the power needed for carbon dioxide compression. Net power for sales is 358 MW. Capital cost is estimated to be \$950 million for this coproduction facility and the RSP of the coproduced hydrogen is estimated to be \$5.64/MMBtu if the coproduced power can be sold for 53.6 mills per kWh. If the value of the coproduced electricity is the cost of producing it from an advanced IGCC facility with sequestration (that is 46.3 mills/kWh, see Appendix A) the resulting RSP of the coproduced hydrogen is \$6.89/MMBtu.

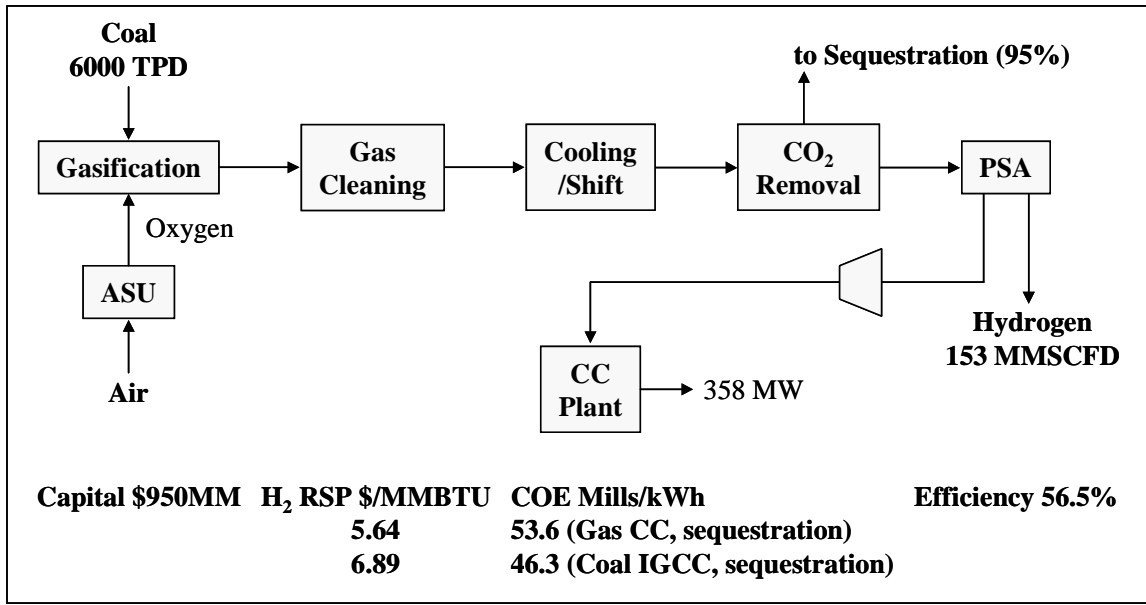


Figure 4: Case 5: Coal to Hydrogen and Power (Sequestration)

Case 6 (Figure 5) is similar to Case 3 except that two trains of gasification are used that process 6000 TPD of coal to provide synthesis gas to the 600 degrees C ceramic membrane separation device. The product hydrogen is split into two streams. One becomes the hydrogen product (153 MMSCFD) and the other is sent to a hydrogen-fired gas turbine combined cycle system to produce 150 MW of electric power. The non-permeate stream from the ceramic membrane consisting essentially of carbon monoxide, hydrogen, and carbon dioxide is combusted with oxygen in a gas turbine to produce 260 MW of additional power. The hot effluent gases from the gas turbine and the hydrogen turbine are sent to HRSGs for steam generation. Power produced in the steam turbine is 209 MW. Total power production is 619 MW and parasitic power needed is 202 MW leaving net power for sales of 417 MW. The carbon dioxide produced by combustion of the non-permeate steam is sequestered. Capital cost is estimated to be \$950 million for this plant, and the RSP of the hydrogen is estimated to \$3.98/MMBtu if power is sold for 53.6 mills.

Table 4 summarizes the results of the Mitretek analysis of cases 7 through 10 that use solid oxide fuel cells (SOFC) for production of electric power and for coproduction of power and hydrogen.

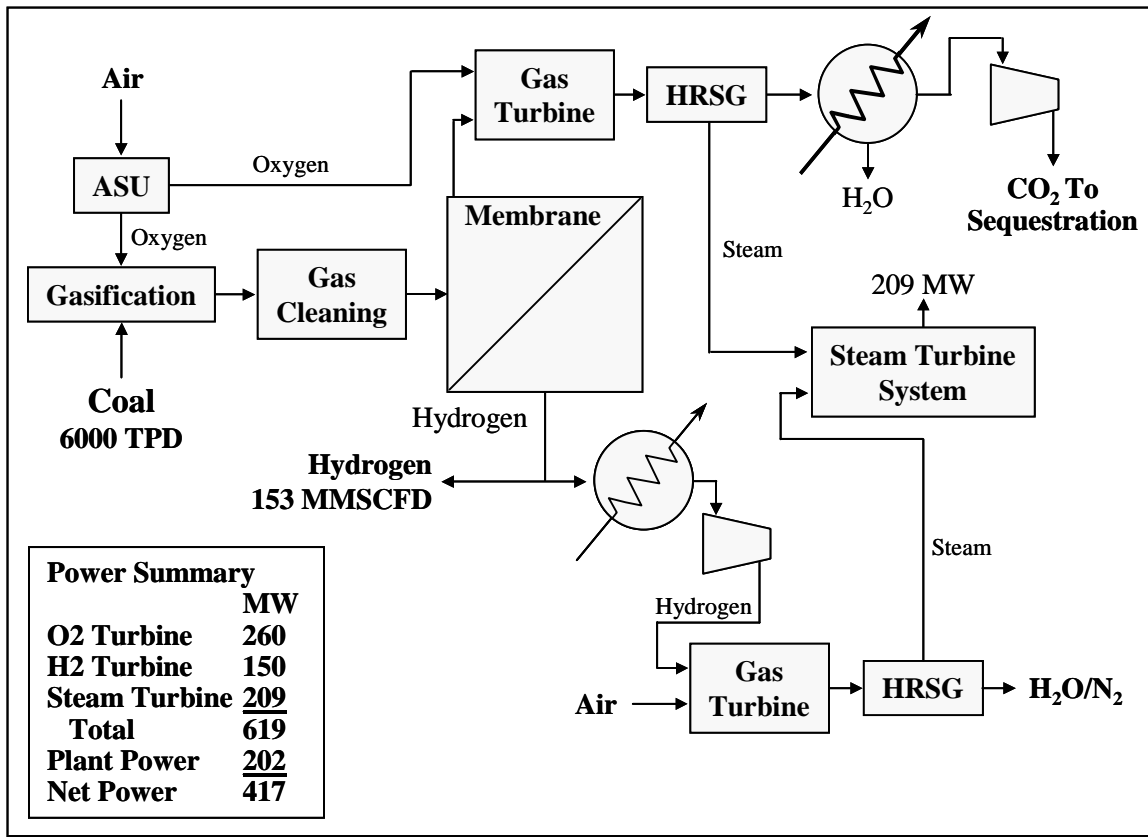


Figure 5: Case 6: Coproduction of Hydrogen and Power using a 600°C Hydrogen Membrane Separation System

Before discussing the coproduction results with the SOFC configuration, the baseline SOFC plant for production of electric power only is summarized in Table 4 (Case 7) and Figure 6. This is a single train (3000 TPD of coal), no sequestration coal gasification configuration where the clean synthesis gas from coal is sent to the anode of the SOFC stack. Air is sent to the cathode of the SOFC. The SOFC is assumed to operate at a temperature of 2000 degrees F, have an efficiency of 60 percent (HHV) and convert 85 percent of the synthesis gas. The SOFC is used here as a topping cycle and produces 358 MW of power. The hot exit gases from the SOFC at about 2000 degrees F are set to the gas turbine combustor that produces 179 MW of power. The gas turbine exit gases are sent to the HRSG where the steam generated is used in the steam turbine of the combined cycle bottoming cycle to produce an additional 87 MW of power. Total gross power produced is 624 MW of which 57 MW is used for plant power. Net power output is thus 567 MW and overall plant efficiency is an impressive 65.7 percent (HHV). Total capital for this facility is estimated to be \$628 million. The capital cost of the SOFC stack was assumed to be \$400/kW. The resulting cost of electricity (COE) is calculated to be 33.7 mills per kWh.

Table 4: Summary of Cases using SOFC Systems.

	CASE 7	CASE 8	CASE 9	CASE 10
CARBON SEQUESTRATION	NO	YES (98%)	YES (90%)	YES (95%)
HYDROGEN MMSCFD	0	0	149	150
COAL T/D (AR)	3000	3000	6000	6000
EFFICIENCY (%HHV)	65.7	61.3	64.5	65.2
XS POWER MW	567	529	509	519
POWER VALUE (MILS)	33.7	41.0	53.6	53.6
CAPITAL \$MM	628	717	1,037	1,019
RSP OF HYDROGEN \$/MMBTU	NA	NA	2.79	2.40

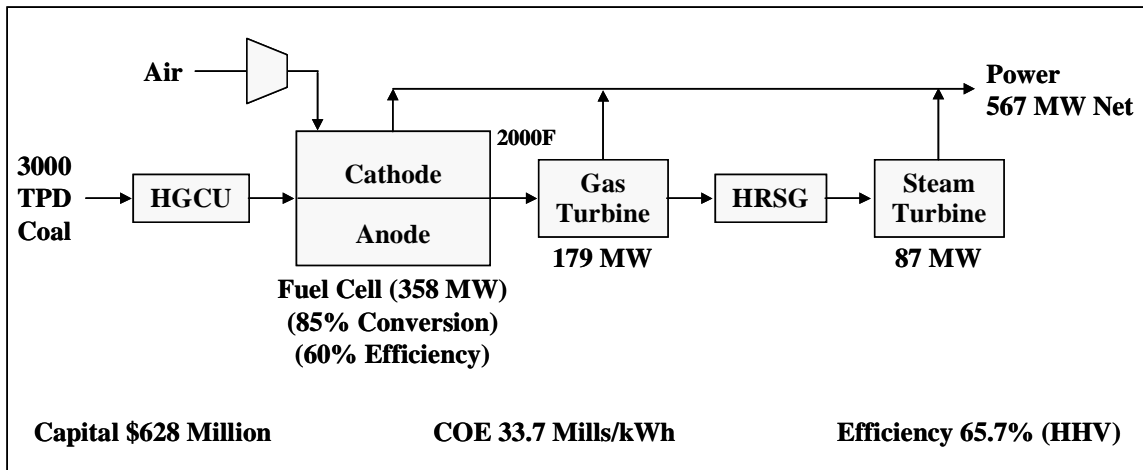


Figure 6: Case 7: SOFC Topping Cycle for Power

Case 8 (Figure 7) is a SOFC topping cycle case for power generation with carbon sequestration. This is similar to Case 7 except that the exit gas from the anode of the SOFC is cooled and shifted and the carbon dioxide is removed before being recombined with the hot cathode gas and combusted in the gas turbine combustor. In this case about 98 percent carbon sequestration is achieved. The SOFC produces 358 MW of power and the gas turbine produces 86 MW. The gas turbine exit gases are sent to the HRSG where the steam generated is used in the steam turbine of the combined cycle bottoming cycle to produce an additional 146 MW of power. Total gross power produced is 590 MW of

which 61 MW is used for plant power. Net power output is thus 529 MW and overall plant efficiency is 61.3 percent (HHV). Total capital for this facility is estimated to be \$717 million. The resulting cost of electricity (COE) is calculated to be 41.0 mills per kWh.

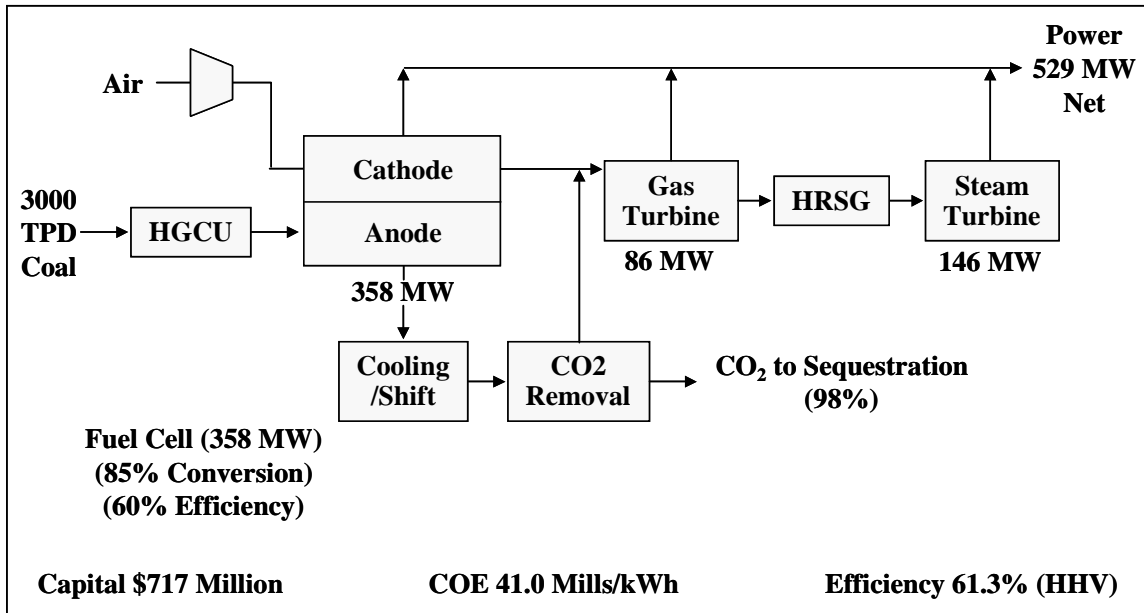


Figure 7: Case 8: SOFC Topping Cycle for Power (Sequestration)

Case 9 (Figure 8) is a two-gasification train (6000 TPD of coal) carbon sequestered coproduction case where a SOFC topping cycle configuration is used in combination with a PSA system for hydrogen separation. The clean synthesis gas stream is split with one portion being sent to the anode of the SOFC where 358 MW of power is produced and the other to a shift reactor. The anode effluent gas is also sent to the shift reactor. The shifted gas is sent to bulk carbon dioxide removal. The carbon dioxide free synthesis gas is sent to the PSA units where 149 MMSCFD of hydrogen is recovered. The PSA tail gas is compressed and combusted in the gas turbine together with the hot cathode gas to produce 151 MW of power. The gas turbine effluent is sent to the HRSG where the steam generated is used in the steam turbine of the combined cycle bottoming cycle to produce an additional 118 MW of power. Total gross power produced is 629 MW of which 120 MW is used for plant power. Net power output is thus 509 MW and overall plant efficiency is 64.5 percent (HHV). About 90 percent carbon sequestration is achieved in this case. Total capital for this facility is estimated to be \$1,037 million. The RSP of the hydrogen is \$2.79/MMBtu if the coproduced electricity can be sold for 53.6 mills per kWh. If the electricity value is the cost of producing the power from an SOFC facility with sequestration (that is 41 mills per kWh) the resulting RSP of the coproduced hydrogen is \$5.93/MMBtu. If the value of the coproduced electricity is the cost of producing it from an advanced IGCC facility with sequestration (that is 46.3 mills per kWh see Appendix A) the resulting RSP of the coproduced hydrogen is \$4.61/MMBtu.

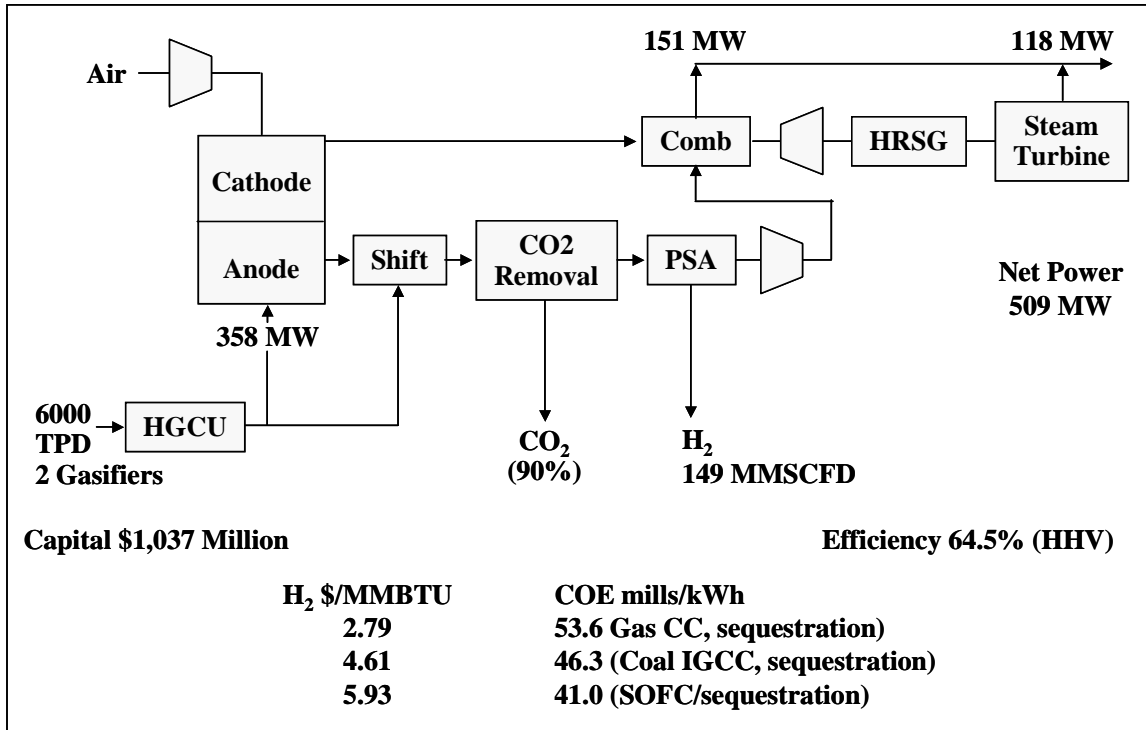


Figure 8: Case 9: SOFC for Power and Hydrogen (Sequestration)

Case 10 (Figure 9) is a two gasification train (6000 TPD of coal) coproduction case where a SOFC topping cycle configuration is used in combination with a ceramic membrane system for hydrogen separation. The clean synthesis gas stream is sent to the ceramic membrane system where the non-permeate stream consisting of carbon monoxide, hydrogen, and carbon dioxide is sent to the anode of the SOFC where 404 MW of power is produced. The permeate stream consisting of pure hydrogen at about 1100 degrees F is sent to a HRSG to recover heat as steam and then compressed to give the hydrogen product. The hot anode effluent gas is sent to the combustor of the gas turbine where it is burned with oxygen to produce 222 MW of power. The gas turbine effluent is sent to a HRSG for steam generation. The effluent flue gas from this HRSG contains only carbon dioxide and water and is compressed to 200 bars for sequestration. The hot cathode gas is sent to a turbine to produce 151 MW of power and then to a HRSG for steam generation. Steam from the two HRSGs produces 101 MW of power. Total gross power produced is therefore 879 MW. Plant power parasitic requirements are: ASU 109 MW, carbon dioxide compression 68 MW, hydrogen compression 8 MW, and SOFC air compression 175 MW for a total of 359 MW. Net power output is thus 519 MW and overall plant efficiency is 65.2 percent (HHV). Total capital for this facility is estimated to be \$1,019 million. The RSP of the hydrogen is \$2.40/MMBtu if the coproduced electricity can be sold for 53.6 mills per kWh. If the electricity value is the cost of producing the power from an SOFC facility with sequestration (that is 41 mills per kWh) the resulting RSP of the coproduced hydrogen is \$5.58/MMBtu. If the value of the coproduced electricity is the cost of producing it from an advanced IGCC facility with

sequestration (that is 46.3 mills per kWh see Appendix A) the resulting RSP of the coproduced hydrogen is \$4.24/MMBtu.

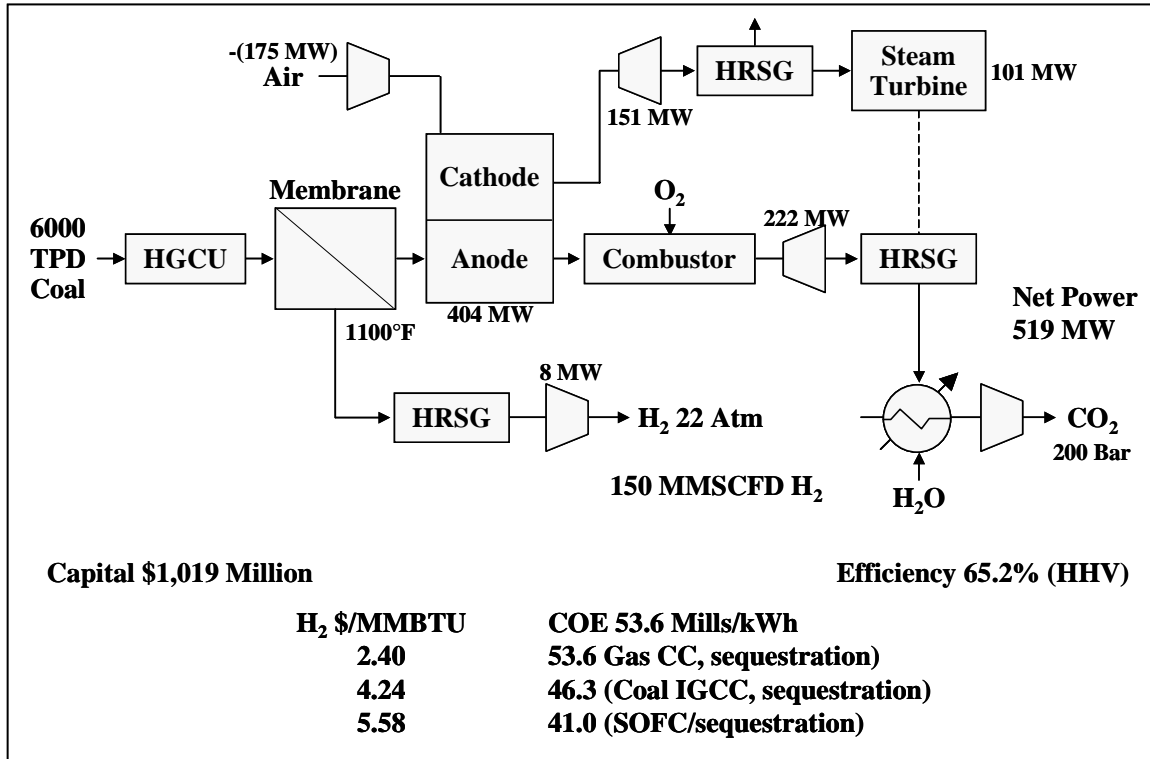


Figure 9: Case 10: SOFC Power/H₂/Membrane (Sequestration)

Appendix B gives details of capital and operating costs for all of the 10 cases described above.

Comparison with Costs of Hydrogen from Natural Gas Plants:

Hydrogen is typically produced from natural gas at refineries by steam methane reforming (SMR). This is a mature technology and the cost of the produced hydrogen is sensitive to the natural gas feedstock cost. Such a relationship is shown in Figure 10 where the resulting cost of hydrogen is plotted against the natural gas feedstock price. The relationship follows the equation:

$$\text{Hydrogen cost (\$/MMBtu)} = 1.27 * \text{NG price (\$/MMBtu)} + 0.985$$

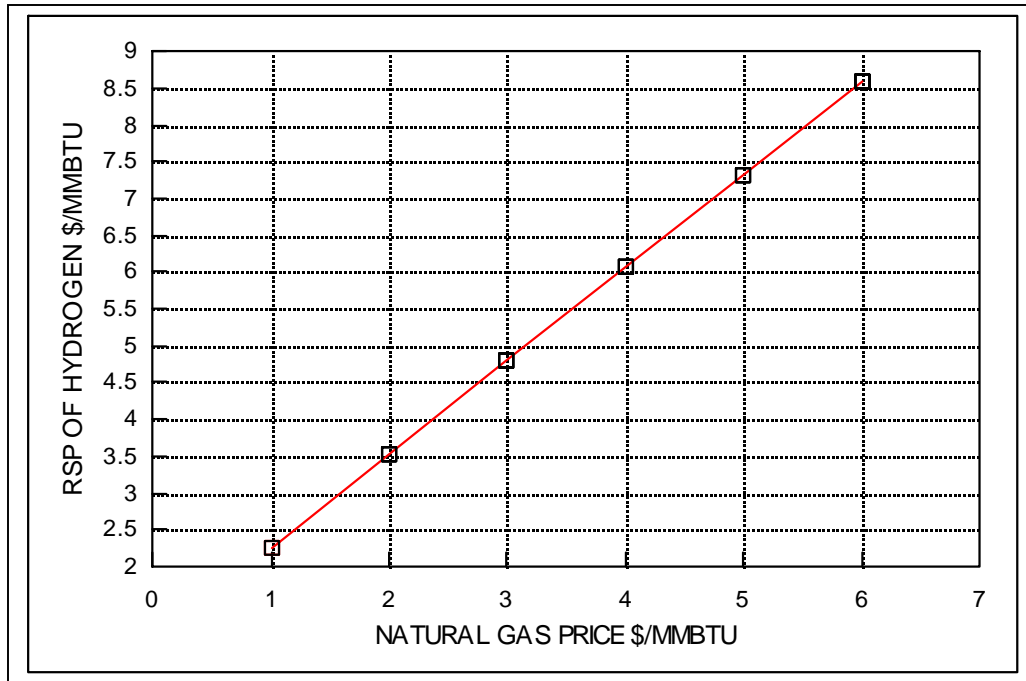


Figure 10: Cost of Hydrogen from Steam Methane Reforming

Capital cost of a large SMR facility (100 MMSCFD) is typically in the range \$0.65-\$ 0.8 per SCFD of hydrogen. Efficiencies are typically in excess of 70 percent HHV.

If the capital cost of the plant is \$0.70/SCFD and natural gas is \$3.00/MMSCF then the resulting cost of hydrogen is \$4.80/MMBtu. This cost is about 12 percent lower than cases 4 and 5 above where coal is used in coproduction configurations with and without carbon sequestration.

Comparison with Costs of Hydrogen from Photovoltaic (PV) Water Electrolysis Plants:

In the future, hydrogen could be produced by water electrolysis using photovoltaics. Table 5 summarizes the assumptions for a generic photovoltaic water electrolysis system in an area with an average insolation of 275 watts per square meter. The table shows a case where the photovoltaic efficiency is 18 percent, and the electrolysis efficiency is 85 percent. If the total cost of the photovoltaic system is \$300 per peak kilowatt and the electrolysis cost is \$231 per peak kilowatt, the resulting cost of hydrogen is \$7.32 per MMBtu. This assumes an oxygen byproduct credit of \$18 per ton. Figure 11 shows how the production cost of hydrogen varies with the total cost of the PV system. Current PV costs are probably in the range \$1200-2400 per peak kilowatt which would put the production cost of hydrogen in the range of \$24-45/MMBtu.

Table 5: Photovoltaic Hydrogen

INSOLATION	275	WATTS/SM
PVEFF	0.18	
PV COST	300	PERKWP
ELECTROLYSER	231	PERKW
ELEC EFF	0.85	
CRF	0.127	
O&M	0.01	
HYDROGEN	325	BTU/CF
HYDROGEN	0.0053	LB/CF
HYDROGEN	61095	BTU/LBHHV
PLANT SIZE	150	MMSCFDH2
PVCAPACITY	0.33	
PLANT CAPACITY	0.9	
IKWH	3412.14	BTU
MWHR/TONH2	42.12985	
ANNUALPOWERREQD	5,501,263	MWHS
PV REQUIRED	2114.472	MW
PV AREA	10555.49	ACRES
PVCOST/SQM	14.85316	
PVCAPITAL	634.3415	
BOSCAP	0	PVCAPITAL \$/SQM
BOSCAP		\$80.56
		BOSCAP \$0.00
		ELECTROLYSER \$62.03
		O&M (\$7.27)
		TOTAL \$116.83
		\$/TON \$894.73
		HYDROGEN \$/MMBTU \$7.32

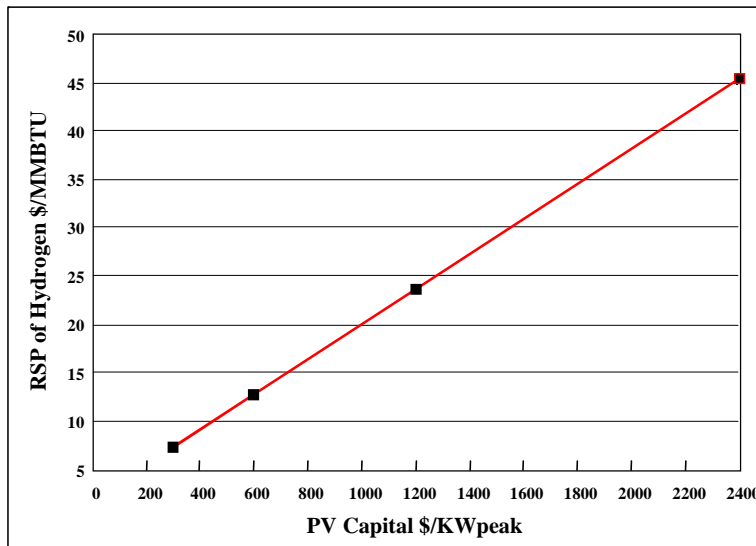


Figure 11: Cost of Hydrogen from Photovoltaic Water Electrolysis

Conclusions:

Hydrogen can be produced from coal with current gasification technology at about 64 percent efficiency (HHV basis) for a cost of production in the range \$6.50 to \$7.00 per MMBtu. The need to sequester carbon dioxide from such a facility would raise this production cost to just over \$8.00/MMBtu and decrease efficiency to about 59 percent. Advanced gasification technology and membrane separation has the potential to reduce the cost of production of hydrogen with carbon sequestration to less than \$6.00/MMBtu and increase the efficiency of production to about 75 percent. Additional R&D and performance demonstration is necessary to verify this.

If hydrogen is produced in an advanced gasification coproduction facility that also generates electric power the production costs of the coproduced hydrogen can be reduced depending on the value of the power. If the coproduced electric power is valued at \$35.6/MWH (the cost of producing power from a natural gas combined cycle plant (NGCC)) hydrogen can be produced for about \$5.50/MMBtu. If the carbon dioxide is sequestered in this coproduction facility, the cost of hydrogen is only slightly increased if it is assumed that the coproduced power is valued at \$53.6/MWH (the cost of producing power from a sequestered NGCC plant). Utilization of advanced membrane separation technology has the potential to reduce hydrogen production costs to about \$4.00/MMBtu.

The greatest potential for reducing the production cost of hydrogen from coal is in configurations that include solid oxide fuel cells (SOFC). Coproduction facilities that use SOFC topping cycles to produce electric power and hydrogen have the potential to reduce the production cost of hydrogen to the range \$2.50 to \$3.00 per MMBtu. These costs could be achieved in facilities that sequester carbon dioxide at efficiencies around 65 percent. Clearly such potential warrants continuing RD&D in such integrated facilities that include advanced coal gasification, SOFC topping cycles, and advanced membrane separation technologies.

Costs of producing hydrogen from traditional steam methane reforming of natural gas are of course dependent on fuel costs. If natural gas is \$3.00/MMSCF then the resulting cost of hydrogen is \$4.80/MMBtu. Sustainable production of hydrogen from renewable sources like sunlight using photovoltaic (PV) water electrolysis could be a future goal. Continuing RD&D to significantly reduce the costs of PV systems is necessary for hydrogen production costs to be in the same range as production from coal. PV costs of about \$300 per peak kilowatt will be necessary to bring hydrogen production costs to the range \$7.00 to \$8.00 per MMBtu.

APPENDIX A

Appendix A

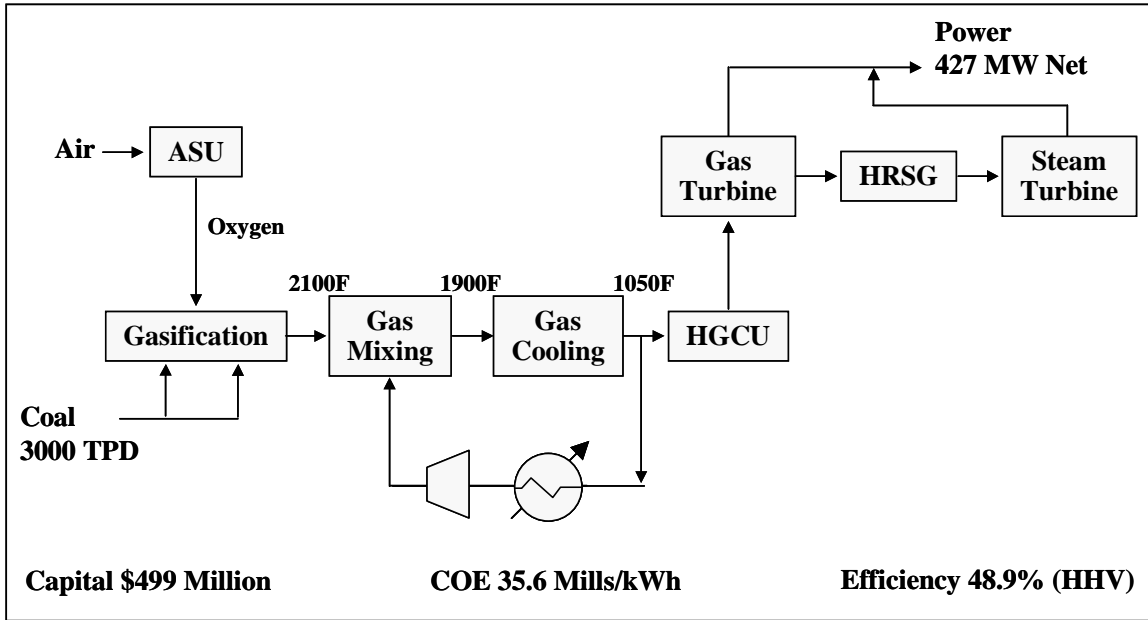


Figure A1: Baseline Advanced IGCC Facility

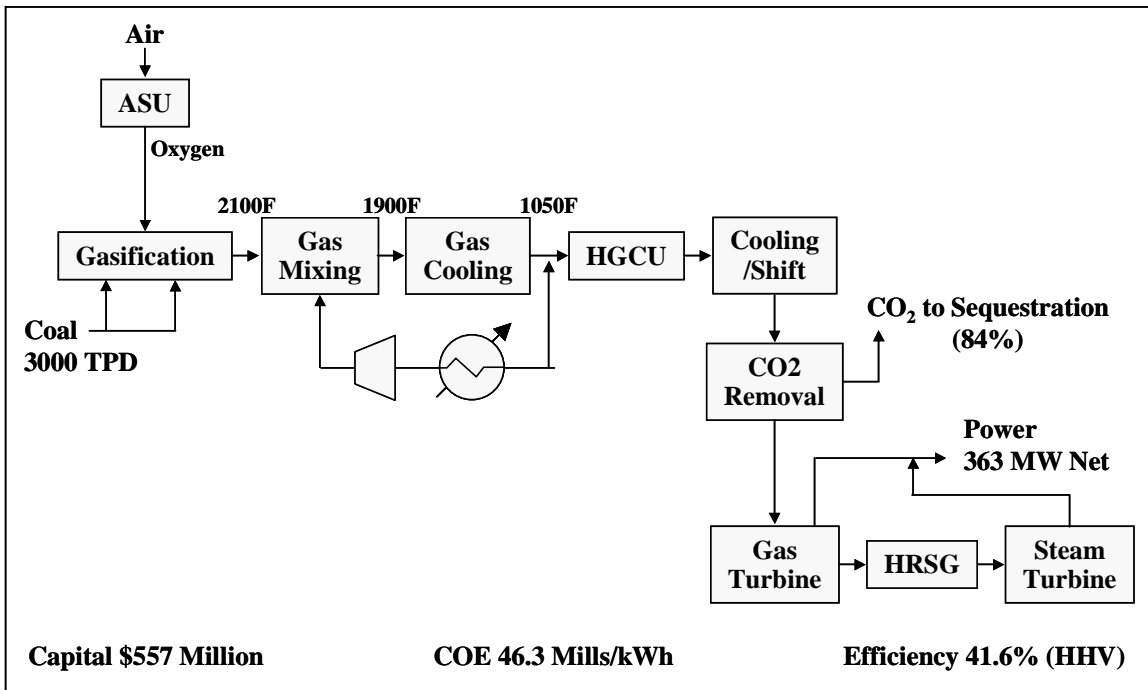


Figure A2: Baseline Advanced IGCC Facility with Sequestration

Appendix B

APPENDIX B

CASE 1: HYDROGEN PRODUCTION TEXACO QUENCH NO SEQUESTRATION

Construction Cost		Capital Cost		Operating Costs	
	\$MM(1998)				\$MM(1998)
Coal Handling	\$5	Construction Cost		Coal, Product RS /ton AR	\$27.3
Gasification/Quench/Cl	\$72	Home Office, Fee	8.40%	Consumables	\$1.6
Shift	\$20	Fee	2.00%	Labor/Overhead	\$7.7
Ai Separation	\$50	Project Contingency	15.00%	Administrativ Labor	\$1.2
F-T Synthesis	\$0	TOTAL DEPRECIABLE CAPITAL		Local Taxes & Ins. @ 2.00%	\$6.9
Hydrogen Removal	\$8			Other	\$8.9
CO2 Removal	\$14	Start-up Costs	5.00% Capital	GROSS OPERATING COST	\$53.5
Refining	\$0	Inventory Capital	10.00% GAOC	Sulfur, 80 /ton	\$2.0
Heat Rec/Power Gen	\$57			Ammonia, 150 /ton	\$0.0
Balance of Plant	\$45	TOTAL CAPITAL REQUIRED		TOTAL BY-PRODUCT CREDITS	\$2.0
TOTAL	\$271			NET OPERATING COSTS	\$51.5
Efficiency	63.75%	Power Cost, mils	20.4	Hydrogen, MMSCF/D	131
			35.6	Hydrogen Cost, \$/MSCI	\$2.22
				\$/MMBTU	\$6.83

CASE 2: HYDROGEN PRODUCTION TEXACO QUENCH, SEQUESTRATION

Construction Cost		Capital Cost		Operating Costs	
	\$MM(1998)				\$MM(1998)
Coal Handling	\$5	Construction Cost		Coal, Product RS /ton AR	\$27.3
Gasification/Quench/Cl	\$72	Home Office, Fee	8.40%	Consumables	\$1.6
Shift	\$19	Fee	2.00%	Labor/Overhead	\$7.7
Ai Separation	\$50	Project Contingency	5.00%	Administrativ Labor	\$1.2
F-T Synthesis	\$0	TOTAL DEPRECIABLE CAPITAL		Local Taxes & Ins. @ 2.00%	\$7.8
Hydrogen Removal	\$7			Other	\$10.0
CO2 Removal	\$25	Start-up Costs	5.00% Capital	GROSS OPERATING COST	\$55.6
Refining	\$0	Inventory Capital	10.00% GAOC	Sulfur, 80 /ton	\$1.9
Heat Rec/Power Gen	\$70			Ammonia, 150 /ton	\$0.0
Balance of Plant	\$70	TOTAL CAPITAL REQUIRED		TOTAL BY-PRODUCT CREDITS	\$1.9
TOTAL	\$316			NET OPERATING COSTS	\$53.7
Efficiency	59.06%	Power Cost, mils	26.9	Hydrogen, MMSCF/D	119
			53.6	Hydrogen Cost, \$/MSCI	\$2.66
				\$/MMBTU	\$8.18

APPENDIX B (Continued)

CASE 3: ADVANCED E-GAS, MEMBRANE SEPARATION

Construction Cost		Capital Cost		SMM(1998)	
Coal Handling	\$12	Construction Cost		\$341	
Gasification/Quench/Cln	\$125	Home Office, Fee	8.40%	\$29	
Air Separation	\$66	Process Contingency	2.00%	\$7	
Sulfur Polishing	\$0	Project Contingency	10.00%	\$34	
F-T Synthesis	\$0	TOTAL DEPRECIABLE CAPITAL		\$411	
Hydrogen Removal	\$5	Start-up Costs	2.52% Capital	\$10	
Refining	\$0	Inventory Capital	7.77% GAOC	\$4	
Heat Rec/Power Gen	\$62	TOTAL CAPITAL REQUIRED		\$425	
Balance of Plant	\$71				
TOTAL	\$341				
Efficiency	75.53%	Power	25.0	Hydrogen, MMSCF/D	158
		Cost, mils	53.6	Hydrogen Cost, \$/MSCI	\$1.91
				\$/MMBTU	\$5.89

ALL COAL COPROCESSING

Operating Costs		SMM(1998)
Coal,	\$29.0 /ton AR	\$27.6
Catalyst & Chemicals		\$6.8
Labor/Overhead		\$8.0
Administrativ Labor		\$1.3
Local Taxes & Ins. @	2.00%	\$8.3
Other		\$1.5
GROSS OPERATING COST		\$53.5
Sulfur,	80 /ton	\$1.9
Ammonia,	150 /ton	\$0.0
TOTAL BY-PRODUCT CREDITS		\$1.9
NET OPERATIN COST		\$51.7

CASE 4: COPRODUCTION OF POWER AND HYDROGEN, NO SEQUESTRATION

Construction Cost		Capital Cost		SMM(1998)	
Coal Handling	\$25	Construction Cost		\$690	
Gasification/Quench/Cln	\$253	Home Office, Fee	8.40%	\$58	
Air Separation	\$115	Process Contingency	2.00%	\$14	
Sulfur Polishing	\$15	Project Contingency	16.94%	\$117	
F-T Synthesis	\$0	TOTAL DEPRECIABLE CAPITAL		\$879	
Hydrogen Removal	\$13	Start-up Costs	2.52% Capital	\$22	
Refining	\$0	Inventory Capital	7.77% GAOC	\$8	
Heat Rec/Power Gen	\$180	TOTAL CAPITAL REQUIRED		\$910	
Balance of Plant	\$90				
TOTAL	\$690				
Efficiency	62.41%	Power	474.9	Hydrogen, MMSCF/D	149
		Cost, mils	35.6	Hydrogen Cost, \$/MSCI	\$1.76
				\$/MMBTU	\$5.42

ALL COAL COPROCESSING

Operating Costs		SMM(1998)
Coal,	\$29.0 /ton AR	\$55.3
Catalyst & Chemicals		\$13.8
Labor/Overhead		\$17.0
Administrativ Labor		\$2.8
Local Taxes & Ins. @	2.00%	\$17.8
Other		\$2.5
GROSS OPERATING COST		\$109.1
Sulfur,	80 /ton	\$3.8
Ammonia,	150 /ton	\$0.0
TOTAL BY-PRODUCT CREDITS		\$3.8
NET OPERATING COSTS		\$105.4

APPENDIX B (Continued)

Case 7: ADVANCED IGOX PLUS FUEL CELL

Construction Cost		\$MM(1998)	Capital Cost		\$MM(1998)	Operating Costs		\$MM(1998)
Coal Handling		\$13	Construction Cost		\$495	Coal,	\$29.0 /ton AR	\$27.6
Gasification/Quench/Cln		\$138	Home Office, Fee	8.40%	\$42	Catalyst & Chemicals		\$9.9
Air Separation		\$63	Process Contingency	2.00%	\$10	Labor/Overhead		\$11.7
Sulfur Polishing		\$0	Project Contingency	12.54%	\$62	Administrativ Labor		\$1.9
F-T Synthesis		\$143	TOTAL DEPRECIABLE CAPITAL		\$608	Local Taxes & Ins. @	2.00%	\$12.3
Hydrogen Removal		\$0				Other		\$1.5
CO2 Removal		\$0	Start-up Costs	2.52% Capital	\$15	GROSS OPERATING COST		\$65.0
Refining		\$0	Inventory Capital	7.77% GAOC	\$5	Sulfur,	80 /ton	\$1.9
Heat Rec/Power Gen		\$86				Ammonia,	150 /ton	\$0.0
Balance of Plant		\$51	TOTAL CAPITAL REQUIRED		\$628	TOTAL BY-PRODUCT CREDITS		\$1.9
TOTAL		\$495				NET OPERATING COSTS		\$63.1
Efficiency	65.68%		Power	567.1 (NET)				
			Cost, mills	33.7				

Case 8: SOFC Power, Sequestration of CO2

Construction Cost		\$MM(1998)	Capital Cost		\$MM(1998)	Operating Costs		\$MM(1998)
Coal Handling		\$14	Construction Cost		\$569	Coal,	\$29.0 /ton AR	\$29.3
Gasification/Quench/Cln		\$140	Home Office, Fee	8.40%	\$48	Catalyst & Chemicals		\$11.4
Air Separation		\$64	Process Contingency	2.00%	\$11	Labor/Overhead		\$13.4
Sulfur Polishing		\$30	Project Contingency	11.55%	\$66	Administrativ Labor		\$2.2
F-T Synthesis		\$143	TOTAL DEPRECIABLE CAPITAL		\$693	Local Taxes & Ins. @	2.00%	\$14.0
Hydrogen Removal		\$0				Other		\$1.6
CO2 Removal		\$23	Start-up Costs	2.52% Capital	\$17	GROSS OPERATING COST		\$71.8
Refining		\$0	Inventory Capital	7.77% GAOC	\$6	Sulfur,	80 /ton	\$2.0
Heat Rec/Power Gen		\$98				Ammonia,	150 /ton	\$0.0
Balance of Plant		\$56	TOTAL CAPITAL REQUIRED		\$717	TOTAL BY-PRODUCT CREDITS		\$2.0
TOTAL		\$569				NET OPERATING COSTS		\$69.8
Efficiency	61.32%		Power	529.4				
			Cost, mills	41.0				

ALL COAL COPROCESSING

Operating Costs		\$MM(1998)
Coal,	\$29.0 /ton AR	\$29.3
Catalyst & Chemicals		\$11.4
Labor/Overhead		\$13.4
Administrativ Labor		\$2.2
Local Taxes & Ins. @	2.00%	\$14.0
Other		\$1.6
GROSS OPERATING COST		\$71.8
Sulfur,	80 /ton	\$2.0
Ammonia,	150 /ton	\$0.0
TOTAL BY-PRODUCT CREDITS		\$2.0
NET OPERATING COSTS		\$69.8

APPENDIX B (Concluded)

Case 9: SOFC Power, H2 Sequestration of CO2

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)		
Coal Handling	\$25	Construction Cost	\$814		
Gasification/Quench/Cln	\$253	Home Office, Fee	8.40%	\$68	
Air Separation	\$115	Process Contingency	2.00%	\$16	
Sulfur Polishing	\$30	Project Contingency	12.82%	\$104	
F-T Synthesis	\$143	TOTAL DEPRECIABLE CAPITAL		\$1,003	
Hydrogen Removal	\$8	Start-up Costs	2.52% Capital	\$25	
CO2 Removal	\$42	Inventory Capital	7.77% GAOC	\$9	
Refining	\$0	TOTAL CAPITAL REQUIRED		\$1,037	
Heat Rec/Power Gen	\$121				
Balance of Plant	\$76				
TOTAL	\$814				
Efficiency	64.47%	Power	509.3	Hydrogen, MMSCF/D	149
		Cost, mils	53.6	Hydrogen Cost, \$/MSCI	\$0.91
				\$/MMBTU	\$2.79

ALL COAL COPROCESSING

Operating Costs	\$MM(1998)
Coal, \$29.0 /ton AR	\$55.3
Catalyst & Chemicals	\$16.3
Labor/Overhead	\$19.4
Administrativ Labor	\$3.1
Local Taxes & Ins. @ 2.00%	\$20.3
Other	\$2.5
GROSS OPERATING COST	\$116.8
Sulfur, 80 /ton	\$3.8
Ammonia, 150 /ton	\$0.0
TOTAL BY-PRODUCT CREDITS	\$3.8
NET OPERATING COSTS	\$113.1

Case 10: SOFC Power, H2, Membrane, Sequestration of CO2

Construction Cost	\$MM(1998)	Capital Cost	\$MM(1998)		
Coal Handling	\$25	Construction Cost	\$794		
Gasification/Quench/Cln	\$253	Home Office, Fee	8.40%	\$67	
Air Separation	\$115	Process Contingency	2.00%	\$16	
Sulfur Polishing	\$0	Project Contingency	13.75%	\$109	
F-T Synthesis	\$162	TOTAL DEPRECIABLE CAPITAL		\$985	
Hydrogen Removal	\$14	Start-up Costs	2.52% Capital	\$25	
CO2 Removal	\$0	Inventory Capital	7.77% GAOC	\$9	
Refining	\$0	TOTAL CAPITAL REQUIRED		\$1,019	
Heat Rec/Power Gen	\$150				
Balance of Plant	\$75				
TOTAL	\$794				
Efficiency	65.24%	Power	518.7	Hydrogen, MMSCF/D	150
Jay as recieved III#6 Coal		Cost, mils	41.0	Hydrogen Cost, \$/MSCI	\$1.81
				\$/MMBTU	\$5.58

ALL COAL COPROCESSING

Operating Costs	\$MM(1998)
Coal, \$29.0 /ton AR	\$55.3
Catalyst & Chemicals	\$15.9
Labor/Overhead	\$19.0
Administrativ Labor	\$3.1
Local Taxes & Ins. @ 2.00%	\$19.9
Other	\$2.5
GROSS OPERATING COST	\$115.7
Sulfur, 80 /ton	\$3.7
Ammonia, 150 /ton	\$0.0
TOTAL BY-PRODUCT CREDITS	\$3.7
NET OPERATING COSTS	\$111.9