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Current and Future IGCC Technologies: Bituminous Coal to Power

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EXECUTIVE SUMMARY

The United States Department of Energy's (DOE) Office of Coal and Environmental Systems Gasification Technologies Program is funding research and development (R&D) whose objective is to improve the efficiency and reduce the costs of advanced Integrated Coal Gasification Combined Cycle (IGCC) technologies. In order to evaluate the benefits of the ongoing R&D, DOE has asked Mitretek Systems to utilize their Energy Systems Analysis capabilities and conceptual computer simulation models to quantify the potential impact of successful R&D on future IGCC configurations.

Fifteen (15) IGCC configurations that produce electric power from bituminous coal were analyzed in this report. Twelve cases do not have carbon capture and 3 cases capture carbon. Case 1 is the baseline or current IGCC configuration. This configuration uses single-stage, slurry feed gasification with radiant gas cooling followed by conventional amine-based cold gas cleaning, F-frame gas turbine and conventional steam turbine. Cases 2 and 3 use the same overall configuration but the capacity factor has increased from 75 percent to 85 percent in case 2, and the carbon utilization is assumed to increase from 95 percent to 98 percent in case 3. In case 4, it is assumed that the single-stage, slurry feed gasification system is replaced by a two-stage slurry phase gasification system. Case 5 assumes incorporation of a single stage dry feed coal gasifier system in place of the slurry feed systems. Case 6 uses the dry feed gasifier integrated with an advanced FB-frame gas turbine. Case 7 has the same components as case 6 except that the conventional cold gas cleaning is replaced by a warm gas cleanup system. The warm gas cleaning system chosen for this analysis was the selective catalytic oxidation of hydrogen sulfide (SCOHS) process. In case 8, the cryogenic air separation unit (ASU) is replaced by the novel ionic transport membrane (ITM) system for air separation. This system is integrated into the overall IGCC configuration. Case 9 is the same configuration as case 8 except that the plant capacity factor is increased from 85 to 90 percent. Case 10 assumes the incorporation of the H-Frame gas turbine in place of the FB turbine. In case 11, a solid oxide fuel cell (SOFC) is used as a topping cycle before the gas turbine. Finally, case 11(60) has the same configuration as case 11; however, the ratio of the power generated from the SOFC and the turbines is adjusted to obtain an overall efficiency of coal to net power of 60 percent high heating value (HHV). Table ES-1 summarizes the configurations for these cases. All of the forgoing cases 1 through 11(60) are configurations that do not capture carbon dioxide.

Table ES-2 summarizes the results of the analysis for these twelve (12) non-carbon capture IGCC cases. Current IGCC technology (case 1) is estimated to have an overall efficiency of 40 percent (HHV), a capital cost of $1,294/kilowatt (kW), and a capacity factor of 75 percent. The required selling price (RSP) of the electric power from this current plant is calculated to be $45.20/megawatt hour (MWH). This RSP is called the cost of electricity

Table ES-1. Cases Analyzed: No Carbon Capture Bituminous Coal to Power

Case	Description	
1	Base Case Single stage slurry feed	75% Cap/95% Carbon Util (Current Technology)
2	Single stage slurry feed	85% Cap/95% Carbon Util
3	Single stage slurry feed	85% Cap/98% Carbon Util
4	2-stage slurry feed	85% Cap/98% Carbon Util
5	Dry Feed	85% Cap/98% Carbon Util
6	Dry Feed	85% Cap/98% Carbon Util/FB Turbine
7	Dry Feed	85% Cap/98% Carbon Util/FB/SCOHS
8	Dry Feed	85% Cap/98% Carbon Util/FB/SCOHS/ITM
Date 2010		
9	Dry Feed	90% Cap/98% Util/FB/SCOHS/ITM
10	Dry Feed	90% Cap/98% Util/H-Turbine/SCOHS/ITM
11	Dry Feed	90% Cap/98% Util/F/SCOHS/ITM/SOFC
11(60)	Dry Feed	90% Cap/98% Util/F/SCOHS/ITM/SOFC/60% eff.
Date 2020		

*Cap = Capacity
**Util = Utilization
***eff = Efficiency

(COE) in Table ES-2. Improvements to this current configuration include increasing the capacity factor to 85 percent and increasing the carbon utilization in the gasifier from 95 percent to 98 percent. These improvements are shown in column 3 of Table ES-2 and result in an increase in efficiency to 41.1 percent, a reduction in the capital to $1,279/kW, and a decrease in the COE to $40.60/MWH.

Table ES-2. Summary: Bituminous Coal to Power (No Carbon Captured)

Case	1	2	3	4	5	6	7	8	9	10	11	11(60)
COE ($/MWH)	45.2	41.2	40.6	39.4	38.3	36.4	34.6	32.7	31.5	29.6	29.2	29.7
Capital ($MM)	702	702	692	640	622	660	625	614	614	430	580	536
Efficiency (%)	40.0	40.0	41.1	42.7	45.1	46.7	47.9	48.3	48.3	50.5	64.9	60
Output (MW)	543	543	541	516	511	574	575	598	598	451	579	535
Capital ($/kW)	1,294	1,294	1,279	1,241	1,217	1,149	1,086	1,027	1,027	953	1,002	1,002
Coal Feed (TPD)	4,761	5,396	4,620	4,241	3,977	4,316	4,215	4,358	4,614	3,134	3,132	3,132
Capacity (%)	75	85	85	85	85	85	85	85	90	90	90	90
Target Year								2010			2020	
Target Cost ($/kW)								1000			900	
Target Efficiency (% HHW)								50			60	

Case 4 estimates the impact of a change in coal gasifier type from slurry feed, single stage entrained to two-stage entrained. This change improves efficiency to 42.7 percent, reduces capital to $1,241/kW, and reduces the COE to $39.40/MWH. In case 5, the gasifier is changed to reflect a dry feed entrained type. This has a positive effect on efficiency increasing it to 45.1 percent, reduces the capital to $1,217/kW, and reduces the COE to $38.30/MWH.

Case 6 estimates the impact of substituting the more efficient FB-frame gas turbine for the F-frame turbine. Efficiency is increased to 46.7 percent, capital is reduced to $1,149/kW, and the resulting COE is reduced to $36.40/MWH. In case 7, the impact of replacing the conventional cold gas cleaning (amine based) system with the SCOHS system improves the efficiency to 47.9 percent, reduces the capital to $1,086/kW, and reduces the COE to $34.60/MWH.

In case 8, the potential impact of replacing the cryogenic ASU with the ITM system was analyzed. The ITM technology is currently in the R&D phase but it was assumed that this R&D would be successful in developing a commercial scale unit. Replacing the ASU with the novel ITM system was estimated to increase the IGCC plant efficiency to 48.3 percent, reduce the capital to $1,027/kW, and reduce the COE to $32.7/MWH.

Case 9 is the same as case 8 except that the capacity factor has increased to 90 percent. This results in a decrease in the COE to $31.50/MWH. Case 10 assumes the availability of the H-frame gas turbine and this more efficient machine increases the overall plant efficiency from coal to electricity to 50.5 percent. The capital cost is reduced to $953/kW and the COE is reduced to $29.60/MWH.

Case 11 assumes the integration of SOFC technology as a topping cycle before the gas turbine. Because it is assumed that the SOFC has efficiency to electric power of 60 percent and the waste heat from the SOFC can be captured effectively, the impact on overall plant efficiency is significant. In this case, the efficiency is increased to 64.9 percent, the capital is $1,002/kW, and the COE is $29.2/MWH. The capital is higher than case 10 because of the incorporation of the SOFC units that are assumed to have a capital cost of $400/kW. This cost is almost twice as high as a comparable gas turbine cost. In case 11(60), the plant was designed to achieve an overall efficiency of 60 percent by adjusting the contribution of power from the fuel cell and the turbines. In this case, the overall efficiency was 60 percent, the capital was $1,002/kW, and the resulting COE was $29.7/MWH.

The results from these simulated IGCC plants show that there are potentially significant improvements that could result from continuing research development and demonstration (RD&D) in advanced IGCC systems, provided that the RD&D achieves the performance and cost levels assumed in this analysis. These are estimated to be:

- Advanced technology could reduce COE by about 35 percent compared to current IGCC technology
- A reduction in IGCC capital cost from a current cost of around $1300/kW to below $1000/kW
- An improvement in overall IGCC plant efficiency from a current value of about 40 percent (HHV) to over 60 percent (HHV).

Three (3) carbon capture cases are also analyzed in this report. They are:

- Case 12: A current single-stage slurry feed gasification based IGCC plant with raw gas shift, conventional gas cleaning, and 7 F-frame gas turbines.
- Case 13: An IGCC configuration representing the year 2010 with advanced dry feed coal gasification, warm gas cleaning, 7 FB-frame gas turbines, and ITM oxygen in place of conventional cryogenic ASU.
- Case 14: An IGCC configuration representing the year 2020 with advanced gasification, warm gas cleaning, ITM oxygen production, and SOFC topping cycle.

Table ES-3 summarizes the results of the conceptual IGCC plant analyses for the three carbon dioxide capture cases. In case 12, the plant configuration is very similar to the case 1 baseline plant except that this case incorporates raw water gas shift and bulk carbon dioxide removal and compression. This plant processes 5,037 TPD of as-received coal to produce 491 MW of net power at an efficiency of 34.2 percent. This can be compared to 40 percent (HHV basis) for the case 1 baseline plant with no carbon capture: a 15 percent lower efficiency. In case 12, about 90 percent of the carbon in the feed coal is captured. Net power output is 491 MW and total plant cost to $813 MM. This results in a capital cost per unit power capacity of $1,656 per kW. The RSP of electricity for this IGCC plant is calculated to be $56.99 per MWH.

The case 13 plant concept is very similar to the case 8 IGCC plant in that the coal is gasified in a dry feed gasifier, an ITM system is used for air separation, SCOHS is used for sulfur removal, and 7 FB-frame gas turbines are used for power generation. However, in this case, all of the carbon dioxide produced is captured. This plant processes 4,394 TPD of as-received coal to produce 523 MW of net power. Overall efficiency of the carbon capture plant is 41.7 percent and this can be compared to 48.3 percent (HHV) for the case 8 plant with no carbon capture. This carbon capture plant is a zero emission plant with respect to carbon dioxide. The configuration uses an oxygen fired gas turbine combustor and a hydrogen fired combustor for preheating the ITM air. Net power output is 523 MW, and total plant capital cost is $720 MM. This results in a capital per unit power capacity of $1,377 per kilowatt. The RSP of electricity for this carbon capture IGCC plant is calculated to be $43.04 per MWH.

Table ES-3. Summary: Bituminous Coal to Power (Carbon Capture)

Case	12	13	14
COE ($/MWH)	56.99	43.04	35.42
Capital ($MM)	813	720	662
Efficiency (%)	34.2	41.7	59.7
Output (MW)	491	523	533
Capital ($/kW)	1,656	1,377	1,242
Coal Feed (TPD)	5,037	4,394	3,135

Case 14 is similar in concept to case 11 described above. SOFC stacks are used as the topping cycle before the gas turbine in an IGCC configuration. The main difference between case 14 and case 11 is that all of the carbon dioxide produced in the plant is captured. Net power output is 533 MW and the overall efficiency is 59.7 percent. This can be compared to the efficiency of the case 11 plant at 65 percent. This plant is also a zero emissions plant with respect to carbon dioxide. In case 14, the total capital is $662 MM. Excluding non-depreciable capital, this is a capital investment cost of $1,242/kW. The RSP of the electric power from this plant is calculated to be $35.42 per MWH.

These results show that there are potentially significant improvements that could result from continuing RD&D in advanced IGCC systems with carbon capture. These are:

- Advanced IGCC technology has the potential to reduce COE by about 38 percent compared to current IGCC carbon capture technology.
- A reduction in IGCC capital cost from a current cost of around $1660/kW to $1,240/kW for carbon capture IGCC plants.
- An improvement in overall IGCC plant efficiency from a current value of about 34 percent (HHV) to almost 60 percent (HHV) for carbon capture IGCC plants.

The main RD&D issues emanating from this analysis are as follows:

- Warm gas cleaning processes are important to the overall IGCC system because at higher temperatures the gas maintains moisture content and some sensible heat. The SCOHS process is particularly attractive because it promises to perform the dual function of removing hydrogen sulfide and recovering sulfur in one simple reactor at temperatures around 300°F. However, it should be cautioned that the SCOHS process has yet to be demonstrated at a commercial scale especially the monolithic design concept. Raw coal derived synthesis gas is dirty and contains many constituents that must be removed before the gas turbine. These include particulates, chlorides, cyanide, ammonia, maybe carbonyls, hydrogen sulfide, carbonyl sulfide, and trace metals including mercury. Water scrubbing of the gas generally removes chloride, ammonia, and cyanide, but water scrubbing reduces the temperature of the synthesis gas to around 400°F. Warm cleaning systems that remove and recover hydrogen sulfide and that operate around 300-400°F would then be compatible with water scrubbing of the gas and hydrolysis of carbonyl sulfide that is favored around 375°F. Failing the development of an ideal system that would operate at gasifier outlet temperatures around 2000°F, remove all of the impurities and provide a clean gas for the turbines, the SCOHS process is a worthy candidate for R&D. There is, however, a potential problem concerning the effective removal of mercury at warm gas cleaning temperatures. This analysis assumed that mercury could be removed in the temperature range 300-400°F. However, if removal requires low synthesis gas temperatures as practiced at the Eastman Texaco plant, then warm gas cleaning would have to be followed by gas cooling and mercury removal at low temperature in activated carbon beds. SCOHS would, however, retain much of its advantage by eliminating the Claus and Shell Claus Offgas Treatment (SCOT) units for sulfur recovery.

- It was evident from this analysis that advanced gas turbines contribute significantly to improved overall efficiency and lower costs of electricity. R&D on the successful development of the FB and H-Frame machines on synthesis gas and integration of the gas turbines with the air separation unit and the overall IGCC system ***must*** be an important priority in any IGCC RD&D program plan.
- Air separation using the ITM system did contribute to improvements in the IGCC system if the performance estimates used in this analysis can be demonstrated at commercial scale. Because of the high temperature of operation of ITM (circa 1600°F) heat management and optimal integration into the IGCC system are critical issues. In many of the analyses in this report, the ITM system is integrated with the gas turbine. It is assumed that the gas turbine compressor is used to compress the air to the ITM as well as the air to the gas turbine combustor. A synthesis gas burner is used to preheat the ITM feed air and hot ITM depleted air effluent is sent to the gas turbine combustor. This integration is conceptual and none of this integration has been demonstrated in practice. R&D is needed to demonstrate these integrations and define the optimal integrated configuration for these units. When the ITM is integrated with a SOFC, it is assumed, in this report that the hot ITM depleted air effluent can be sent directly to the SOFC cathode. R&D is needed to optimize integration of fuel cells with the ITM system.

- The incorporation of a SOFC into the IGCC system had a dramatic effect on overall system efficiency. In this report, it was assumed that large scale stationary SOFC stacks could be commercialized that generated over 300 MW of power and cost $400/kW. Fuel cell development is currently at an early stage, and fuel cell stacks are currently less than a MW. Considerable RD&D will be needed to prove these units at large scale. In addition, it was assumed that these SOFCs could operate at pressures compatible with gas turbine inlet pressures of around 16 to 20 bar. Higher pressure operation of SOFC must be proven. Also the system integration of the SOFC with the ITM unit and the gas turbine needs to be demonstrated.
- The importance of IGCC capacity factor was quantified in this report. Reliable coal gasification operation with high availability and maintainability is a critically important issue that can contribute to lowering the COE from IGCC plants. ***Industry will not embrace IGCC as a technology until it can prove to be as reliable as conventional pulverized coal technologies.*** It is capital intensive to have spare gasifiers at the IGCC plant and operating and maintenance (O&M) costs are increased if they have to be kept on standby mode. On stream capacity for single gasifier units should be as high as possible, around 85 percent (or 310 days per year on stream). IGCC plants when built will have the lowest dispatch power cost of the generating system; and therefore, will generate power at base load to the fullest extent possible. RD&D to improve gasifier reliability, availability and maintainability (RAM) must be an essential part of an IGCC deployment program. ***The ultimate goal would be to produce bankable, standard, reliable IGCC designs, just as today there are reliable standard PC plant designs.***

Acknowledgement

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Table of Contents

Section		Page

List of Figures

List of Tables

1.0 Introduction

The United States Department of Energy's (DOE) Office of Coal and Environmental Systems Gasification Technologies Program is funding research & development (R&D) whose objective is to improve the efficiency and reduce the costs of advanced Integrated Gasification Combined Cycle (IGCC) technologies. In order to evaluate the benefits of the ongoing R&D, DOE has asked Mitretek Systems to utilize their Energy Systems Analysis capabilities, and conceptual computer simulation models to quantify the potential impact of successful R&D on the integrated IGCC system.

Mitretek Systems has developed in-house detailed computer simulation models of IGCC configurations. These models simulate the gasification of coal to clean synthesis gas and the subsequent utilization of this gas in gas turbine and steam turbine cycles. The models provide complete material and energy balances of the system and are flexible with respect to technology and configuration. They also estimate capital and operating costs and calculate the required selling price (RSP) of the electric power based upon standard discounted cash flow (DCF) analysis. Emerging advanced gasification, gas cleaning, and gas and steam turbine technologies can be incorporated into the baseline current IGCC configuration. Also, advanced air separation technology and fuel cell technologies can be integrated into the IGCC configuration. Incorporation of these advanced technologies into the current or baseline IGCC plant allows an estimate of the potential benefits of these technologies to be quantified. These benefits are measured ultimately in terms of the reduction in production cost of the electric power.

In this report, we have first established a baseline or current IGCC configuration. This plant is based on similar technology to that of the Polk IGCC plant in Florida. Sequential improvements have then been assumed for this base plant. These improvements include a greater on-stream time or capacity factor, greater carbon utilization, more advanced gasification technology, advanced warm gas cleaning, advanced gas turbine systems, ceramic membrane technology for air separation, and finally integration of solid oxide fuel cells as a topping cycle before the gas turbine. To the extent possible, a similar plant size was used. However, because the gas turbine input determines to a great extent the plant size, when advanced turbines were used the overall plant size was adjusted to be compatible with gas turbine input.

Although all of the plants described above have very low emissions of sulfur oxides (SOx), nitrogen oxides (NOx), mercury, and PM, they do not attempt to capture carbon dioxide. Because of concerns over climate change and the interest in development of essentially zero emissions coal plants, we have also analyzed three IGCC configurations that do capture carbon dioxide to various degrees. The impacts on the performance and the cost of electricity of these carbon capture configurations were estimated.

The ultimate goal of the DOE research development and deployment (RD&D) program in IGCC is to allow the utilization of coal for power production to be as clean, as efficient, and as economic as power produced from inexpensive natural gas. The DOE target for the year 2010 is to produce power from coal at an efficiency of 50 percent high heating value (HHV) with a capital cost of about $1000/kilowatt (kW). The target for year 2020 is to produce electric power from coal at an efficiency of 60 percent (HHV) at a capital cost of about $900/kW. These are targets for IGCC technologies that do not capture and sequester carbon dioxide.

Figure 1 shows the target values plotted on a timeline from the present out to the year 2020. Also plotted on this timeline, are the expected time sequence for deployment of the various technologies and performances analyzed in this report. For example, by year 2006, it is expected that coal gasification will achieve capacity factors of 85 percent. The capacity factor is defined as the total days in the year that the gasifier is operating divided by the total days in a year. Also by year 2006, the carbon utilization will increase to 98 percent of the feed carbon in the coal. Dry feed gasifiers are also expected to be ready for deployment by that date. By year 2008, warm gas cleanup (WGCU) technology and ionic transport membrane (ITM) technology for air separation are expected to be ready for deployment. By year 2012, coal gasification reliability is expected to improve to result in an increased capacity of 90 percent. H-Frame gas turbines are also expected to be deployed by that time. By year 2018, solid oxide fuel cells (SOFC) are expected to be available to be used as topping cycles for the combined cycle system.

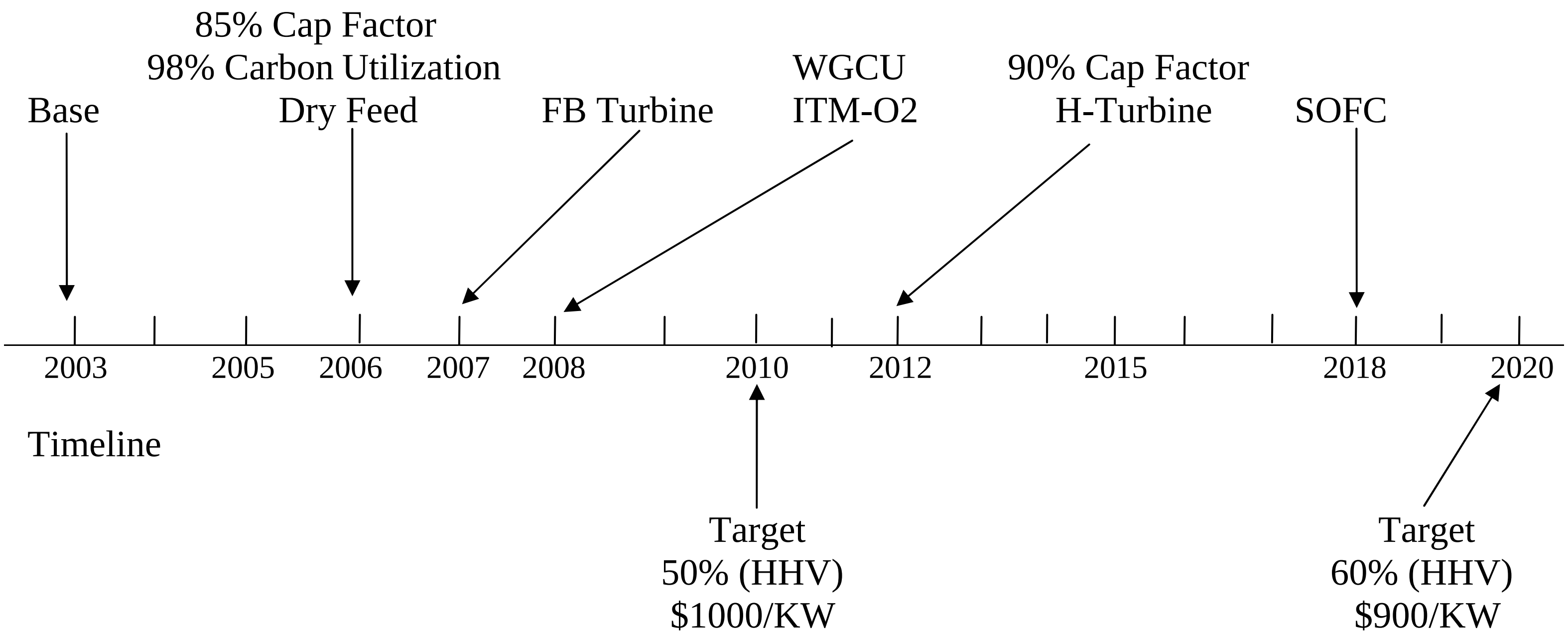


Figure 1. Technology Time Sequence for Deployment

2.0 Coal Analysis

Table 1 shows the analysis of the coal feed assumed for all of the cases analyzed in this report. This is an Illinois number 6-bituminous coal from the Old Ben #26 mine.

Table 1. Coal Analysis: Illinois #6 Old Ben #26 Mine

Proximate As-received (wt %)

Moisture	11.12
Ash	9.7
Volatile Matter	34.99
Fixed Carbon	44.19
HHV Btu/#	11,666

Ultimate As-received (wt %)

Moisture	11.12
Carbon	63.75
Hydrogen	4.5
Nitrogen	1.25
Chlorine	0.29
Sulfur	2.51
Ash	9.7
Oxygen (bd)	6.88

3.0 IGCC Cases Analyzed

Table 2 describes the twelve (12) IGCC configurations analyzed in this report that do not capture carbon dioxide. A brief description will be given of these cases in this section and a more detailed description will be given in Section 4.

Case 1 is the baseline or current IGCC configuration. This configuration uses a single-stage, slurry feed gasification system with radiant gas cooling followed by conventional amine-based cold gas cleaning, a General Electric F-frame gas turbine and conventional steam turbine. Cases 2 and 3 use the same overall configuration but the capacity factor has increased from 75 percent to 85 percent in case 2 and the carbon utilization is assumed to increase from 95 percent to 98 percent in case 3. In case 4, it is assumed that the single-stage entrained flow gasification system is replaced by a two-stage entrained gasification system similar in concept to the ConocoPhillips E-gas system. This gasifier is operating at the Wabash repowering facility in Indiana.[1] Case 5 assumes incorporation of a single stage dry coal feed gasifier system in place of the slurry feed systems. This gasifier is similar in concept to the Shell gasifier.[2] Case 6 uses the dry feed gasifier integrated with an advanced gas turbine similar in concept to the GE FB-Frame machine. Case 7 has the same components as case 6, except that the conventional cold gas cleaning is replaced by a warm gas cleanup system. In case 8, the cryogenic air separation unit (ASU) is replaced by the novel Ionic Transport membrane (ITM) system for air separation.[3] This system is integrated into the overall IGCC configuration. Case 9 is the same configuration as case 8 except that the plant capacity factor is increased from 85 to 90 percent. Case 10 assumes the incorporation of a more advanced gas turbine similar in concept to the GE H-frame machine in place of the FB-turbine. In case 11, a solid oxide fuel cell (SOFC) is used as a topping cycle before the gas turbine. Finally, case 11(60) has the same configuration as case 11; however, the ratio of the power generated from the SOFC and the turbines is adjusted to obtain an overall efficiency of coal to net power of 60 percent (HHV). Detailed analysis of emissions were not undertaken in this report but it was assumed that emissions of SOx were reduced by 99 percent and NOx emissions were assumed to be less than).07 pounds per MMBtu.

All of the forgoing cases 1 through 11 are configurations that do not capture carbon dioxide. Three more cases were analyzed that used configurations that allow capture of the carbon dioxide. These three cases (12, 13, and 14), will be described later.

Table 2. Cases Analyzed: No Carbon Capture Bituminous Coal to Power

Case		Description
1	Base	75% Cap*/95% Carbon Utilization/F turbine(Current Technology)
2	Single stage Slurry gasification	85% Cap/95% Carbon Util**/F turbine
3	Single stage Slurry gasification	85% Cap/98% Carbon Util/F turbine
4	Two stage Slurry gasification	85% Cap/98% Carbon Util/F turbine
5	Dry Feed Gasifier	85% Cap/98% Carbon Util/F turbine
6	Dry Feed	85% Cap/98% Carbon Util/FB Turbine
7	Dry Feed	85% Cap/98% Carbon Util/FB/SCOHS
8	Dry Feed	85% Cap/98% Carbon Util/FB/SCOHS/ITM
Date 2010		
9	Dry Feed	90% Cap/98% Util/FB/SCOHS/ITM
10	Dry Feed	90% Cap/98% Util/H-Turbine/SCOHS/ITM
11	Dry Feed	90% Cap/98% Util/GT/SCOHS/ITM/SOFC
11(60)	Dry Feed	90% Cap/98% Util/GT/SCOHS/ITM/SOFC/60% eff.
Date 2020		

*Cap – Capacity
**Util – Utilization
***eff = efficiency

4.0 Analysis of Non-Carbon Capture Cases

4.1 Case 1: Baseline Case: Single-Stage Slurry Feed Gasification with 75 Percent Capacity and 95 Percent Carbon Utilization

Figure 2 shows a schematic of the Base case IGCC plant that is used in this study as the benchmark from which all subsequent improvements are measured. This configuration shows a plant with two trains of single-stage slurry feed gasification with radiant heat recovery, two cryogenic air separation units, two trains of water scrub and carbonyl sulfide (COS) hydrolysis, two trains of conventional amine-based acid gas removal (AGR), one train of sulfur recovery using conventional Claus/SCOT technology, two trains of F-frame gas turbines, one heat recovery steam generator (HRSG), and one steam turbine system with high, intermediate, and condensing turbine sections. Steam conditions assumed are 1800 psi and 1000F for the HP turbine and 405 psi and 1000F for the IP turbine. This plant has all necessary supporting and off-site units.

Table 3 summarizes the process flows for selected streams for the case 1 plant configuration. Flows are in pound moles per hour. This two train gasification plant processes 4,760 tons per day (TPD) of as-received coal to produce 543 megawatt (MW) of net power. Overall efficiency is thus 40 percent (HHV basis). Carbon utilization is 95 percent and the capacity factor is 75 percent. Total power generated is 650 MW, 393 MW from the gas turbine and 257 MW from the steam turbine. Parasitic power required is estimated to be 107 MW with the largest user being the ASU at 60 MW. The major material streams are shown (8 streams) including gasifier input and output, gas turbine fuel, oxygen feed, and feed to the HRSG.

The summary of the plant capital and operating and maintenance costs is shown in Table 4. The total installed plant construction cost is estimated to be $553 million. Addition of home office, process and project contingency brings the total plant cost to $702 MM. With addition of depreciable capital the total capital cost of the baseline case 1 plant is estimated to be $726MM. This results in a capital per unit power capacity of $1,295/kW if non-depreciable capital is excluded (net power output is 543 MW). Net annual operating and maintenance costs after by-product credit reduction are estimated to be $75.9 MM. Coal feedstock cost at $29.40 per ton ($1.26 per million Btu HHV basis) is $38.32 MM.

This economic data was used to calculate the RSP of the electric power from this plant. The economic assumptions used in the discounted cash flow analysis (DCF) are shown in Table 5. These assumptions were used to maintain consistency with prior Mitretek reports. Using these financial assumptions, the RSP of electricity is calculated to be $45.20 per megawatt hour (MWH).

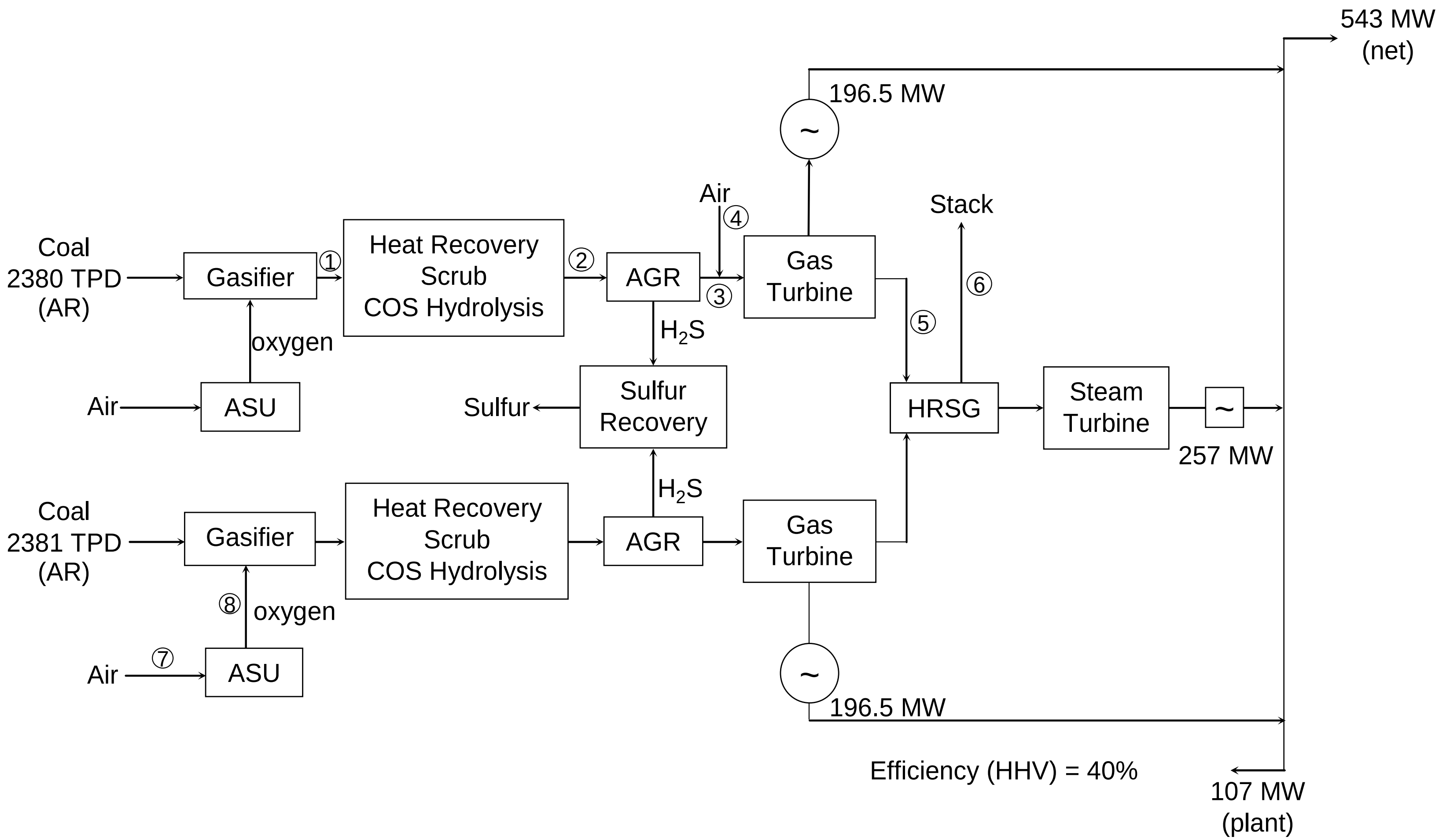


Figure 2. Case 1: Current Baseline IGCC Configuration

Table 3: Case 1 Base Single Stage Slurry Feed 75 Percent Cap/95 Percent Carbon Utilization
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8
	Gasifier Output	Cooler/COS Exit	Fuel to Gas Turbine	Air to Gas Turbine	Feed to HRSG	HRSG EXIT	Air to ASU	Oxygen to Gasifier
CH4	1	1	0					
H2O	9,468	2,988	0		11,233	11,233		
H2	11,368	11,368	11,225					
CO	15,981	15,981	15,843					
CO2	4,047	4,047	3,815		19,659	19,659		
O2	0	0	0	52,066	28,950	28,950	9,770	9,770
N2	765	765	759	197,537	198,296	198,296	37,066	514
H2S	311	311	NIL		NIL	NIL		
NH3	TRACE	NIL	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		
Hg	TRACE	TRACE	TRACE		TRACE	TRACE		
COS	TRACE	TRACE	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		
Total	41,941	35,460	31,644	249,603	258,139	258,139	46,836	10,284
Temperature, F	2,600	265	550	764	1,073	260	686	302
Pressure, Psia	425	348	208	208	15	15	196	446
Power Summary, MW			Coal Input, T/Day AR		4,761			
Production:	MW							
Steam Turbine	257							
Gas Turbine	393		Gasifier Input,	1000#/Hr				
Total	650		Coal	314				
			Ash	38				
Plant Use:			H2O (coal)	44				
ASU	61		H2O (slurry)	178				
Oxygen Compression	14		O2	313				
Miscellaneous	32							
Total	107							
			Efficiency	40.00%				
Net Output	543							

Table 4. Case 1: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	45
Gasification	130
Air Separation Unit	72
Acid Gas Removal	26
Sulfur Recovery	26
Gas Turbine	69
HRSG	35
Steam Turbine	37
Cooling/Feed Water Systems	35
Balance of Plant	78
Total Installed Cost	**553**
Home Office (8.4%)	46
Process Contingency (2%)	11
Project Contingency (15%)	92
Total Plant Cost	**702**
Non-depreciable Capital	24
Total Capital	**726**

Operating & Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	38.32
Cat/Chem Materials	8.30
Water	0.83
Operating and Maintenance Labor	9.70
Overhead/G&A	3.90
Administrative Labor	2.20
Local Taxes and Insurance	14.00
Solid Disposal	1.26
Gross Annual Operating Cost	78.51
By-product Credit	2.60
Net Annual Operating Cost	**75.91**

Net Power Output = 543 MW

RSP of Electricity (COE) = $45.20/MWH

Table 5. Discounted Cash Flow Analyses Assumptions

Initial Plant Output 50% (Year 1) 90% (Year 2)

Debt: Equity = 67:33

Required Selling Price (RSP) in constant dollars necessary for 15% ROE (current $)

Debt: 16 years @ 8% interest

General inflation 3%

Escalation in accordance with EIA projects

Depreciation 16 years with double declining balance

Federal and state income tax (Fed 34%) (State 6%)

Local tax and insurance 2% of depreciable capital

4.2 Cases 2 and 3: Single-Stage Slurry Feed Gasification with 85 Percent Capacity and 95 Percent Carbon Utilization (Case 2) and 98 Percent Carbon Utilization (Case 3)

Cases 2 and 3 have the same configuration as case 1 (see Figure 2). In case 2, the only difference is that the capacity factor has been increased from 75 percent (that is the plant is producing power for 365*0.75 or 274 days of the year) to 85 percent or 310 days per year. Table 6 is a summary of the plant capital and operating and maintenance costs. In case 2, the total installed plant construction cost is unchanged from the base case at $553 million and the total capital cost of the case 2 plant is thus $726 MM. Net plant power output is the same as the base case at 543 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $82.17 MM. This is higher than the base case because of the increase in variable operating cost and fuel cost due to a greater capacity factor. Coal feedstock cost at $29.40 per ton ($1.26 per million Btu HHV basis) is $43.43 MM.

This economic data was used to calculate the required selling price (RSP) of the electric power from this plant. Using the same economic assumptions shown in Table 5, the RSP of electricity is calculated to be $41.22 per megawatt hour (MWH). The increase in capacity factor has resulted in a decrease in the RSP of the power from $45.20 to $41.22 per MWH a decrease of nearly 9 percent. This illustrates the importance of gasifier reliability, availability and maintainability (RAM) in reducing the cost of power from IGCC plants.

In case 3, the case 1 configuration and increased capacity are maintained but the carbon utilization is increased from 95 percent to 98 percent. Therefore, it is assumed that 98 percent of the carbon in the coal feed is converted to synthesis gas in the gasifier, the remaining carbon reports to the slag. The material flows for selected streams are shown in

Table 6. Case 2: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	45
Gasification	130
Air Separation Unit	72
Acid Gas Removal	26
Sulfur Recovery	26
Gas Turbine	69
HRSG	35
Steam Turbine	37
Cooling/Feed Water Systems	35
Balance of Plant	78
Total Installed Cost	**553**
Home Office (8.4%)	46
Process Contingency (2%)	11
Project Contingency (15%)	92
Total Plant Cost	**702**
Non-depreciable Capital	24
Total Capital	**726**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	43.43
Cat/Chem Materials	9.40
Water	1.06
Operating and Maintenance Labor	9.70
Overhead/G&A	3.90
Administrative Labor	2.20
Local Taxes and Insurance	14.00
Solid Disposal	1.43
Gross Annual Operating Cost	85.12
By-product Credit	2.95
Net Annual Operating Cost	**82.17**

Net Power Output = 543 MW

RSP of Electricity (COE) = $41.22/MWH

Table 7 for case 3. This two train gasification plant processes 4,620 TPD of as-received coal to produce 541 MW of net power. Overall efficiency is thus 41 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 647 MW, 392 MW from the gas turbine and 255 MW from the steam turbine. Parasitic power required is estimated to be 106 MW with the largest user being the ASU at 60 MW.

Table 8 is a summary of the plant capital and operating and maintenance costs. In case 3, the total installed plant construction cost is reduced slightly from the base case to $545 million, and the total capital cost of the case 3 plant is $715 MM. The capital decrease is the result of using approximately 3 percent less coal compared to the base case because of the greater carbon utilization assumed in this case. Net plant power output is essentially the same as the base case at 541 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $80.43 MM. This is higher than the base case because of the increase in variable operating cost and fuel cost due to a greater capacity factor. Coal feedstock cost is lower than case 2 because of the greater carbon utilization assumed. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $42.14 MM. These improved assumptions result in a decrease in the RSP of the electric power from $41.22 in case 2 to $40.59 per MWH in case 3.

4.3 Case 4: Two-Stage Slurry Feed Gasification with 85 Percent Capacity and 98 Percent Carbon Utilization

Figure 3 shows a schematic of case 4. In this configuration a two-stage slurry feed coal gasification process is assumed to be used for the production of the synthesis gas from coal. This replaced the single stage slurry feed gasifier. In this gasification process, coal/water slurry is injected with oxygen into the first stage of the gasifier. Partial combustion of the coal maintains a temperature of about 2500ºF to produce raw fuel gas. The coal ash melts and flows from the bottom of the gasifier as slag. Additional coal/water slurry is injected into the second stage and the coal undergoes devolatilization, pyrolysis and partial gasification to cool the raw gas formed in the first stage. The gas is further cooled in a waste heat boiler (WHB) to produce high pressure steam and entrained char particles are recovered in candle filters and recycled to the first gasifier stage. The raw gas is then sent to a water scrub to remove ammonia, chloride, cyanide and residual particles and then to a COS hydrolysis unit. After further cooling, the raw gas is sent to an activated carbon absorber for mercury removal. The cold gas is sent to a conventional amine-based acid gas removal system and the hydrogen sulfide is converted into elemental sulfur in a Claus/SCOT unit. The clean fuel gas is then sent to the gas turbine combustor. Gas turbine exit gas is sent to the HRSG for steam generation and the high pressure steam generated is sent to the steam turbine for power generation. The greater capacity factor (85 percent) and the carbon utilization (98 percent) are maintained in this case.

Table 7: Case 3 Single Stage Slurry Feed 85 Percent Cap/98 Percent Carbon Utilization
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8
	Gasifier Output	Cooler/COS Exit	Fuel to Gas Turbine	Air to Gas Turbine	Feed to HRSG	Exit From HRSG	Air to ASU	Oxygen to Gasifier
CH4	1	1	1					
H2O	8,994	2,943	0		11,088	11,088		
H2	11,221	11,221	11,080					
CO	16,117	16,117	15,978					
CO2	3,928	3,928	3,703		19,682	19,682		
O2	0	0	0	52,133	29,101	29,101	9,690	9,690
N2	755	755	749	197,794	198,543	198,543	36,764	510
H2S	302	302	NIL		NIL	NIL		
NH3	TRACE	NIL	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		
Hg	TRACE	TRACE	TRACE		TRACE	TRACE		
COS	TRACE	TRACE	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		
Total	41,317	35,266	31,512	249,927	258,414	258,414	46,455	10,200
Temperature, F	2,600	265	550	763	1,072	260	686	302
Pressure, Psia	425	348	208	208	15	15	196	446

Power Summary, MW			Coal Input, T/Day AR		4,620
Production:	MW				
Steam Turbine	255				
Gas Turbine	392		Gasifier Input,	1000#/Hr	
Total	647		Coal	305	
			Ash	37	
Plant Use:			H2O (coal)	43	
ASU	60		H2O (slurry)	172	
Oxygen Compressio	14		O2	310	
Miscellaneous	32				
Total	106				
			Efficiency	41.12%	
Net Output	541				

Table 8. Case 3: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary	$MM (2002)	Operating and Maintenance Cost Summary	$MM (2002)
Coal Handling/Feeding	44	Coal ($29.40/Ton AR)	42.14
Gasification	127	Cat/Chem Materials	9.30
Air Separation Unit	71	Water	1.06
Acid Gas Removal	26	Operating and Maintenance Labor	9.60
Sulfur Recovery	25	Overhead/G&A	3.80
Gas Turbine	69	Administrative Labor	2.20
HRSG	35	Local Taxes and Insurance	13.80
Steam Turbine	37	Solid Disposal	1.39
Cooling/Feed Water Systems	35	Gross Annual Operating Cost	83.29
Balance of Plant	76	By-product Credit	2.86
Total Installed Cost	**545**	**Net Annual Operating Cost**	**80.43**
Home Office (8.4%)	46		
Process Contingency (2%)	11		
Project Contingency (15%)	90		
Total Plant Cost	**692**	**Net Power Output = 541 MW**	
Non-depreciable Capital	23		
Total Capital	**715**	**RSP of Electricity (COE) = $40.59/MWH**	

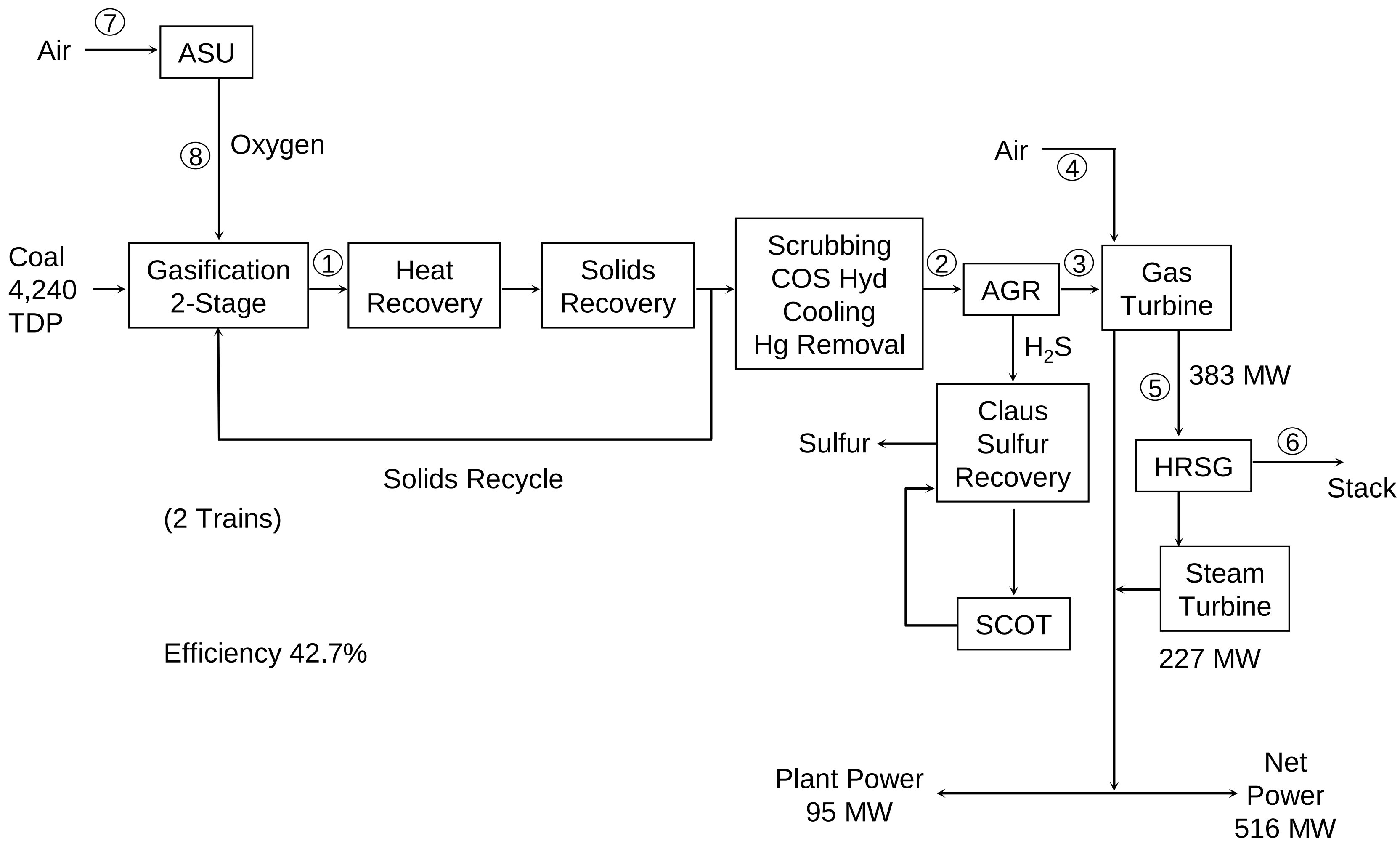


Figure 3. Case 4: Two Stage, Slurry Feed Gasification

Table 9 summarizes the process flows for selected streams for the case 4 IGCC plant configuration. This two train gasification plant processes 4,240 TPD of as-received coal to produce 516 MW of net power. Overall efficiency is thus 42.7 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 610 MW, 383 MW from the gas turbine and 227 MW from the steam turbine. Parasitic power required is estimated to be 95 MW.

Table 10 is a summary of the plant capital and operating and maintenance costs for case 4. The total installed plant construction cost is estimated to be $504 MM and the total capital cost of the case 4 plant is $662 MM. Excluding non-depreciable capital this is an investment cost of $1,241/kW. The capital decrease is primarily the result of using a more efficient gasification system that reduces both the coal and the gasification oxygen requirement. Approximately 5 percent less coal is needed for a comparable net power output compared to the base case. Net plant power output is less than the base case at 516 MW. Net annual operating and maintenance costs, after by-product credit reduction, are estimated to be $74.10 MM. Coal feedstock cost is lower than cases 2 and 3 because of the higher gasifier efficiency. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $38.69 MM. These improved assumptions result in a decrease in the RSP of the electric power from $40.59 per MWH in case 3 to $39.38 per MWH.

4.4 Case 5: Dry Feed Gasification with 85 Percent Capacity and 98 Percent Carbon Utilization

Figure 4 shows a schematic of case 5. In this configuration, a single-stage dry-feed gasification process is assumed to be used for the production of the synthesis gas from coal. This replaced the two stage slurry feed gasifier used in case 4. Unlike the previous gasifier systems where the coal is fed as water slurry, in this gasifier the as-received coal containing about 11 percent moisture is fed directly into the gasifier through pressurized lock hoppers. Nitrogen from the ASU is used to transport the dry coal from the pressurized lock hoppers into the gasifier in dense phase flow. There it is gasified in the presence of oxygen to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature, by recycling cool product gas, before passing into the waste heat boiler (WHB) where high pressure steam is produced. The raw gas is then sent to a water scrub to remove chloride, ammonia, cyanide and residual particles and then to a carbonyl sulfide (COS) hydrolysis unit. After further cooling, the raw gas is sent to an activated carbon absorber for mercury removal. The cold gas is sent to a conventional amine-based acid gas removal system and the hydrogen sulfide is converted into elemental sulfur in a Claus/SCOT unit. The clean fuel gas is then sent to the gas turbine combustor. Gas turbine exit gas is sent to the HRSG for steam generation, and the steam is sent to the steam turbine. The greater capacity factor (85 percent) and the carbon utilization (98 percent) are maintained in this case.

Table 9: Case 4 Two Stage Slurry Feed 85 Percent Cap/98 Percent Carbon Util
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8
	Gasifier Output	Cooler/COS Exit	Fuel to Gas Turbine	Air to Gas Turbine	Feed to HRSG	HRSG Exit	Air to ASU	Oxygen to Gasifier
CH4	24	24	24					
H2O	4,413	2,476	0		11,753	11,753		
H2	11,847	11,847	11,699					
CO	15,668	15,668	15,535					
CO2	2,711	2,711	2,556		18,115	18,115		
O2	0	0	0	53,136	31,977	31,977	7,641	7,641
N2	618	618	613	201,598	202,211	202,211	28,989	402
H2S	277	277	NIL		NIL	NIL		
NH3	0	0	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		
Hg	TRACE	TRACE	NIL		NIL	NIL		
COS	TRACE	TRACE	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		
Total	35,558	33,621	30,427	254,734	264,055	264,055	36,630	8,043
Temperature, F	2,200	265	550	755	1,057	260	686	393
Pressure, Psia	425	348	208	208	15	15	196	446

Power Summary, MW			Coal Input, T/Day AR		4,241
Production:	MW				
Steam Turbine	227				
Gas Turbine	383		Gasifier Inpu	1000#/Hr	
Total	610		Coal	280	
			Ash	34	
Plant Use:			H2O (coal)	39	
ASU	47		H2O (slurry)	118	
Oxygen Compressio	12		O2	245	
Miscellaneous	35				
Total	95				
			Efficiency	42.70%	
Net Output	516				

Table 10. Case 4: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	42
Gasification	121
Air Separation Unit	56
Acid Gas Removal	23
Sulfur Recovery	22
Gas Turbine	67
HRSG	32
Steam Turbine	34
Cooling/Feed Water Systems	32
Balance of Plant	75
Total Installed Cost	**504**
Home Office (8.4%)	42
Process Contingency (2%)	10
Project Contingency (15%)	84
Total Plant Cost	**640**
Non-depreciable Capital	22
Total Capital	**662**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	38.69
Cat/Chem Materials	8.60
Water	0.95
Operating and Maintenance Labor	8.84
Overhead/G&A	3.54
Administrative Labor	2.00
Local Taxes and Insurance	12.80
Solid Disposal	1.30
Gross Annual Operating Cost	76.72
By-product Credit	2.62
Net Annual Operating Cost	**74.10**

Net Power Output = 516 MW

RSP of Electricity (COE) = $39.38/MWH

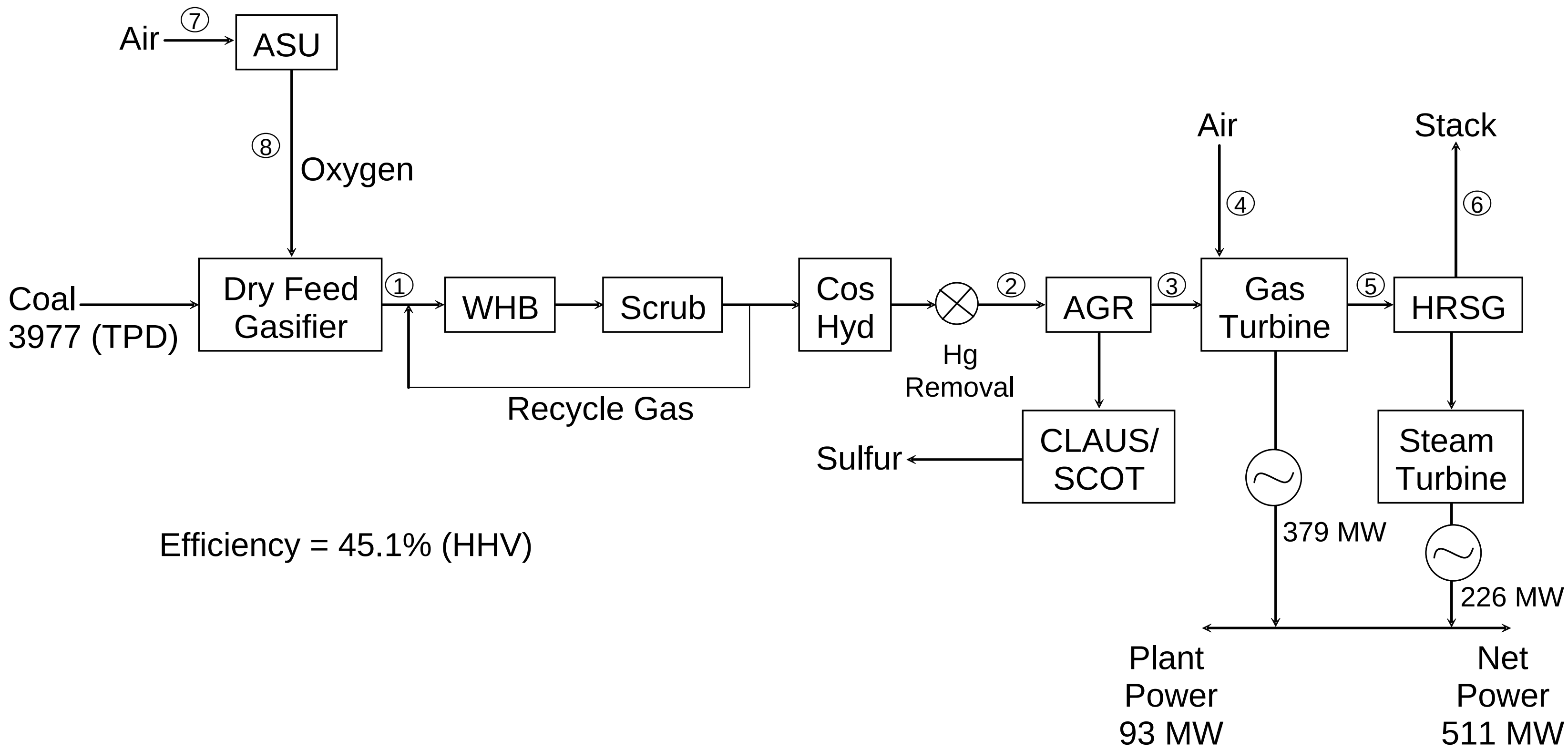


Figure 4. Case 5: Dry Feed Gasifiers/FB Turbine

Table 11 summarizes the process flows for selected streams for the case 5 IGCC plant configuration. This two train, dry feed gasification plant processes 3,977 TPD of as-received coal to produce 511 MW of net power. Overall efficiency is thus 45.1 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 604 MW, 379 MW from the gas turbine and 226 MW from the steam turbine. Parasitic power required is estimated to be 93 MW.

Table 12 is a summary of the plant capital and operating and maintenance costs for case 5. In case 5, the total installed plant construction cost is estimated to be $490 MM and the total capital cost of the case 4 plant is $643 MM. Excluding non-depreciable capital this is an investment cost of $1,216/kW. This capital cost is lower than case 4 primarily because overall plant efficiency is higher so coal requirement is reduced. Net plant power output is less than the base case at 511 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $70.73 MM. At $29.40 per ton ($1.26 per million Btu HHV basis) the coal feed cost is $36.30 MM. These improved assumptions result in a decrease in the RSP of the electric power from $39.38 per MWH in case 4 to $38.33 per MWH.

4.5 Case 6: Dry Feed Gasification with 85 Percent Capacity, 98 Percent Carbon Utilization, and FB-Gas Turbine

Case 6 is identical in configuration to the previous case 5 except that an advanced FB-frame gas turbine is assumed in place of the F frame gas turbine used in all the prior analyses. Therefore, this configuration uses a single-stage dry-feed gasification process for the production of the synthesis gas from coal. The coal is gasified in the presence of oxygen to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature, by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, cyanide, chloride and residual particles and then to a carbonyl sulfide (COS) hydrolysis unit. After further cooling, the raw gas is sent to an activated carbon absorber for mercury removal. The cold gas is sent to a conventional amine-based acid gas removal system and the hydrogen sulfide is converted into elemental sulfur in a Claus/SCOT unit. The clean fuel gas is then sent to the combustor of the FB-frame gas turbine for power generation. Because GE has not, as yet, run the FB-frame gas turbine on synthesis gas, assumptions had to be made regarding the expected performance. It was assumed that the combustor flame temperature was 2600ºF and the compression ratio was 16:1 (compared to 14:1 and 2450F for the F-frame turbine). The molar gas flows to both the F- and FB-frame turbines were adjusted to be very similar in this analysis. General Electric indicated that they expect an overall efficiency advantage of about 3 percent for the FB-turbine compared to the current F-frame version. Gas turbine exit

Table 11: Case 5 Dry Feed 85 Percent Cap/98 Percent Carbon Utilization
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8
	Gasifier Output	Cooler/COS Exit	Fuel to Gas Turbine	Air to Gas Turbine	Feed to HRSG	HRSG Exit	Air to ASU	Oxygen to Gasifier
CH_4	38	38	38					
H_2O	333	2,031	0		8,734	8,734		
H_2	8,767	8,767	8,653					
CO	17,003	17,003	16,850					
CO_2	216	216	203		17,091	17,091		
O_2	0	0	0	53,508	33,188	33,188	7,150	7,150
N_2	1,985	1,985	1,969	203,008	204,977	204,977	27,127	1,607
H_2S	260	260	NIL		NIL	NIL		
NH_3	TRACE	NIL	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		
Hg	TRACE	TRACE	NIL		NIL	NIL		
COS	TRACE	TRACE	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		
Total	28,601	30,299	27,713	256,516	263,991	263,991	34,276	8,757
Temperature, F	2,500	265	550	755	1,051	260	686	401
Pressure, Psia	425	348	208	208	15	15	196	467

Power Summary, MW		Coal Input, T/Day AR		3,977
Production:	MW			
Steam Turbine	226			
Gas Turbine	379	Gasifier Input,	1000#/Hr	
Total	604	Coal	262	
		Ash	32	
Plant Use:		H_2O	37	
ASU	44	O_2	229	
Oxygen Compressio	14			
Miscellaneous	35			
Total	93			
		Efficiency	45.14%	
Net Output	511			

Table 12. Case 5 Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	40
Gasification	114
Air Separation Unit	61
Acid Gas Removal	20
Sulfur Recovery	19
Gas Turbine	67
HRSG	32
Steam Turbine	34
Cooling/Feed Water Systems	31
Balance of Plant	72
Total Installed Cost	**490**
Home Office (8.4%)	41
Process Contingency (2%)	10
Project Contingency (15%)	81
Total Plant Cost	**622**
Non-depreciable Capital	21
Total Capital	**643**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	36.30
Cat/Chem Materials	8.32
Water	0.95
Operating and Maintenance Labor	8.60
Overhead/G&A	3.44
Administrative Labor	1.95
Local Taxes and Insurance	12.43
Solid Disposal	1.20
Gross Annual Operating Cost	73.20
By-product Credit	2.46
Net Annual Operating Cost	**70.73**

Net Power Output = 511 MW

RSP of Electricity (COE) = $38.33/MWH

gas is sent to the HRSG for steam generation, and the steam is sent to the steam turbine. The greater capacity factor (85 percent) and the carbon utilization (98 percent) are maintained in this case.

Table 13 summarizes the process flows for selected streams for the case 6 IGCC plant configuration. This two train gasification plant processes 4,316 TPD of as-received coal to produce 574 MW of net power. Overall efficiency is thus 46.7 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 673 MW, 427 MW from the gas turbine and 246 MW from the steam turbine. Parasitic power required is estimated to be 99 MW with the largest user being the ASU at 48 MW.

Table 14 is a summary of the plant capital and operating and maintenance costs for case 6. In case 6, the total installed plant construction cost is estimated to be $520 MM and the total capital cost of the case 4 plant is $683 MM. Excluding non-depreciable capital this is an investment cost of $1,149/kW. This capital cost is lower than case 5 primarily because overall plant efficiency is higher. Net plant power output is greater than case 5 at 574 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $75.85 MM. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $39.37 MM. In this case more coal is fed to the plant compared to case 5. These improved assumptions result in a decrease in the RSP of the electric power from $38.33 per MWH in case 5 to $36.40 per MWH.

4.6 Case 7: Dry Feed Gasification with 85 Percent Capacity, 98 Percent Carbon Utilization, FB-Gas Turbines, and SCOHS Gas Cleaning

Case 7 assumes the same dry feed gasification system for production of raw synthesis gas as case 6 but a warm gas cleanup (WGCU) process is used in place of the conventional amine system that was used in all of the previous 6 cases. The FB-frame gas turbine was also assumed in this case. The WGCU process selected was the Selective Catalytic Oxidation of Hydrogen Sulfide (SCOHS) Process.[4] This process has yet to be proven in commercial practice. The SCOHS Process operates by the selective oxidation of H_2S to sulfur. The oxidant is air injected directly into the synthesis gas stream. The sulfur product can then be condensed and removed from the reactor. The SCOHS reactor configuration selected for this analysis was the monolithic catalyst bed reactor system. This uses a carbon fiber based porous carbon monolithic catalyst to continually catalyze the H_2S oxidation and produce the liquid sulfur in one reactor with no regeneration stage. Compressed air at 400 percent of stoichiometric is used as the oxidant and this is mixed with the synthesis gas at a temperature of about 275ºF. The elemental sulfur produced flows by gravity to the bottom of the reactor where it is removed. The stoichiometry can be written:

$$H_2S + 1/2O_2 = S + H_2O$$

Table 13: Case 6 Dry Feed 85 Percent Cap/98 Percent Carbon Utilization (FB Turbine)
Selected Flows, Moles/Hour

	1 Gasifier Output	2 Cooler/COS Exit	3 Fuel to Gas Turbine	4 Air to Gas Turbine	5 Feed to HRSG	6 HRSG Exit	7 Air to ASU	8 Oxygen to Gasifier
CH4	41	41	41					
H2O	361	2,204	0		9,485	9,485		
H2	9,515	9,515	9,397					
CO	18,454	18,454	18,299					
CO2	234	234	221		18,561	18,561		
O2	0	0	0	53,392	31,330	31,330	7,760	7,760
N2	2,154	2,154	2,138	202,568	204,706	204,706	29,441	1,744
H2S	282	282	NIL		NIL	NIL		
NH3	TRACE	NIL	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		
Hg	TRACE	TRACE	NIL		NIL	NIL		
COS	TRACE	TRACE	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		
Total	31,042	32,885	30,097	255,960	264,083	264,083	37,201	9,504
Temperature, F	2,500	265	550	799	1,100	260	686	401
Pressure, Psia	425	348	208	208	15	15	196	467

Power Summary, MW		Coal Input, T/Day AR	4,316
Production:	MW		
Steam Turbine	246		
Gas Turbine	427	Gasifier Inpu	1000#/Hr
Total	673	Coal	285
		Ash	35
Plant Use:		H2O	40
ASU	48	O2	248
Oxygen Compressio	15		
N2 Compression	14		
MIscellaneous	21		
Total	99		
		Efficiency	46.69%
Net Output	574		

Table 14. Case 6: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	43
Gasification	123
Air Separation Unit	66
Acid Gas Removal	21
Sulfur Recovery	21
Gas Turbine	67
HRSG	34
Steam Turbine	36
Cooling/Feed Water Systems	33
Balance of Plant	76
Total Installed Cost	**520**
Home Office (8.4%)	44
Process Contingency (2%)	10
Project Contingency (15%)	86
Total Plant Cost	**660**
Non-depreciable Capital	23
Total Capital	**683**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	39.37
Cat/Chem Materials	8.84
Water	1.00
Operating and Maintenance Labor	9.12
Overhead/G&A	3.65
Administrative Labor	2.07
Local Taxes and Insurance	13.20
Solid Disposal	1.30
Gross Annual Operating Cost	78.55
By-product Credit	2.70
Net Annual Operating Cost	**75.85**

Net Power Output = 574 MW

RSP of Electricity (COE) = $36.40/MWH

Figure 5 shows the schematic for case 7. This configuration uses a single-stage dry-feed gasification process for the production of the synthesis gas from coal. The coal is gasified in the presence of oxygen to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature, by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 275ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to the SCOHS unit where the hydrogen sulfide is converted into elemental sulfur in the single monolithic reactor system. Because this unit recovers the sulfur, the Claus/SCOT units are not required. The clean fuel gas is then sent to the combustor of the FB-frame gas turbine for power generation. Gas-turbine exit gas is sent to the HRSG for steam generation and the steam is sent to the steam turbine. The greater capacity factor (85 percent) and the carbon utilization (98 percent) are maintained in this case.

Table 15 summarizes the process flows for selected streams for the case 7 IGCC plant configuration. This two train gasification plant processes 4,215 TPD of as-received coal to produce 575 MW of net power. Overall efficiency is thus 47.9 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 653 MW, 429 MW from the gas turbine and 244 MW from the steam turbine. Parasitic power required is estimated to be 97 MW with the largest user being the ASU at 47 MW.

Table 16 is a summary of the plant capital and operating and maintenance costs for case 7. In case 7, the total installed plant construction cost is estimated to be $493 MM and the total capital cost of the case 7 plant is $646 MM. Excluding non-depreciable capital, this is an investment cost of $1,086/kW. This capital cost is lower than case 6 primarily because of the elimination of the sulfur recovery units. Net plant power output is the same as case 6 at 575 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $72.96 MM. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $38.45 MM. These improved assumptions result in a decrease in the RSP of the electric power from $36.40 per MWH in case 6 to $34.63 per MWH.

4.7 Case 8: Dry Feed Gasification with 85 Percent Capacity, 98 Percent Carbon Utilization, FB-Gas Turbines, SCOHS Gas Cleaning, and ITM for Air Separation

In case 8, the potential impact of replacing the cryogenic ASU by an ITM reactor is investigated. The heart of the ITM reactor is essentially a ceramic perovskite type material that, at high temperatures, allows the passage of oxygen ions across the ceramic membrane.

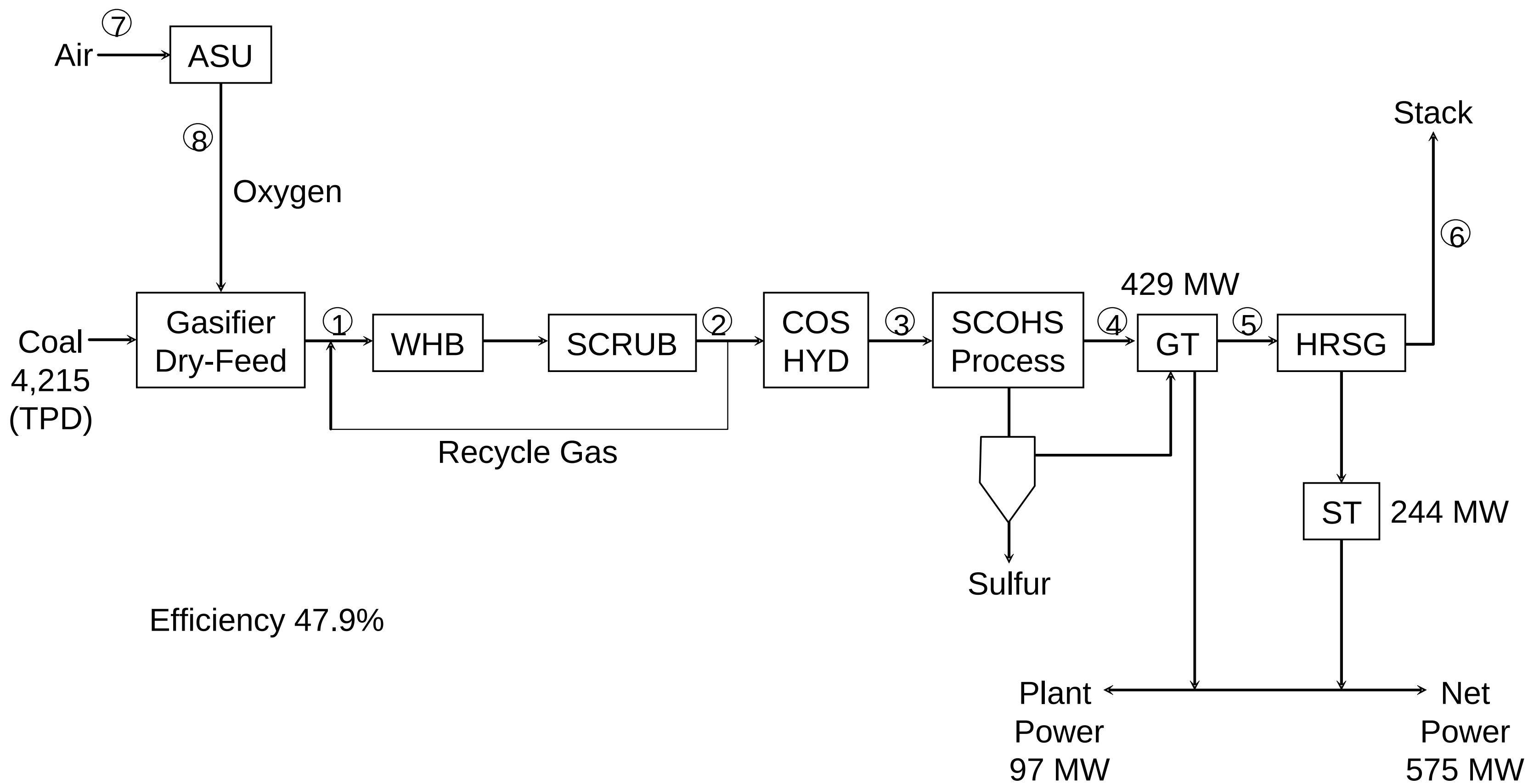


Figure 5. Case 7: Dry Feed/FB Turbine/SCOHS

Table 15: Case 7 Dry Feed 85 Percent Cap/98 Percent Carbon Util/FB/SCOHS

Selected Flows, Moles/Hour

	1 Gasifier Output	2 Scrubber Exit	3 COS/HYD Exit	4 SCOHS Exit	5 Feed to HRSG	6 HRSG EXIT	7 Air to ASU	8 Oxygen to Gasifier
CH4	41	41	41	41				
H2O	353	3,074	3,074	3,349	12,721	12,721		
H2	9,291	9,291	9,291	9,291				
CO	18,020	18,020	18,020	18,020				
CO2	229	229	229	229	18,289	18,289		
O2	0	0	0	278	31,399	31,399	7,577	7,577
N2	2,103	2,103	2,103	3,669	201,591	201,591	28,748	1,703
H2S	275	275	275	0				
NH3	TRACE	NIL	NIL	NIL	NIL	NIL		
HCN	TRACE	TRACE	NIL	NIL	NIL	NIL		
Hg	TRACE	TRACE	NIL	NIL	NIL	NIL		
COS	TRACE	TRACE	NIL	NIL	NIL	NIL		
HCl	TRACE	TRACE	NIL	NIL	NIL	NIL		
PM	TRACE	TRACE	NIL	NIL	NIL	NIL		
Total	42,045	33,032	33,032	34,876	264,000	18,289	36,325	9,280
Temperature, F	2,500	259	259	259	1,102	260	686	401
Pressure, Psia	425	366	348	404	15	15	196	467

Power Summary, MW		Coal Input, T/Day AR		4,215
Production:	MW			
Steam Turbine	244			
Gas Turbine	429	Gasifier Inpu	1000#/Hr	
Total	672	Coal	278	
		Ash	34	
Plant Use:		H2O	39	
ASU	47	O2	242	
Oxygen Compressio	14			
N2 Compression	14			
MIscellaneous	21			
Total	97			
		Efficiency	47.9%	
Net Output	575			

Table 16. Case 7: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	42
Gasification	120
Air Separation Unit	65
Acid Gas Removal (incl. COS Hyd)	21
Gas Turbine	67
HRSG	34
Steam Turbine	36
Cooling/Feed Water Systems	33
Balance of Plant	75
Total Installed Cost	**493**
Home Office (8.4%)	41
Process Contingency (2%)	10
Project Contingency (15%)	81
Total Plant Cost	**625**
Non-depreciable Capital	21
Total Capital	**646**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	38.45
Cat/Chem Materials	8.36
Water	0.96
Operating and Maintenance Labor	8.63
Overhead/G&A	3.45
Administrative Labor	1.96
Local Taxes and Insurance	12.49
Solid Disposal	1.27
Gross Annual Operating Cost	75.57
By-product Credit	2.61
Net Annual Operating Cost	**72.96**

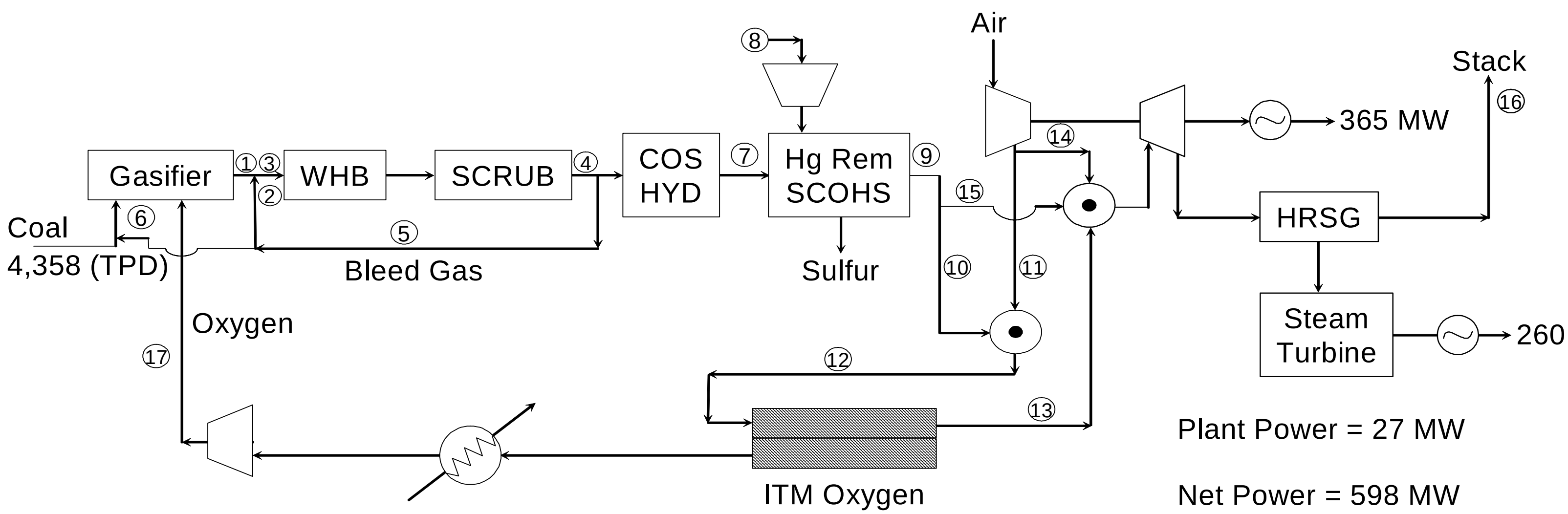
Net Power Output = 575 MW

RSP of Electricity (COE) = $34.63/MWH

These ions recombine to form oxygen molecules on the other side of the membrane. In this manner, the oxygen is separated from the nitrogen in the air to produce 100 percent purity oxygen. By replacing the cryogenic ASU with the ITM system, it is expected that both capital costs and power requirements will be significantly reduced.

Figure 6 shows the schematic for case 8. The clean coal-derived synthesis gas is produced in almost the same way as it is produced in the previous case 7. The coal is gasified in the presence of oxygen in a single stage dry feed gasifier to produce the raw fuel gas. However, in this case, there is no source of nitrogen because the cryogenic ASU unit has been replaced by the ITM system. Therefore, the coal is dry fed in dense phase flow using cooled synthesis gas. The raw fuel gas is cooled below the ash fusion temperature by recycling cool product gas (bleed gas on Figure 6), before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, chloride, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 275ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to the SCOHS unit that was described earlier. Because this unit recovers the sulfur, the Claus/SCOT units are not required. The clean fuel gas stream is then split. Some of the syngas is sent directly to the combustor of the FB-frame gas turbine for power generation and the remainder of the syngas is sent to a combustor whose function is to preheat the compressed air necessary for the ITM reactor. The ITM reactor operates at about 1,650ºF. Gas turbine exit gas is sent to the HRSG for steam generation and the HP steam is sent to the steam turbine. The greater capacity factor (85 percent) and the carbon utilization (98 percent) are maintained in this case.

The integration of the ITM reactor with the gas turbine is an important part of the configuration. Integration of these two component systems has not yet been tested and additional RD&D will be necessary to prove this integrated concept and to determine if the gas turbine compressor and expander can be balanced and the combustors can be designed to handle these gas streams and to produce low NOx exit gas. Indeed, the ITM reactor itself is currently only in the R&D stage and no large scale modules has been produced. The concept analyzed here (shown in Figure 6) uses the compressor of the gas turbine to compress the ITM air and turbine combustor air to 16 atmospheres and then a clean synthesis gas fired combustor is used to heat this air to ITM reactor temperature. The synthesis gas combustor effluent containing sufficient oxygen for separation is fed directly to the ITM reactor where pure oxygen is separated. The oxygen depleted air exiting the ITM reactor at 1,650ºF is sent to the gas turbine combustor where it is combusted with clean synthesis gas and additional air. The pure oxygen stream exiting the ITM reactor is sent to heat recovery to produce steam and then compressed and sent to the coal gasifier.



Efficiency 48.3%

Figure 6. Case 8: ITM Oxygen/IGCC Integration

Table 17 summarizes the process flows for selected streams for the case 8 IGCC plant configuration. This two train gasification plant processes 4,358 TPD of as-received coal to produce 598 MW of net power. Overall efficiency is thus 48.3 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 85 percent. Total power generated is 625 MW, 365 MW from the gas turbine and 260 MW from the steam turbine. Parasitic power required is estimated to be only 27 MW because all the air to the ITM reactor is bled from the gas turbine compressor.

Table 18 is a summary of the plant capital and operating and maintenance costs for case 8. In case 8, the total installed plant construction cost is estimated to be $484 MM and the total capital cost of the case 8 plant is $635 MM. Excluding non-depreciable capital this is an investment cost of $1,027/kW. This capital cost is lower than case 7 primarily because of the reduction in the ASU cost. It is assumed that the ITM reactor is only 66 percent of the cost of a cryogenic unit of the same capacity. Net plant power output is greater than case 7 at 598 MW primarily because of the reduced power requirement of the ITM system. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $73.66 MM. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $39.75 MM. These improved assumptions result in a decrease in the RSP of the electric power from $34.63 per MWH in case 7 to $32.70 per MWH.

4.8 Case 9: Dry Feed Gasification with 90 Percent Capacity, 98 Percent Carbon Utilization, FB-Gas Turbines, SCOHS Gas Cleaning, and ITM for Air Separation

Case 9 has the same configuration as case 8 (see Figure 6). The only difference between case 8 and case 9 is that the capacity factor has been increased from 85 percent (that is the plant is producing power for 365*0.85 or 310 days of the year) to 90 percent or 328 days per year.

Table 19 is a summary of the plant capital and operating and maintenance costs. In case 9, the total installed plant construction cost is unchanged from case 8 at $484 million and the total capital cost of the case 9 plant is thus $635 MM. Net plant power output is the same as case 8 at 598 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $75.89 MM. This is higher than case 8 because of the increase in coal feed. Coal feedstock cost at $29.40 per ton ($1.26 per million Btu HHV basis) is $42.09 MM. Increasing the capacity factor to 90 percent results in a decrease in the RSP of the electric power from $32.70 per MWH in case 8 to $31.50 per MWH in case 9.

Table 17: Case 8 Dry Feed 85 Percent Cap/98 Percent Carbon Util/FB/SCOHS/ITM
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8	9
	Gasifier Output	Recycle Gas	Mixed Gas	Scrubber Exit	Bleed Gas (Dry)	Coal Feed Gas (Dry)	SCOHS Input	SCOHS Air	SCOHS Exit
CH_4	42	17	59	39	20	3	39		39
H_2O	412	0	412	1,796	0	0	1,796		1,796
H_2	10,289	4,093	14,382	9,563	4,819	726	9,563		9,563
CO	20,033	7,969	28,002	18,620	9,382	1,413	18,620		18,620
CO_2	268	107	375	249	126	19	249		249
O_2	0	0	0	0	0	0	0	529	397
N_2	277	110	387	257	130	20	257	2,007	2,264
H_2S	284	113	398	264	133	20	264		0
NH_3	TRACE			NIL					NIL
HCN	TRACE			TRACE					NIL
Hg	TRACE			TRACE					NIL
COS	TRACE			TRACE					NIL
HCl	TRACE			TRACE					NIL
PM	TRACE			TRACE					NIL
Total	31,605	12,409	44,015	30,790	14,609	2,200	30,790	2,535	32,928
Temperature, F	2,500	119	1900	233					387
Pressure, Psia	425	441	425	404					235
	10	11	12	13	14	15	16	17	
	ITM Heater	Air to	Heated	Depleted	Air To	Gas Turb	HRSG	Oxygen to	
SPECIE	Fuel	ITM	ITM Input	ITM Air	Gas Turb	Fuel	Exhaust	Gasifier	
CH_4	5		0	0		34	0		
H_20	267		1,518	1,518		1,793	11,703		
H_2	1240		0	0		8,323	0		
CO	2415		0	0		16,205	0		
CO_2	32		2,453	2,453		217	18,909		
O_2	51	12,274	10,487	2,622	40,285		30,391	7,865	
N_2	294	46,567	46,860	46,860	152,841	1,970	199,665	83	
H_2S	0		0	NIL		NIL	NIL		
NH_3				NIL		NIL	NIL		
HCN				NIL		NIL	NIL		
Hg				NIL		NIL	NIL		
COS				NIL		NIL	NIL		
HCl				NIL		NIL	NIL		
PM				NIL		NIL	NIL		
Total	4,305	58,840	61,318	53,453	193,125	28,542	260,666	7,948	
Temperature, F		796		1,652	796	387	260	445	
Pressure, Psia		235		247	235	404	15	467	

Power Summary, MW				Coal Input, T/Day AR		4,358
Production:		MW				
Steam Turbine		260				
Gas Turbine		365		Gasifier Inp	1000#/Hr	
Total		625		Coal	288	
				Ash	35	
Plant Use:				H_2O	40	
		MW		O_2	252	
ITM O_2 Compression		13				
Miscellaneous		14				
Total		27				
				Efficiency	48.3%	
	Net Output	598				

Capital Cost Summary	$MM (2002)
Coal Handling/Feeding	43
Gasification	125
Air Separation Unit (ITM)	44
Acid Gas Removal (incl. COS Hyd)	21
Gas Turbine	67
HRSG	36
Steam Turbine	38
Cooling/Feed Water Systems	34
Balance of Plant	76
Total Installed Cost	**484**
Home Office (8.4%)	40
Process Contingency (2%)	10
Project Contingency (15%)	80
Total Plant Cost	**614**
Non-depreciable Capital	21
Total Capital	**635**

Operating and Maintenance Cost Summary	$MM (2002)
Coal ($29.40/Ton AR)	39.75
Cat/Chem Materials	8.21
Water	1.00
Operating and Maintenance Labor	8.48
Overhead/G&A	3.40
Administrative Labor	1.92
Local Taxes and Insurance	12.27
Solid Disposal	1.31
Gross Annual Operating Cost	76.34
By-product Credit	2.68
Net Annual Operating Cost	**73.66**

Net Power Output = 598 MW

RSP of Electricity (COE) = $32.70/MWH

Table 19. Case 9: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	43
Gasification	125
Air Separation Unit (ITM)	44
Acid Gas Removal (incl. COS Hyd)	21
Gas Turbine	67
HRSG	36
Steam Turbine	38
Cooling/Feed Water Systems	34
Balance of Plant	76
Total Installed Cost	**484**
Home Office (8.4%)	40
Process Contingency (2%)	10
Project Contingency (15%)	80
Total Plant Cost	**614**
Non-depreciable Capital	21
Total Capital	**635**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	42.09
Cat/Chem Materials	8.21
Water	1.06
Operating and Maintenance Labor	8.48
Overhead/G&A	3.39
Administrative Labor	1.92
Local Taxes and Insurance	12.27
Solid Disposal	1.31
Gross Annual Operating Cost	78.73
By-product Credit	2.84
Net Annual Operating Cost	**75.89**

Net Power Output = 598 MW

RSP of Electricity (COE) = $31.50/MWH

4.9 Case 10: Dry Feed Gasification with 90 Percent Capacity, 98 Percent Carbon Utilization, H-Frame Gas Turbine, SCOHS Gas Cleaning, and ITM for Air Separation

In case 10 it is assumed that the H frame gas turbine is commercially available for use on synthesis gas in an IGCC configuration. The overall plant schematic for this case is identical to that of case 8 (see Figure 6). The flow rates and material balances are different, however, because of the larger size of the H-frame gas turbine. Previous plants had two gasification trains to produce synthesis gas for two F-frame Gas turbines. But, because of the larger H-turbine, case 10 is a single train plant with one gasifier and one gas turbine. It is assumed that the dry feed gasifier can process 3,100 TPD of coal in a single gasifier. The H-frame turbine is assumed to have a firing temperature of 2,650ºF and a compression ratio of 22:1.

In case 10, the clean coal-derived synthesis gas is produced in the same way as it is produced in the previous cases 8 and 9. The coal is gasified in the presence of oxygen in a single stage dry feed gasifier to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, chloride, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 275ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to the SCOHS unit. The Claus/SCOT units are not required. The clean fuel gas stream is then split. Some is sent to the combustor of the H frame gas turbine for power generation and the remainder is sent to a combustor whose function is to preheat the compressed air before it enters the ITM reactor. The ITM reactor operates at about 1,650ºF. Gas-turbine exit gas is sent to the HRSG for steam generation and the high pressure steam is sent to the steam turbine. The greater capacity factor (90 percent) and the carbon utilization (98 percent) are maintained in this case.

The oxygen depleted air exiting the ITM reactor at 1,650ºF is sent to the gas turbine combustor where it is combusted with clean synthesis gas. The pure oxygen stream exiting the ITM reactor is sent to heat recovery to produce steam and then compressed and sent to the coal gasifier.

Table 20 summarizes the process flows for selected streams for the case 10 IGCC plant configuration. This single train gasification plant processes 3,134 TPD of as-received coal to produce 451 MW of net power. Overall efficiency is thus 50.5 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 90 percent. Total power generated is 471 MW, 291 MW from the gas turbine, and 180 MW from the steam turbine. Parasitic power required is estimated to be only 20 MW because all the air to the ITM reactor is bled from the gas turbine compressor.

Table 20: Case 10 Dry Feed 90 Percent Cap/98 Percent Carbon Util/H-Turbine/SCOHS/ITM
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8	9
	Gasifier Output	Recycle Gas	Mixed Gas	Scrubber Exit	Bleed Gas	Coal Feed Gas (Dry)	SCOHS Input	SCOHS Air	SCOHS Exit
CH4	34	14	48	48	16	2	32		32
H2O	296	0	296	1,877	629	0	1,248		1,248
H2	7,391	2,939	10,330	10,330	3,460	521	6,870		6,870
CO	14,401	5,726	20,127	20,127	6,741	1,016	13,386		13,386
CO2	193	77	270	270	90	14	179		179
O2	0	0	0	0	0	0	0	380	285
N2	199	79	278	278	93	14	185	1,443	1,628
H2S	205	81	286	286	96	14	190		0
NH3	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL
HCN	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
Hg	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
COS	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
HCl	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
PM	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL
Total	22,720	8,915	31,635	33,215	11,125	1,581	22,090	1,823	23,628
Temperature, F	2,500	118	1900	237	237	500	237	786	390
Pressure, Psia	450	441	450	427	427	142	427	441	378
	10	11	12	13	14	15	16	17	
SPECIE	ITM Heater Fuel	Air to ITM	Heated ITM Input	Depleted ITM Air	Air To Gas Turb	Gas Turb Fuel	HRSG Exhaust	Oxygen to Gasifier	
CH4	4		0	0		28	0		
H2O	160		929	929		1,279	8,372		
H2	762		0	0		6,108	0		
CO	1485		0	0		11,901	0		
CO2	20		1,508	1,508		159	13,597		
O2	32	8,638	7,539	1,885	22,705		15,402	5,654	
N2	181	32,773	32,953	32,953	86,141	1,447	119,098	60	
H2S	NIL		NIL	NIL		NIL	NIL		
NH3	NIL		NIL	NIL		NIL	NIL		
HCN	NIL		NIL	NIL		NIL	NIL		
Hg	NIL		NIL	NIL		NIL	NIL		
COS	NIL		NIL	NIL		NIL	NIL		
HCl	NIL		NIL	NIL		NIL	NIL		
PM	NIL		NIL	NIL		NIL	NIL		
Total	2,642	41,411	42,929	37,275	108,845	20,922	156,469	5,714	
Temperature, F	390	911	1,652	1,652	911	390	260	464	
Pressure, Psia	378	331	325	318	331	378	15	540	

Power Summary, MW				Coal Input, T/Day AR		3,134
Production:		MW				
Steam Turbine		180				
Gas Turbine		291		Gasifier Inp	1000#/Hr	
Total		471		Coal	207	
				Ash	25	
Plant Use:				H2O	29	
		MW		O2	181	
ITM O2 Compression		10				
Miscellaneous		10				
Total		20				
				Efficiency	50.5%	
	Net Output	451				

Table 21 is a summary of the plant capital and operating and maintenance costs for case 10. In case 10, the total installed plant construction cost is estimated to be $338 MM and the total capital cost of the case 10 plant is $445 MM. Excluding non-depreciable capital this is an investment cost of $951/kW. This capital cost is lower than case 9 primarily because this is a smaller plant with only one train of gasification and one gas turbine train. Net plant power output is the less than case 9 at 451 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $54.40 MM. At $29.40 per ton ($1.26 per million Btu HHV basis) the coal feed cost is $30.27 MM. These improved assumptions result in a decrease in the RSP of the electric power from $31.50 per MWH in case 9 to $29.60 per MWH.

4.10 Case 11: Dry Feed Gasification with 90 Percent Capacity, 98 Percent Carbon Utilization, F-Type Gas Turbine, SCOHS Gas Cleaning, ITM for Air Separation, and SOFC

In case 11, SOFC stacks are assumed to be available to act as the topping cycle before the gas turbine in an IGCC configuration. SOFCs are currently under development worldwide. A 100 kW SOFC cogeneration system supplied by Siemens Westinghouse operated in the Netherlands for over 16,000 hours. The system has a peak power of ~140 kW, typically feeding 109 kW into the local grid and 64 kW of hot water into the local district heating system, and has an electrical efficiency of 46 percent. In 2001, the system was moved from the Netherlands to a site in Essen, Germany and has operated for an additional 3700+ hours, for a total of 20,000+ hours. An SOFC/gas turbine hybrid system was delivered to Southern California Edison for operation at the University of California, Irvine's National Fuel Cell Research Center. The hybrid system includes a pressurized SOFC module integrated with a micro turbine/generator. The system has a total output of 220 kW, with 200 kW from the SOFC and 20 from the micro turbine generator. This proof of concept unit has operated for 900+ hours and has demonstrated 53 percent electrical efficiency. It is expected that SOFC/GT hybrids should be capable of electrical efficiencies of 60-70 percent. Siemens Westinghouse is planning larger 500 kW SOFC/Hybrid systems in future demonstrations.[5]

Figure 7 shows the schematic for the integrated SOFC/IGCC configuration (case 11). The clean coal-derived synthesis gas is produced in the same way as it is produced in case 10. The coal is gasified in the presence of oxygen in a single stage dry feed gasifier to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, chloride, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 275ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to the SCOHS unit that was described earlier. Because this unit recovers the sulfur,

Table 21. Case 10: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	31
Gasification	70
Air Separation Unit (ITM)	39
Acid Gas Removal (incl. COS Hyd)	17
Gas Turbine	45
HRSG	22
Steam Turbine	27
Cooling/Feed Water Systems	26
Balance of Plant	61
Total Installed Cost	**338**
Home Office (8.4%)	28
Process Contingency (2%)	8
Project Contingency (15%)	56
Total Plant Cost	**430**
Non-depreciable Capital	15
Total Capital	**445**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	30.27
Cat/Chem Materials	6.09
Water	0.77
Operating and Maintenance Labor	5.94
Overhead/G&A	2.38
Administrative Labor	1.35
Local Taxes and Insurance	8.59
Solid Disposal	1.00
Gross Annual Operating Cost	56.39
By-product Credit	2.00
Net Annual Operating Cost	**54.39**

Net Power Output = 451 MW

RSP of Electricity (COE) = $29.60/MWH

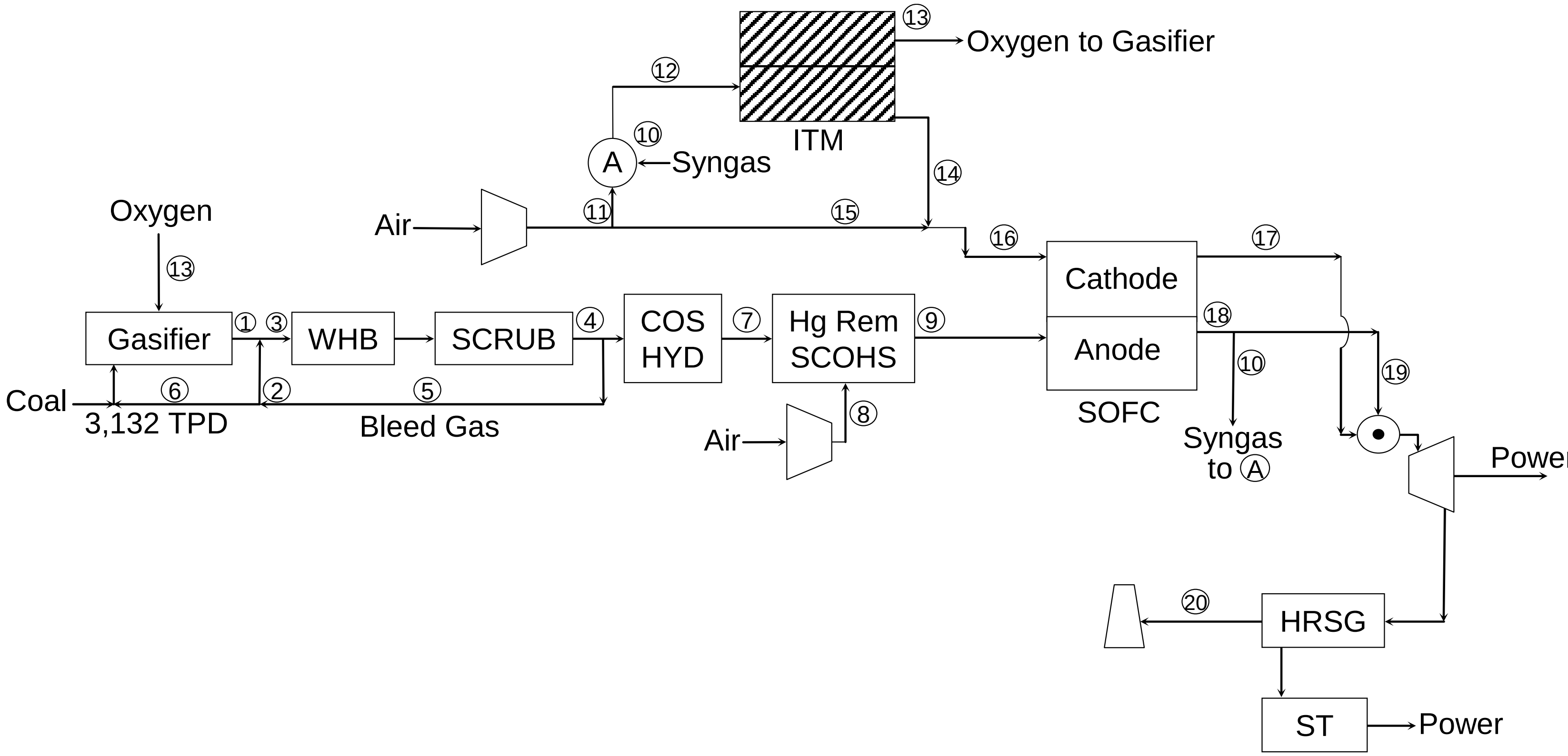


Figure 7. Case 11: Integration of ITM-0_2 with SOFC

the Claus/SCOT units are not required. The clean fuel gas is sent to the anode of the SOFC stacks.

In this analysis it is assumed that development of SOFCs has progressed to the point where large scale units operating at system pressure can be manufactured for use in large central power plants. This conceptual analysis assumes that there are enough SOFC stacks to generate 371 MW of power. It is assumed that 85 percent of the clean synthesis gas is converted into electrical energy in the fuel cell at an electrical efficiency of 60 percent. The fuel cell is assumed to operate at a temperature of 2000ºF and a pressure of about 16-atmospheres compatible with the gas turbine.

Referring to Figure 7, the exit gas from the SOFC anode is at 2000ºF and system pressure. This gas contains synthesis gas not converted in the SOFC. A portion of this gas is sent to combustor A for preheating the air to the ITM air separation unit. The residual stream is sent to the combustor of the gas turbine. The SOFC cathode exit gas is also sent to the gas turbine combustor. The gas turbine exit is sent to the HRSG for high pressure steam generation. This steam is used to generate additional power in the steam turbine. Air is compressed and heated in syngas-fired combustor A then sent to the ITM unit. The oxygen depleted air from the ITM unit is sent to the SOFC cathode along with additional compressed air. The oxygen from the ITM unit is sent to the coal gasifier. The greater capacity factor (90 percent) and the carbon utilization (98 percent) are maintained in this case.

Table 22 summarizes the process flows for selected streams for the case 11 IGCC plant configuration. This single train gasification plant processes 3,132 TPD of as-received coal to produce 579 MW of net power. Overall efficiency is thus 64.9 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 90 percent. Total power generated is 598 MW, 119 MW from the gas turbine, 371 MW from the SOFC, and 107 MW from the steam turbine. Parasitic power required is estimated to be only 19 MW because all the air to the ITM reactor is bled from the gas turbine compressor.

Table 23 is a summary of the plant capital and operating and maintenance costs for case 11. In case 11, the total installed plant construction cost is estimated to be $458 MM and the total capital cost of the case 11 plant is $600 MM. Excluding non-depreciable capital this is an investment cost of $1,002/kW. This capital per unit of power capacity cost is higher than case 10 because of the additional cost of the SOFC unit. It is assumed that the SOFC capital is $400/kW. Net plant power output is greater than case 10 at 579 MW because of the contribution from the high efficiency SOFC as a topping cycle. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $62.66 MM. At $29.40 per ton ($1.26 per million Btu HHV basis) the coal feed cost is $30.25 MM. These improved assumptions result in a decrease in the RSP of the electric power from $29.6 per MWH in case 10 to $29.20 per MWH.

Table 22: Case 11 Dry Feed 90 Percent Cap/98 Percent Carbon Util/H/SCOHS/ITM/SOFC

Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8	9	10
	Gasifier Output	Recycle Gas	Mixed Gas	Scrubber Exit	Bleed Gas (Dry)	Coal Feed Gas (Dry)	SCOHS Input	SCOHS Air	Anode Fuel	ITM Heater Fuel
CH4	30	12	42	28	14	2	28		28	22
H2O	298	0	298	1,292	0	0	1,292		1,482	6026
H2	7,393	2,903	10,297	6,872	3,425	521	6,872		6,872	580
CO	14,396	5,653	20,049	13,381	6,668	1,015	13,381		13,381	1840
CO2	194	76	270	180	90	14	180		180	8882
O2	0	0	0	0	0	0	0	380	285	0
N2	199	78	277	185	92	14	185	1,442	1,627	1286
H2S	204	80	285	190	95	14	190		0	0
NH3	TRACE	NIL	TRACE	NIL	NIL	NIL	NIL		NIL	NIL
HCN	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	NIL
Hg	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	NIL
COS	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	NIL
HCl	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	NIL
PM	TRACE	NIL	TRACE	NIL	NIL	NIL	NIL		NIL	NIL
Total	22,714	8,802	31,517	22,128	10,383	1,581	22,128	1,822	23,855	18,636
Temp, F	2,500	97	1900	233	233	500	233	776	386	2000
Pres., Psia	425	441	425	404	404	142	347.6	235	403.8	348
							1			
	11	12	13	14	15	16	17	18	19	20
	Air to	Heated	Oxygen to	Depleated	Cathode	Cathode	Cathode	Anode	Turbine	HRSG
SPECIE	ITM	ITM Input	Gasifier	ITM Air	Air	Feed	Exit	Exit	Fuel	Exhaust
CH4		0		0		0	0	28	6	0
H2O		6,650		6,650		6,650	6,650	7621	1595	8,411
H2		0		0		0	0	733	153	0
CO		0		0		0	0	2327	487	0
CO2		10,745		10,745		10,745	10,745	11234	2352	13,589
O2	11,002	9,748	5,654	4,094	4,743	8,837	240	0	0	193
N2	41,743	43,029	60	43,029	17,993	61,023	61,023	1627	341	61,364
H2S		NIL		NIL		NIL	NIL	NIL	NIL	NIL
NH3		NIL		NIL		NIL	NIL	NIL	NIL	NIL
HCN		NIL		NIL		NIL	NIL	NIL	NIL	NIL
Hg		NIL		NIL		NIL	NIL	NIL	NIL	NIL
COS		NIL		NIL		NIL	NIL	NIL	NIL	NIL
HCl		NIL		NIL		NIL	NIL	NIL	NIL	NIL
PM		NIL		NIL		NIL	NIL	NIL	NIL	NIL
Total	52,745	70,172	5,713	64,518	22,736	87,254	78,657	23,570	4,934	83,557
Temp, F	776	1,652	538	1,652	776	1450	2,000	2000	2000	260
Pres., Psia	235	232.8	467	247.0	235.2	365.1	383.5	348	348	15

Power Summary, MW	Coal Input, T/Day AR	3,132	
Production:	MW		
Steam Turbine	107		
Gas Turbine	119	Gasifier Inpu	1000#/Hr
Fuel Cell	371	Coal	207
Total	598	Ash	25
		H2O	29
Plant Use:		O2	181
Oxygen Compression	12		
MIscellaneous	7		
Total	19		
		Efficiency	64.9%
Net Output	579		

Table 23. Case 11: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	31
Gasification	70
Air Separation Unit (ITM)	39
Acid Gas Removal (incl. COS Hyd)	22
Fuel Cell	149
Gas Turbine	31
HRSG	15
Steam Turbine	18
Cooling/Feed Water Systems	21
Balance of Plant	62
Total Installed Cost	**458**
Home Office (8.4%)	38
Process Contingency (2%)	9
Project Contingency (15%)	75
Total Plant Cost	**580**
Non-depreciable Capital	20
Total Capital	**600**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	30.25
Cat/Chem Materials	8.24
Water	0.50
Operating and Maintenance Labor	8.02
Overhead/G&A	3.21
Administrative Labor	1.82
Local Taxes and Insurance	11.62
Solid Disposal	1.00
Gross Annual Operating Cost	64.66
By-product Credit	2.00
Net Annual Operating Cost	**62.66**

Net Power Output = 579 MW

RSP of Electricity (COE) = $29.20/MWH

4.11 Case 11(60): Dry Feed Gasification with 90 Percent Capacity, 98 Percent Carbon Utilization, F-Type Gas Turbine, SCOHS Gas Cleaning, ITM for Air Separation, and SOFC Modified to 60 Percent Overall Efficiency

Case 11(60) is the same configuration as case 11. Case 11(60) was analyzed to determine the combination of fuel cell and combined cycle power necessary to achieve the overall 60 percent efficiency goal for year 2020. An overall efficiency of 60 percent (HHV) can be obtained by reducing the power contribution of the SOFC and increasing the power contribution from the gas and steam turbines. The conceptual plant configuration computer simulation of case 11 was iterated until the combination of fuel cell and turbine power achieved the desired overall plant efficiency.

Table 24 summarizes the process flows for selected streams for the case 11(60) IGCC plant configuration. This single train gasification plant processes 3,132 TPD of as-received coal to produce 535 MW of net power. Overall efficiency is thus 60 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 90 percent. Total power generated is 554 MW, 168 MW from the gas turbine, 252 MW from the SOFC, and 134 MW from the steam turbine. Parasitic power required is estimated to be only 19 MW because all the air to the ITM reactor is bled from the gas turbine compressor.

Table 25 is a summary of the plant capital and operating and maintenance costs for case 11(60). In case 11(60), the total installed plant construction cost is estimated to be $423 MM and the total capital cost of the case 11(60) plant is $555 MM. Excluding non-depreciable capital this is an investment cost of $1,002/kW. This capital per unit of power capacity cost is the same as case 11. The capital cost is lower than case 11 because the size of the SOFC unit has been reduced by about 32 percent compared to case 11. The SOFC, capital even at $400/kW, is almost twice as expensive as a gas turbine of comparable capacity. Net plant power output is less than case 11 at 535 MW because of the smaller contribution from the high efficiency SOFC. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $60.28 MM. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $30.25 MM. The resulting RSP of the electric power is $29.70 per MWH, slightly higher than in case 11.

Table 24: Case 11(60) Dry Feed 90 Percent Cap/98 Percent Carbon Util/H/SCOHS/ITM/SOFC
Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8	9	10
	Gasifier Output	Recycle Gas	Mixed Gas	Scrubber Exit	Bleed Gas (Dry)	Coal Feed Gas (Dry)	SCOHS Input	SCOHS Air	Anode Fuel	ITM Heater Fuel
CH4	30	12	42	28	14	2	28		22	16
H2O	298	0	298	1,292	0	0	1,292		1,141	3,972
H2	7,393	2,903	10,297	6,872	3,425	521	6,872		5,291	719
CO	14,396	5,653	20,049	13,381	6,668	1,015	13,381		10,303	2,135
CO2	194	76	270	180	90	14	180		139	5,480
O2	0	0	0	0	0	0	0	380	220	0
N2	199	78	277	185	92	14	185	1,442	1,253	914
H2S	204	80	285	190	95	14	190		0	0
NH3	TRACE	NIL	TRACE	NIL	NIL	NIL	NIL		NIL	
HCN	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	
Hg	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	
COS	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	
HCl	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL	
PM	TRACE	NIL	TRACE	NIL	NIL	NIL	NIL		NIL	
Total	22,714	8,802	31,517	22,128	10,383	1,581	22,128	1,822	18,369	13,235
Temp, F	2,500	97	1900	233	233	500	233	776	386	2,000
Pres., Psia	425	441	425	404	404	142	347.6	235	403.8	348

	11	12	13	14	15	16	17	18	19	20
SPECIE	Air to ITM	Heated ITM Input	Oxygen to Gasifier	Depleated ITM Air	Cathode Air	Cathode Feed	Cathode Exit	Anode Exit	Turbine Fuel	HRSG Exhaust
CH4		0		0		0	0	22	6	0
H2O		4,723		4,723		4,723	4,723	5,447	1475	0
H2		0		0		0	0	986	267	0
CO		0		0		0	0	2,928	793	0
CO2		7,631		7,631		7,631	7,631	7,514	2035	13,589
O2	18,039	10,280	5,654	4,626	1,469	6,095	254	0	0	3,956
N2	68,442	45,449	60	45,449	5,572	51,021	51,021	1,253	339	75,641
H2S		NIL		NIL		NIL	NIL	NIL	NIL	8,411
NH3		NIL		NIL		NIL	NIL	NIL	NIL	NIL
HCN		NIL		NIL		NIL	NIL	NIL	NIL	NIL
Hg		NIL		NIL		NIL	NIL	NIL	NIL	NIL
COS		NIL		NIL		NIL	NIL	NIL	NIL	NIL
HCl		NIL		NIL		NIL	NIL	NIL	NIL	NIL
PM		NIL		NIL		NIL	NIL	NIL	NIL	NIL
Total	86,481	68,082	5,713	62,428	7,040	69,469	63,628	18,149	4,914	101,598
Temp, F	776	1,652	538	1,652	776	1,573	2,000	2,000	2,000	260
Pres., Psia	235	232.8	467	247.0	235.2	365.1	383.5	348	348	15

Power Summary, MW	Coal Input, T/Day AR	3,132		
Production:	MW			
Steam Turbine	134			
Gas Turbine	168		Gasifier Inpu	1000#/Hr
Fuel Cell	252		Coal	207
Total	554		Ash	25
			H2O	29
Plant Use:			O2	181
Oxygen Compression	12			
MIscellaneous	7			
Total	19			
			Efficiency	60.0%
Net Output	535			

Table 25. Case 11(60): Capital and Operating and Maintenance Cost Summary

Capital Cost Summary	$MM (2002)	Operating and Maintenance Cost Summary	$MM (2002)
Coal Handling/Feeding	31	Coal ($29.40/Ton AR)	30.25
Gasification	70	Cat/Chem Materials	7.61
Air Separation Unit (ITM)	39	Water	0.60
Acid Gas Removal (incl. CoS Hyd)	22	Operating and Maintenance Labor	7.41
Fuel Cell	99	Overhead/G&A	3.00
Gas Turbine	36	Administrative Labor	1.68
HRSG	18	Local Taxes and Insurance	10.73
Steam Turbine	22	Solid Disposal	1.00
Cooling/Feed Water Systems	24	Gross Annual Operating Cost	62.28
Balance of Plant	62	By-product Credit	2.00
Total Installed Cost	**423**	**Net Annual Operating Cost**	**60.28**
Home Office (8.4%)	35		
Process Contingency (2%)	8		
Project Contingency (15%)	70		
Total Plant Cost	**536**	**Net Power Output = 536 MW**	
Non-depreciable Capital	19		
Total Capital	**555**	**RSP of Electricity (COE) = $29.70/MWH**	

5.0 Summary Analysis of Non-Carbon Capture Cases

Table 26 summarizes the key results from the computer simulated conceptual plant analyses of the twelve (12) non-carbon capture IGCC cases. Current IGCC technology (case 1) is estimated to have an overall efficiency of 40 percent (HHV) equivalent to a heat rate of 8,530 Btu/kWh. Capital is estimated to be $1,294/kW on a capacity basis. This is a two train plant with an output of 543 MW and a capacity factor of 75 percent. Using the consistent set of financial parameters listed in Table 5, the RSP of the electric power from this current plant is calculated to be $45.20/MWH. This RSP is called the cost of electricity (COE) in Table 26. Improvements to this current configuration include increasing the capacity factor to 85 percent and increasing the carbon utilization in the gasifier from 95 to 98 percent. These improvements are shown in case 3 (column 3 in Table 26). These improvements result in an increase in efficiency to 41.1 percent, a reduction in the capital to $1,279/kW, and a decrease in the COE to $40.60/MWH.

Case 4 estimates the impact of a change in coal gasifier type from slurry feed, single stage entrained to two-stage entrained. This change improves efficiency to 42.7 percent, reduces capital to $1,241/kW, and reduces the COE to $39.40/MWH. In case 5, the gasifier is changed to reflect a dry feed entrained type. This has a positive effect on efficiency increasing it to 45 percent, reduces the capital to $1,217/kW, and reduces the COE to $38.30/MWH.

Case 6 estimates the impact of substituting the more efficient FB frame gas turbine for the F-frame turbine. Efficiency is increased to 46.7 percent, capital is reduced to $1,149/kW, and the resulting COE is reduced to $36.40/MWH. In case 7, the impact of replacing the conventional cold gas cleaning (amine based) system with a medium temperature gas cleaning system is analyzed. The novel gas cleaning technology selected was the SCOHS system that is currently in the R&D phase. This improves the efficiency to 47.9 percent, reduces the capital to $1,086/kW, and reduces the COE to $34.60/MWH.

In case 8, the potential impact of replacing the cryogenic ASU with the ITM system was analyzed. The ITM technology is currently in the R&D phase but it was assumed that this R&D would be successful in developing a commercial scale unit. Replacing the ASU with the novel ITM system was estimated to increase the IGCC plant efficiency to 48.3 percent, reduce the capital to $1,027/kW, and reduce the COE to $32.70/MWH.

Case 8 is assumed to represent the technology status for commercialization by the year 2010 (see Figure 1). The DOE targets for year 2010 are an IGCC plant with an overall efficiency of 50 percent and a capital of $1,000/kW. This analysis shows that these targets have almost but not quite been achieved. The estimated overall efficiency of the case 8 plant is

Table 26. Summary: Bituminous Coal to Power (No Carbon Captured)

Case	1	2	3	4	5	6	7	8	9	10	11	11(60)
COE ($/MWH)	45.2	41.2	40.6	39.4	38.3	36.4	34.6	32.7	31.5	29.6	29.2	29.7
Capital ($MM)	702	702	692	640	622	660	625	614	614	430	580	536
Efficiency (%)	40.0	40.0	41.1	42.7	45.1	46.7	47.9	48.3	48.3	50.5	64.9	60
Output (MW)	543	543	541	516	511	574	575	598	598	451	579	535
Capital ($/kW)	1,294	1,294	1,279	1,241	1,217	1,149	1,086	1,027	1,027	953	1,002	1,002
Coal Feed (TPD)	4,761	5,396	4,620	4,241	3,977	4,316	4,215	4,358	4,614	3,134	3,132	3,132
Capacity (%)	75	85	85	85	85	85	85	85	90	90	90	90
Target Year								2010				2020
Target Cost ($/kW)								1000				900
Target Efficiency (% HHW)								50				60

48.3 percent (compared to 50 percent for the target) and the capital has been reduced to $1,027/kW (compared to $1,000/kW for the target). This analysis indicates that the efficiency target of 50 percent and the capital cost target of $1,000/kW could be achieved by incorporating the more efficient advanced H frame gas turbine technology into the IGCC plant (see case 10). However, the H frame technology running on synthesis gas is not expected to be commercially available until the year 2012 (see Figure 1).

Case 9 is the same as case 8 except that the capacity factor has increased to 90 percent. This results in a decrease in the COE to $31.50/MWH. Case 10 assumes the availability of the H-frame gas turbine and this more efficient machine increases the overall plant efficiency from coal to electricity to 50.5 percent. The capital cost is reduced to $953/kW and the COE is reduced to $29.60/MWH.

Case 11 assumes the integration of SOFC technology as a topping cycle before the gas turbine. Because it is assumed that the SOFC has an efficiency to electric power of 60 percent and the waste heat from the SOFC can be captured effectively, the impact on overall plant efficiency is significant. In this case, the efficiency is increased to 64.9 percent, the capital is $1,002/kW, and the COE is $29.2/MWH. The capital is higher than case 10 because of the incorporation of the SOFC units that are assumed to have a capital cost of $400/kW. This cost is almost twice as high as a comparable gas turbine cost. In case 11(60), the plant was designed to achieve an overall efficiency of 60 percent by adjusting the contribution of power from the fuel cell and the turbines. In this case, the overall efficiency was 60 percent, the capital was $1,002/kW, and the resulting COE was $29.7/MWH. Cases 11 and 11(60) therefore achieve the DOE efficiency target of 60 percent but do not quite match the capital cost target of $900/kW. To achieve this lower capital cost target requires the unit costs of the IGCC plant components to be lower. This would include reducing the capital cost of the SOFC units to below $400/kW.

Figures 8, 9, and 10 depict these estimated changes in COE, capital, and efficiency of IGCC systems with deployment of new technology as broad trend lines from the present until year 2020. The clear message is that there are potentially significant improvements that could result from continuing RD&D in advanced IGCC systems. These are estimated to be:

- Advanced technology can reduce COE by about 35 percent compared to current IGCC technology.
- A reduction in IGCC capital cost from a current cost of around $1300/kW to below $1000/kW.
- An improvement in overall IGCC plant efficiency from a current value of about 40 percent (HHV) to over 60 percent (HHV).

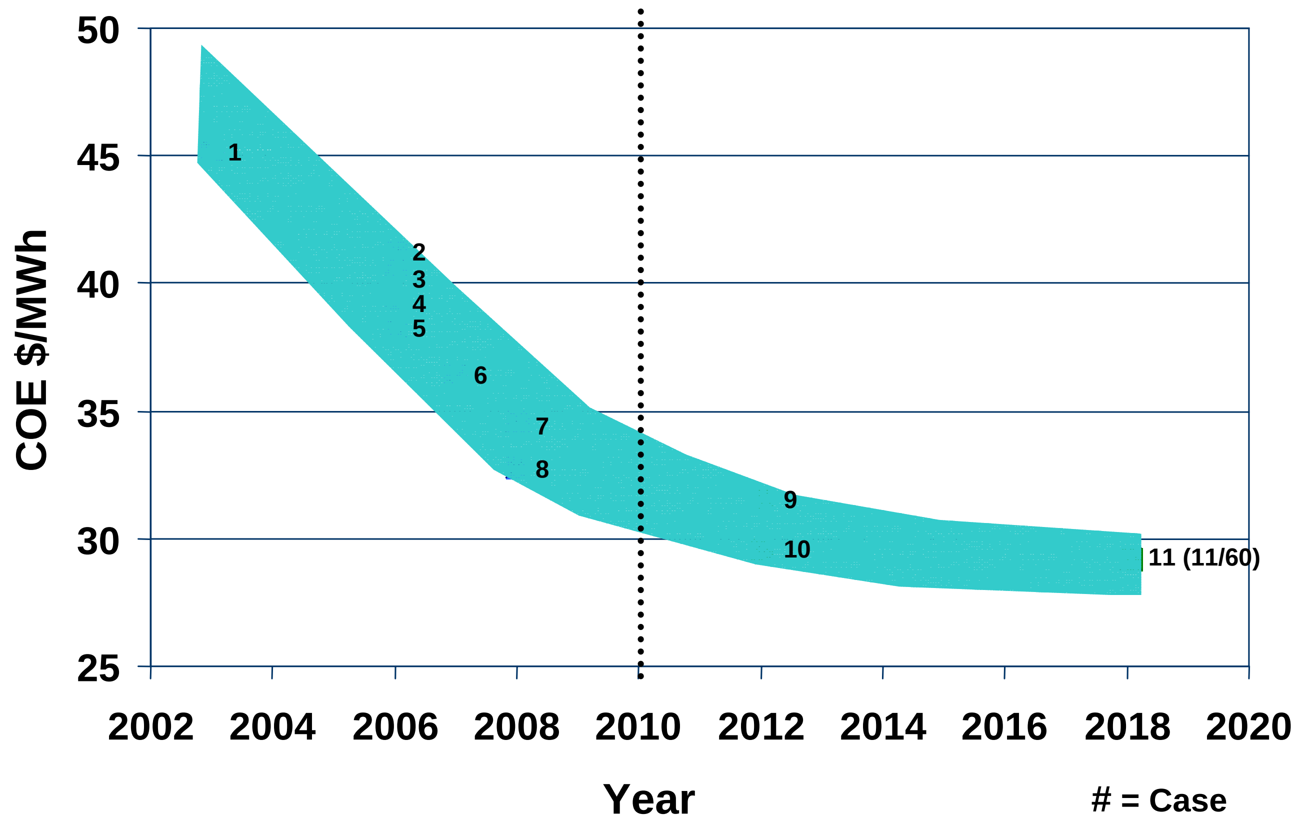


Figure 8. COE Timeline

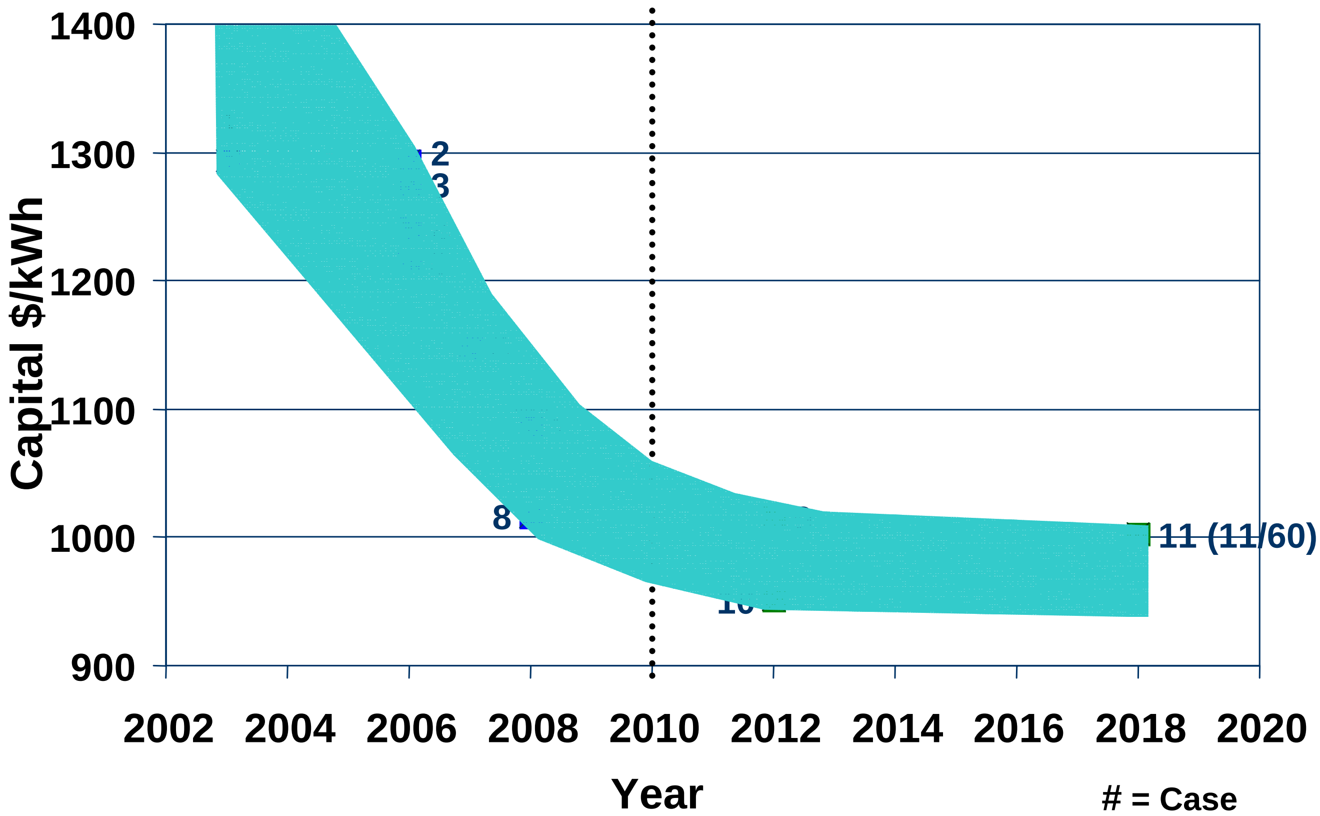


Figure 9. Capital Cost Timeline

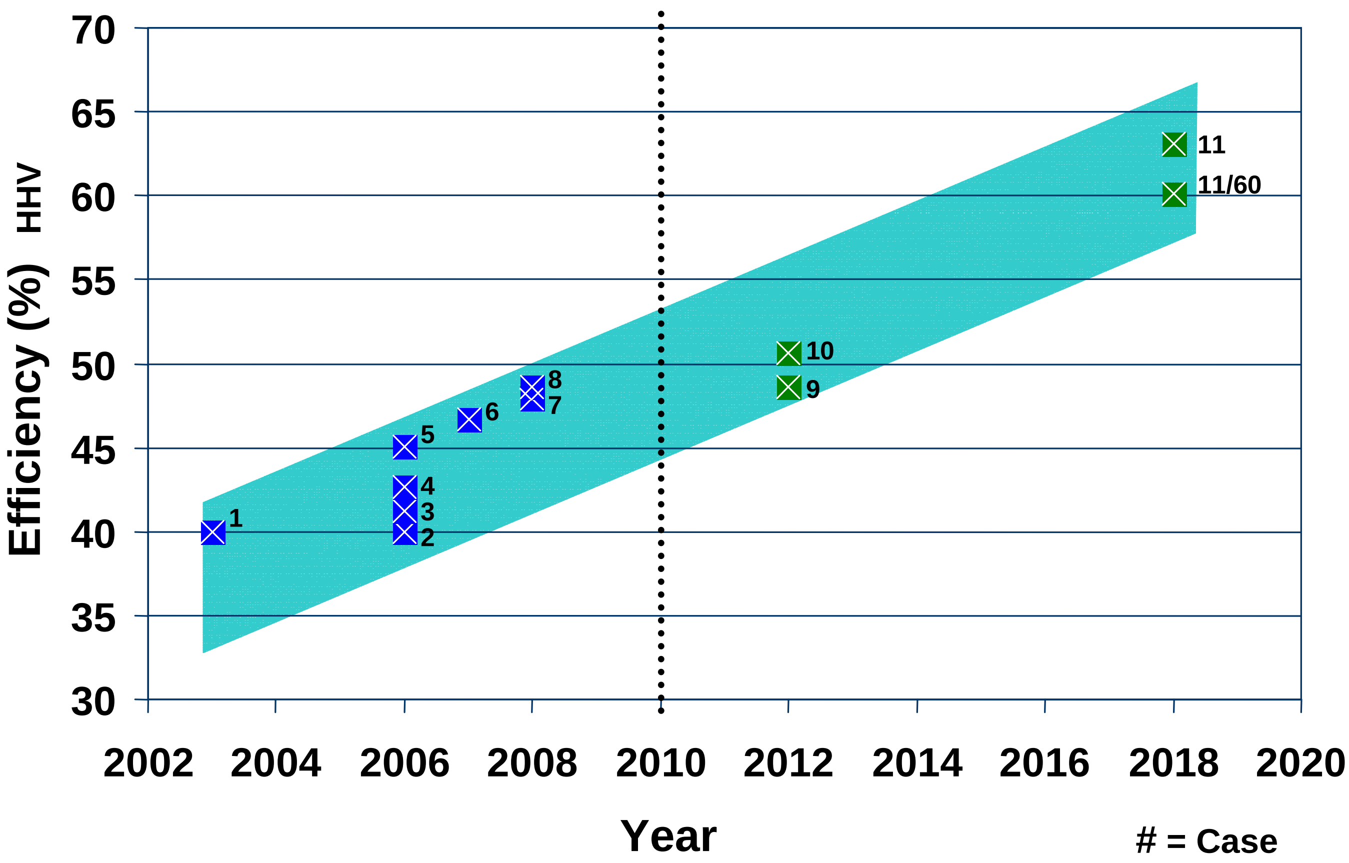


Figure 10. Efficiency Timeline

6.0 Analysis of Carbon Capture Cases

In all of the previous cases analyzed, there was no attempt to capture carbon dioxide in the IGCC configurations. Eventually, clean coal technologies may be required to capture and sequester carbon dioxide so that the ideal goal of zero emissions coal plants can be realized. Capturing carbon dioxide from IGCC configurations is relatively straight forward compared to carbon dioxide capture from post combustion pulverized coal plants. This is because the carbon dioxide is captured before combustion. This ease of carbon dioxide capture in IGCC plants is an important advantage of this technology compared to conventional pulverized coal combustion. Although carbon dioxide capture in IGCC is readily achievable, the subsequent sequestration or long term storage of the carbon dioxide presents other difficulties. This report only addresses capture of the carbon dioxide and assumes that adequate means of sequestration will be available when needed.

Three (3) carbon capture cases are analyzed in this report. They are:

- Case 12: A current slurry fed single-stage entrained flow gasification IGCC plant with raw gas shift, conventional gas cleaning, and 7F Frame gas turbines.
- Case 13: An IGCC configuration representing the year 2010 with advanced dry feed coal gasification, warm gas cleaning, 7 FB-frame gas turbines, and ITM oxygen in place of conventional cryogenic ASU.
- Case 14: An IGCC configuration representing the year 2020 with advanced gasification, warm gas cleaning, H frame gas turbine, ITM oxygen production, and SOFC topping cycle.

6.1 Case 12: Baseline Case: Current Slurry Feed Single Stage Gasification with 75 Percent Capacity and 95 Percent Carbon Utilization with Carbon Capture

Figure 11 shows a schematic of current IGCC plant technology with carbon dioxide capture. This plant configuration is very similar to the case 1 baseline plant except that this case incorporates raw water gas shift and bulk carbon dioxide removal and compression. It is assumed that a two stage Selexol plant is used to accomplish the removal of hydrogen sulfide and carbon dioxide. Like case 1, this configuration has two trains of single stage, slurry feed gasification with radiant heat recovery, two cryogenic air separation units, water scrub and raw water gas shift, two trains of hydrogen sulfide and carbon dioxide removal, one train of sulfur recovery using conventional Claus/SCOT technology, two trains of F-frame gas turbines, one HRSG, and one steam turbine system with high, intermediate, and condensing turbine sections.

Table 27 summarizes the process flows for selected streams for the case 12 plant configuration. This two train gasification plant processes 5,037 TPD of as-received

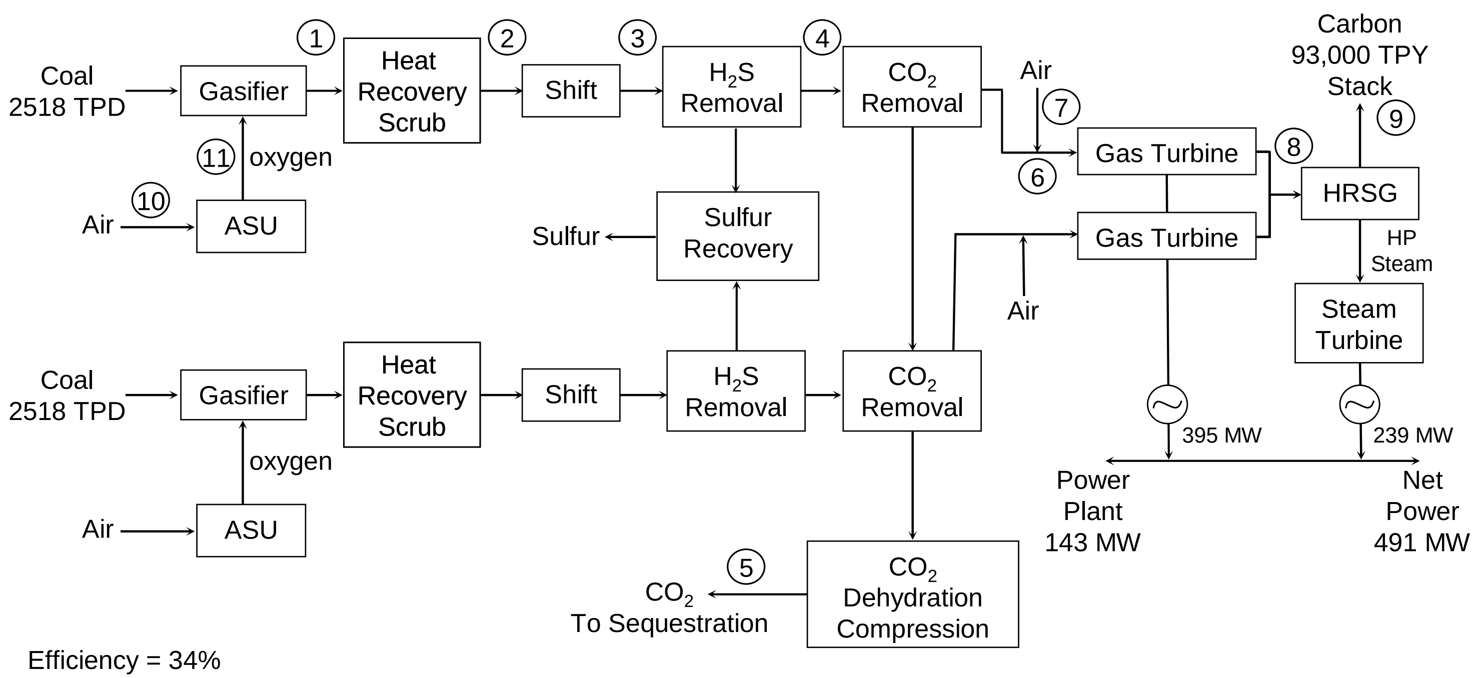


Figure 11. Case 12: Current IGCC Configuration with Carbon Dioxide Capture

Table 27: Case 12 Current IGCC Configuration with Carbon Dioxide Capture
Selected Flows, Moles/Hour
Flows Represent Totals for a Two Train System

	1	2	3	4	5	6	7	8	9	10	11
	Gasifier Output	Scrubber Exit	Shifted Gas	Clean Gas to CO2 Rem	CO2 to Seq'trtn	Fuel to Gas Turbine	Air to Gas Turbine	Feed to HRSG	HRSG EXIT	Air to ASU	Oxygen to Gasifier
CH4	1	1	1	1		1					
H2O	9,466	24,141	8,089	187				26,827	26,827		
H2	11,931	11,931	27,188	27,052		26,824					
CO	17,070	17,069	1,813	1,811		1,796					
CO2	4,118	4,118	19,375	19,375	18,832	538		2,334	2,334		
O2	0	0	0	0			32,763	28,276	28,276	10,302	10,302
N2	808	808	808	808		801	124,301	200,654	200,654	39,084	542
H2S	329	329	329	2	NIL	NIL		NIL	NIL		
NH3	NIL	NIL	NIL		NIL	NIL		NIL	NIL		
HCN	TRACE	TRACE	NIL		NIL	NIL		NIL	NIL		
Hg	TRACE	TRACE	TRACE		TRACE	TRACE		TRACE	TRACE		
COS	TRACE	TRACE	NIL		NIL	NIL		NIL	NIL		
HCl	TRACE	TRACE	NIL		NIL	NIL		NIL	NIL		
PM	TRACE	TRACE	NIL		NIL	NIL		NIL	NIL		
Total	43,722	58,397	57,601	49,234	18,832	29,959	157,064	258,092	2,334	49,386	10,844
Temperature, F	2,600	500	550	110	366	655	655	1062	260	686	567
Pressure, Psia	425	366	366	404	2,939	208	208	15	15	196	467

Power Summary, MW			Coal Input, T/Day AR		5,037				
							Carbon Balance		
Production:	MW							T/year	
Steam Turbine	239						In	879,938	as Coal
Gas Turbine	395		Gasifier Input, 1,000 #/hr						
Total	634		Coal	332			Out		
			Ash	41				786,989	Sequestered
Plant Use:			H2O (coal)	47				92,949	Exhaust
ASU	64		H2O (slurry)	176					
Oxygen Compressio	16		O2	330				89%	Sequestered
CO2 Compression	20								
MIscellaneous	43								
Total	143								
			Efficiency	34.2%					
Net Output	491								

coal to produce 491 MW of net power. Overall efficiency of this carbon capture plant is reduced to 34.2 percent and this can be compared to 40 percent (HHV basis) for the case 1-baseline plant with no carbon capture. This 15 percent lower efficiency is the result of the bulk carbon dioxide removal system and the carbon dioxide compression to 3000 psi. Although the loss of overall efficiency because of carbon dioxide capture is significant compared to a non-carbon capture case, it is far less of an efficiency penalty than carbon capture from pulverized coal (PC) power plants. According to Alstom, the loss of efficiency for a PC plant using Monoethanolamine scrubbing to remove carbon dioxide from flue gas is in the order of 43 percent.[6]

Carbon utilization in case 12 is 95 percent, and the capacity factor is assumed to be 75 percent, the same as in base case 1. This configuration captures about 90 percent of carbon in the feed coal. Total carbon input into the plant contained in the input coal is approximately 880,000 tons per year of carbon. After carbon capture, the quantity of carbon emitted from the plant per year is approximately 93,000 tons per year. Total power generated is 634 MW, 395 MW from the gas turbine, and 239 MW from the steam turbine. Parasitic power required is estimated to be 143 MW leaving a net power output of 491 MW.

The summary of the plant capital and operating and maintenance costs is shown in Table 28. The total installed plant construction cost is estimated to be $640 million. Addition of home office, process and project contingency brings the total plant cost to $813 MM. With addition of depreciable capital the total capital cost of the case 12 plant is estimated to be $841 MM. This results in a capital per unit power capacity of $1,656/kW if non-depreciable capital is excluded (net power output is 491 MW). Net annual operating and maintenance costs after by-product credit reduction are estimated to be $84.85 MM. Coal feedstock cost at $29.40 per ton ($1.26 per million Btu HHV basis) is $40.54 MM.

This economic data was used to calculate the RSP of the electric power from this plant. The economic assumptions used in the DCF are shown in Table 5. Using these financial assumptions, the RSP of electricity for this current carbon capture IGCC plant is calculated to be $56.99 per MWH.

6.2 Case 13: Dry Feed Gasification with 85 Percent Capacity, 98 Percent Carbon Utilization, FB-Gas Turbines, SCOHS Gas Cleaning, and ITM for Air Separation with Carbon Capture

Figure 12 shows a schematic of case 13. This plant concept is very similar to the case 8 IGCC plant in that the ITM system is used for air separation, SCOHS is used for sulfur removal, and 7 FB-frame gas turbines are used for power generation. However, in this case,

Table 28. Case 12: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	49
Gasification	144
Air Separation Unit (ITM)	75
Water-Gas Shift	23
Acid Gas Removal	23
Sulfur Recovery	20
CO_2 Removal/Compression	56
Gas Turbine	66
HRSG	33
Steam Turbine	35
Cooling/Feed Water Systems	36
Balance of Plant	81
Total Installed Cost	**640**
Home Office (8.4%)	54
Process Contingency (2%)	13
Project Contingency (15%)	106
Total Plant Cost	**813**
Non-depreciable Capital	28
Total Capital	**841**

Operating and Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	40.54
Cat/Chem Materials	9.61
Water	0.92
Operating and Maintenance Labor	11.23
Overhead/G&A	4.49
Administrative Labor	2.55
Local Taxes and Insurance	16.27
Solid Disposal	1.34
Gross Annual Operating Cost	86.95
By-product Credit	2.10
Net Annual Operating Cost	**84.85**

Net Power Output = 491 MW

RSP of Electricity (COE) = $56.99/MWH

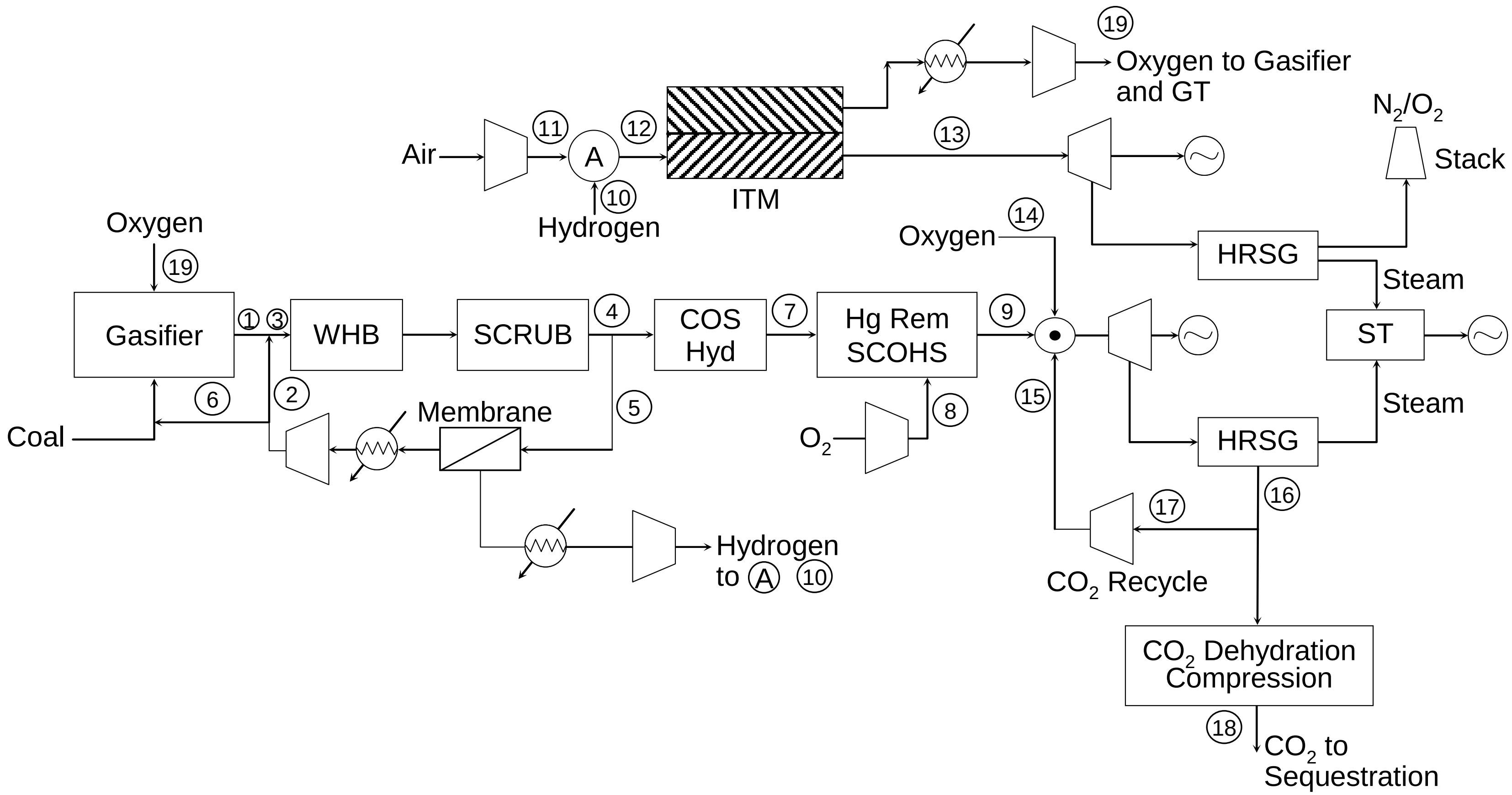


Figure 12. Case 13: Case 8 Concept Plant with Carbon Capture

all of the carbon dioxide produced is captured. If carbon sequestration technology is viable by year 2010, this configuration is expected to represent an IGCC plant in the year 2010 timeframe.

Like case 8, the coal is gasified in the presence of oxygen in a single stage dry feed gasifier to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, chloride, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 250ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to the SCOHS unit that was described earlier. Because this unit recovers the sulfur, the Claus/SCOT units are not required. The clean fuel gas stream is then sent to the oxygen fired FB gas turbine combustor. Carbon dioxide is recycled from the HRSG effluent to the gas turbine combustor to moderate the gas turbine flame temperature and to provide additional mass flow. The gas turbine exit gas consisting of carbon dioxide and water vapor is sent to a HRSG for steam generation and the HP steam is used in the steam turbine for power generation. The HRSG effluent gas is all carbon dioxide and water vapor because the combustor was oxygen fired. This is sent to carbon dioxide dehydration and compression so that a pure stream of compressed carbon dioxide can be ready for sequestration.

As shown in Figure 12, the ITM air is compressed to 16 atmospheres and then this compressed air is heated in a hydrogen fired combustor to heat this air to the ITM reactor temperature. Hydrogen is used so that no carbon dioxide is produced in this combustor. The hydrogen is produced by using a hot membrane separator in the gasifier bleed gas stream. The hot membrane separator maintains system pressure of the recycle gas and is also assumed to shift the gas to produce more hydrogen. The recovered hydrogen is cooled and compressed before being sent to the ITM combustor. The oxygen depleted air exiting the ITM reactor at 1,650ºF is sent to an expander for power generation and the expander exit gas is sent to a HRSG for steam production. This steam is used in the steam turbine to generate power. The effluent from the ITM HRSG contains only nitrogen and oxygen and this is vented through the stack. The pure oxygen stream exiting the ITM reactor is sent to heat recovery to produce steam and then compressed and sent to coal gasification.

Table 29 summarizes the process flows for selected streams for the case 13 plant configuration. This two train gasification plant processes 4,394 TPD of as-received coal to produce 523 MW of net power. Overall efficiency of this carbon capture plant is 41.7 percent and this can be compared to 48.3 percent (HHV basis) for the case 8 plant with no carbon capture. This lower efficiency is the result of capturing and preparing the carbon dioxide for sequestration.

Table 29: Case 13: Case 8 with Carbon Capture

Selected Flows, Moles/Hour

	1 Gasifier Output	2 Recycle Gas	3 Mixed Gas	4 Scrubber Exit	5 Bleed Gas	6 Coal Feed Gas (Dry)	7 SCOHS Input	8 SCOHS Oxygen	9 SCOHS Exit
CH4	15	5	20	14	6	1	14		14
H2O	888	3	891	2,010	270	0	2,010		2,283
H2	9,282	442	9,724	6,780	2,944	60	6,780		6,780
CO	19,426	591	20,017	13,957	6,060	81	13,957		13,957
CO2	621	6,687	7,307	5,095	2,212	914	5,095		5,095
O2	0	0	0	0	0	0	0	545	412
N2	273	99	372	259	112	14	259		259
H2S	287	104	391	273	118	14	273		0
NH3	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL
HCN	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
Hg	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
COS	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
HCl	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL
PM	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL
Total	30,791	7,931	38,722	28,388	11,723	1,084	28,388	545	28,799
Temperature, F	2,500	128	1900	244	244	500	244	839	376
Pressure, Psia	425	425	425	382	382	537	382	441	330

	10 ITM Heater Fuel	11 Air to ITM	12 Heated ITM Input	13 Depleted ITM Air	14 Oxygen Gas Turb	15 Gas Turb Fuel	16 HRSG Exhaust	17 CO2 Recycle	18 CO2 Sequestered	19 Oxygen to Gasifier
CH4	0		0	0		14	0			
H2O	0		7,830	7,830		2,282	9,090			
H2	7830		0	0		6,780	0			
CO	0		0	0		13,955	0			
CO2	0		0	0		5,095	113,782	94,718	19,064	
O2	0	25,264	21,349	6,311	10,500	412	516	430	86	7,908
N2	0	95,852	95,852	95,852		259	259	216	43	
H2S	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
NH3	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
HCN	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
Hg	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
COS	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
HCl	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
PM	NIL		NIL	NIL		NIL	NIL	NIL	NIL	
Total	7,830	121,116	125,031	109,993	10,500	28,796	123,647	95,363	19,194	7,908
Temperature, F	537	839	1,652	1,652	839	376	260	771	80	306
Pressure, Psia	278	265	251	251	265	330	15	265	2000	467

Power Summary, MW				Coal Input, T/Day AR		4,394
Production:		MW				
Steam Turbine		274				
Air Cycle Turbine (net)		34		Gasifier Inpu	1000#/Hr	
Expander		422		Coal	290	
Total			730	Ash	36	
				H2O	41	
Plant Use:				O2	253	
ITM O2 Compression		29				
CO2 Recycle Compression		129				
CO2 Sequestration Compression		34				
Miscellaneous		15		Efficiency	41.7%	
Total		207				
	Net Output	523				

Carbon utilization in this case 13 is 98 percent and the capacity factor is assumed to be 85 percent. Total power generated is 730 MW, 422 MW from the gas turbine expander, 274 MW from the steam turbine, and 34 MW net from the air cycle turbine. Parasitic power required is estimated to be 207 MW leaving a net power output of 523 MW.

The summary of the plant capital and operating and maintenance costs is shown in Table 30. The total installed plant construction cost is estimated to be \$567 million. Addition of home office, process and project contingency brings the total plant cost to \$720 MM. With addition of depreciable capital the total capital cost of the case 13 plant is estimated to be \$744 MM. This results in a capital per unit power capacity of \$1,377 per kilowatt if non-depreciable capital is excluded. Net annual operating and maintenance costs after by-product credit reduction are estimated to be \$79.97 MM. Coal feedstock cost at \$29.40 per ton (\$1.26 per million Btu HHV basis) is \$40.08 MM.

This economic data was used to calculate the RSP of the electric power from this plant. The economic assumptions used in the DCF analysis are shown in Table 5. Using these financial assumptions the RSP of electricity for this carbon capture IGCC plant is calculated to be \$43.04 per MWH.

6.3 Case 14: Dry Feed Gasification with 90 Percent Capacity, 98 Percent Carbon Utilization, F-Type Gas Turbine, SCOHS Gas Cleaning, ITM for Air Separation, and SOFC with Carbon Capture

Case 14 is similar in concept to case 11 described above. SOFC stacks are used as the topping cycle before the gas turbine in an IGCC configuration. The main difference between case 14 and case 11 is that all of the carbon dioxide produced in the plant is captured. This plant configuration is projected to be representative of an advanced IGCC plant by year 2020 assuming that carbon dioxide sequestration is viable by then.

Figure 13 shows the schematic for this integrated SOFC/IGCC configuration with carbon dioxide capture. The clean coal-derived synthesis gas is produced in the same way as it is produced in case 11. The coal is gasified in the presence of oxygen in a single stage dry feed gasifier to produce the raw fuel gas. The raw fuel gas is cooled below the ash fusion temperature by recycling cool product gas, before passing into the WHB where high pressure steam is produced. The raw gas is then sent to a water scrub to remove ammonia, cyanide and residual particles and then to a COS hydrolysis unit. The gas exiting the COS hydrolysis unit is cooled to about 275ºF where it is assumed that mercury can be removed in this temperature range. The gas is then sent to a SCOHS unit for removal of hydrogen sulfide. Because this unit recovers the sulfur, the Claus/SCOT units are not required. The clean fuel gas is then sent to the anode of the SOFC stacks.

Table 30. Case 13: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary	$MM (2002)
Coal Handling/Feeding	44
Gasification	126
Air Separation Unit (ITM)	79
Acid Gas Removal (incl. COS Hyd)	22
Hydrogen Recovery	16
CO_2 Removal/Compression	38
Gas Turbine	54
HRSG	37
Steam Turbine	40
Cooling/Feed Water Systems	35
Balance of Plant	76
Total Installed Cost	**567**
Home Office (8.4%)	48
Process Contingency (2%)	11
Project Contingency (15%)	94
Total Plant Cost	**720**
Non-depreciable Capital	24
Total Capital	**744**

Operating and Maintenance Cost Summary	$MM (2002)
Coal ($29.40/Ton AR)	40.08
Cat/Chem Materials/Water	10.72
Operating and Maintenance Labor	9.94
Overhead/G&A	3.97
Administrative Labor	2.25
Local Taxes and Insurance	14.39
Solid Disposal	1.32
Gross Annual Operating Cost	82.67
By-product Credit	2.70
Net Annual Operating Cost	**79.97**

Net Power Output = 523 MW

RSP of Electricity (COE) = $43.04/MWH

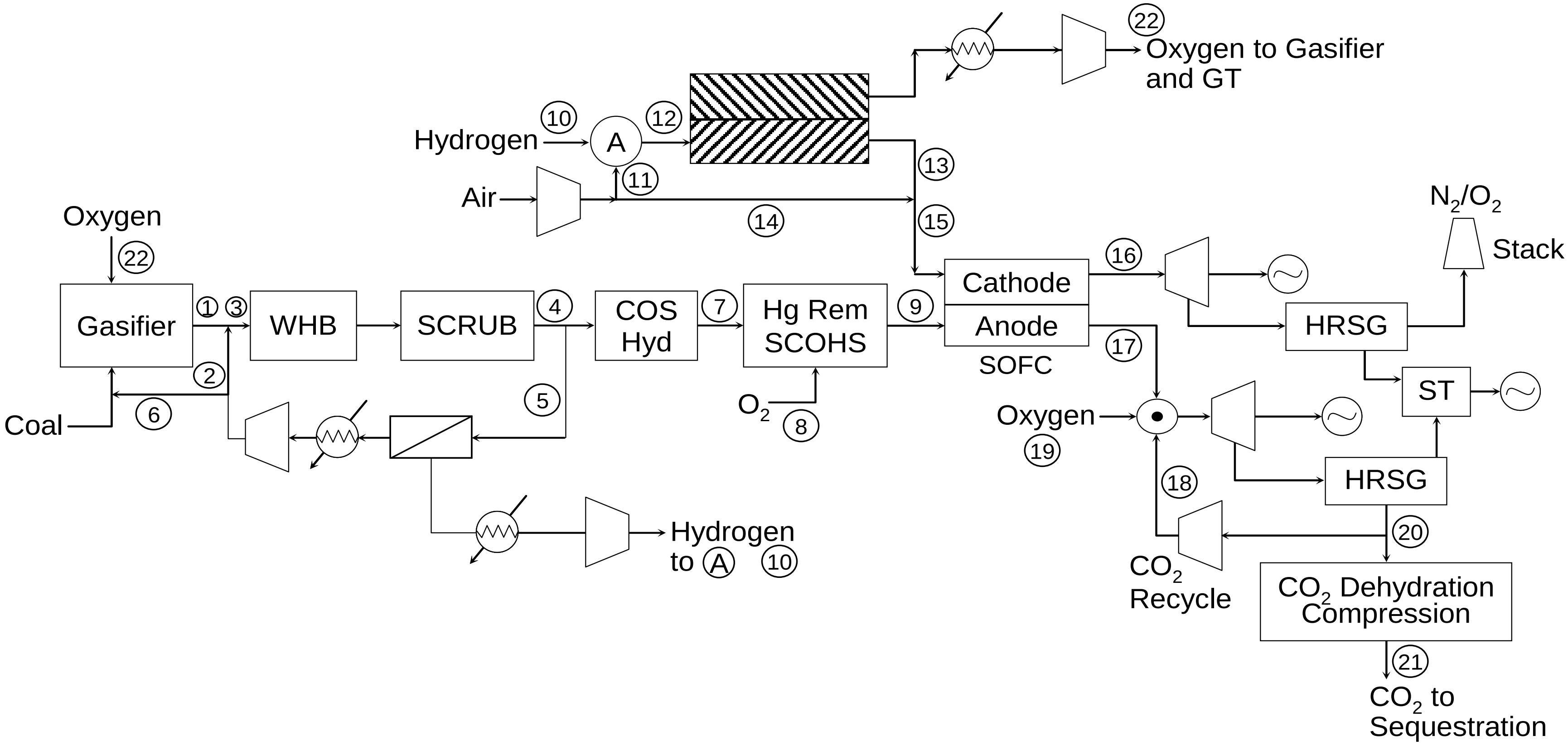


Figure 13. Case 14: Integration of ITM-O_2 with SOFC (Carbon Capture)

The SOFC stacks generate 311 MW of electric power. It is assumed that 85 percent of the clean synthesis gas is converted into electrical energy in the fuel cell at an electrical efficiency of 60 percent. The fuel cell is assumed to operate at a temperature of 2000°F and system pressure of about 20 atmospheres. Referring to Figure 13, the exit gas from the SOFC anode is at 2000°F and system pressure, and this is sent to an oxygen fired combustor with carbon dioxide recycle and then expanded in a gas turbine to generate electric power. The gas turbine expander exit gas is sent to a HRSG for steam generation, and the HP steam is used in the steam turbine for power generation. The HRSG effluent gas is all carbon dioxide and water vapor because the combustor was oxygen fired. This is sent to carbon dioxide dehydration and compression so that a pure stream of compressed carbon dioxide can be ready for sequestration.

The air input to the ITM is compressed and heated in the same manner as the previous case by using a hydrogen-fired combustor. The oxygen depleted air from the ITM unit is sent to the SOFC cathode. The oxygen from the ITM unit is cooled and compressed then sent to coal gasification. The hot gas exiting the SOFC cathode is sent to a turbine expander for power generation and the expander effluent gas enters the HRSG and the HP steam generated is sent to the steam turbine generator. The effluent gas exiting the HRSG contains only nitrogen and oxygen and is vented into the stack. The capacity factor is 90 percent and the carbon utilization is 98 percent.

Table 31 summarizes the process flows for selected streams for the case 14 SOFC/IGCC plant configuration. This single train gasification plant processes 3,135 TPD of as-received coal to produce 533 MW of net power. Overall efficiency is 59.7 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 90 percent. Total power generated is 757 MW, 142 MW from the anode turbine expander, 311 MW from the SOFC, 185 MW from the cathode expander, and 120 MW from the steam turbine. Parasitic power required is estimated to be 224 MW.

Table 32 is a summary of the plant capital and operating and maintenance costs for case 14. In case 14, the total installed plant construction cost is estimated to be $522 MM and the total capital cost of the case 14 plant is $662 MM. Excluding non-depreciable capital, this is a capital investment cost of $1,242/kW. It is assumed that the SOFC capital is $400/kW. Net plant power output is 533 MW. Net annual operating and maintenance costs after by-product credit reduction are estimated to be $68.5 MM. At $29.40 per ton ($1.26 per million Btu HHV basis), the coal feed cost is $30.28 MM. The RSP of the electric power from this plant is calculated to be $35.42 per MWH.

Table 31: Case 14: Integration of ITM-O2 With SOFC (Carbon Capture)

Selected Flows, Moles/Hour

	1	2	3	4	5	6	7	8	9	10	11
	Gasifier Output	Recycle Gas	Mixed Gas	Scrubber Exit	Bleed Gas	Coal Feed Gas (Dry)	SCOHS Input	SCOHS Oxygen	SCOHS Exit	ITM Heater Fuel	Air to ITM
CH4	11	4	15	15	4	1	11		11	0	
H2O	646	9	655	2,102	576	1	1,526		1,526	0	
H2	6,900	2,085	8,986	8,986	2,462	335	6,524		6,524	3311	
CO	13,868	599	14,467	14,467	3,964	96	10,503		10,503	0	
CO2	434	3,821	4,255	4,255	1,166	614	3,089		3,089	0	
O2	0	0	0	0	0	0	0	389	294	0	9,962
N2	195	60	255	255	70	10	185		185	0	44,077
H2S	205	63	268	268	73	10	195		0		
NH3	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL		
HCN	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL		
Hg	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL		
COS	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL		
HCl	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE	TRACE		NIL		
PM	TRACE	TRACE	TRACE	NIL	NIL	NIL	NIL		NIL		
										3,311	54,040
Total	22,260	6,641	28,901	30,347	8,315	0	22,032	389	22,132	571	915
Temperature, F	2,500	170	1900	243	243	500	243	915	368	340	323
Pressure, Psia	425	456	425	382	382	571	382	441	330		

	12	13	14	15	16	17	18	19	20	21	22
	Heated ITM Input	Depleted ITM Air	Cathode Air	Combined Cath. Flow	Cathode Exit	Anode Exit	Recy CO2	Oxygen to Turbine	HRSG Exit	Sequestered CO2	Oxygen to Gasifier
CH4	0	0		0	0	0					
H2O	3,311	3,311		3,311	3,311	7,779			8,243		
H2	0	0		0	0	465					
CO	0	0		0	0	1,549					
CO2	0	0		0	0	12,042	19,930		33,521	13,591	
O2	9,962	2,411	5,335	7,746	533		293	1,500	493	200	5,662
N2	44,077	44,077	20,240	64,317	64,317	185	110		185	75	0
H2S						NIL	NIL		NIL	NIL	
NH3						NIL	NIL		NIL	NIL	
HCN						NIL	NIL		NIL	NIL	
Hg						NIL	NIL		NIL	NIL	
COS						NIL	NIL		NIL	NIL	
HCl						NIL	NIL		NIL	NIL	
PM						NIL	NIL		NIL	NIL	
Total	57,350	49,799	25,575	75,374	68,161	22,019	20,334	1,500	42,443	13,866	5,662
Temperature, F	1,652	2,000	915	1409	2,000	2000	792	306	260	80	306
Pressure, Psia	323	307	323	307	292	314	330	467	16	2000	467

Power Summary, MW		Coal Input, T/Day AR		3,135				
Production:	MW							
Steam Turbine	119.7					Carbon Balance		
Fuel Cell	311.4						T/year	
Cathode Turbine	184.5	Gasifier Inpu	1000#/Hr			In	643,481	as Coal
Anode Turbine	141.5	Coal	207					
Total	757.1	Ash	25			Out		
		H2O	29				643,481	Sequestered
Plant Use:		O2	181					
Oxygen Compression	11.5							
Air Compressor	146.4						99.99%	Sequestered
CO2 Recycle Comprsn	30.0							
CO2 Seqstration Comp	24.2							
MIscellaneous	11.8							
Total	223.9	Efficiency	59.7%					
Net Output	533.2							

Table 32. Case 14: Capital and Operating and Maintenance Cost Summary

Capital Cost Summary

	$MM (2002)
Coal Handling/Feeding	32
Gasification	95
Acid Gas Removal (incl. COS Hyd)	20
Hydrogen Recovery	7
CO_2 Removal/Compression	27
Fuel Cell	125
Gas Turbine	54
HRSG	20
Steam Turbine	20
Cooling/Feed Water Systems	22
Balance of Plant	64
Total Installed Cost	**522**
Home Office (8.4%)	44
Process Contingency (2%)	10
Project Contingency (15%)	86
Total Plant Cost	**662**
Non-depreciable Capital	23
Total Capital	**644**

Operating & Maintenance Cost Summary

	$MM (2002)
Coal ($29.40/Ton AR)	30.28
Cat/Chem Materials/Water	9.45
Operating and Maintenance Labor	9.14
Overhead/G&A	3.70
Administrative Labor	2.10
Local Taxes and Insurance	13.25
Solid Disposal	1.00
Gross Annual Operating Cost	68.92
By-product Credit	1.00
Net Annual Operating Cost	**67.92**

Net Power Output = 533 MW

RSP of Electricity (COE) = $35.42/MWH

7.0 Summary Analysis of Carbon Capture Cases

Table 33 summarizes the results of the conceptual IGCC plant analyses for the three (3) carbon dioxide capture cases.

In case 12, the plant configuration is very similar to the case 1 baseline plant except that this case incorporates raw water gas shift and bulk carbon dioxide removal and compression. Like case 1, this configuration has two trains of single-state slurry feed gasification with radiant heat recovery, two cryogenic air separation units, water scrub and raw water gas shift, two trains of hydrogen sulfide and carbon dioxide removal, one train of sulfur recovery using conventional Claus/SCOT technology, two trains of F-frame gas turbines, one HRSG, and one steam turbine system with high, intermediate, and condensing turbine sections.

This two train gasification plant processes 5,037 TPD of as-received coal to produce 491 MW of net power at an efficiency of 34.2 percent. This can be compared to 40 percent (HHV basis) for the case 1 baseline plant with no carbon capture: a 15 percent lower efficiency. This efficiency loss is small compared to about 40 percent efficiency loss from PC power plants using amine scrubbers to remove carbon dioxide. The case 12 configuration captures about 90 percent of the carbon in the feed coal. Total power generated is 634 MW, 395 MW from the gas turbine and 239 MW from the steam turbine. Parasitic power required is estimated to be 143 MW leaving a net power output of 491 MW. The total plant cost to $813 MM. This results in a capital per unit power capacity of $1,656/kW if non-depreciable capital is excluded. The RSP of electricity for this current carbon capture IGCC plant is calculated to be $56.99 per MWH. This can be compared to a COE of $45.20 per MWH for case 1, a 26 percent increase.

The case 13 plant concept is very similar to the case 8 IGCC plant in that the coal is gasified in a dry feed gasifier, an ITM system is used for air separation, SCOHS is used for sulfur removal, and 7-FB frame gas turbines are used for power generation. However, in this case, all of the carbon dioxide produced is captured. This two train gasification plant processes 4,394 TPD of as-received coal to produce 523 MW of net power. Overall efficiency of this carbon capture plant is 41.7 percent and this can be compared to 48.3 percent (HHV basis) for the case 8 plant with no carbon capture. This lower efficiency is the result of the oxygen fired gas turbine and readying the carbon dioxide for sequestration. Carbon utilization in this case 13 is 98 percent and the capacity factor is assumed to be 85 percent. This carbon capture plant is a zero emissions facility with respect to carbon dioxide. The configuration with an oxygen fired gas turbine combustor and a hydrogen fired combustor for heating the ITM air allows for the capture of all of the carbon dioxide produced in the plant.

Table 33. Summary: Bituminous Coal to Power (Carbon Capture)

Case	12	13	14
COE ($/MWH)	56.99	43.04	35.42
Capital ($MM)	813	720	662
Efficiency (%)	34.2	41.7	59.7
Output (MW)	491	523	533
Capital ($/kW)	1,656	1,377	1,242
Coal Feed (TPD)	5,037	4,394	3,135

Total power generated in case 13 is 730 MW and parasitic power required is estimated to be 207 MW leaving a net power output of 523 MW. The total plant capital cost is $720 MM. With addition of depreciable capital the total capital cost of the case 13 plant is estimated to be $744 MM. This results in a capital per unit power capacity of $1,377/kW if non-depreciable capital is excluded. The RSP of electricity for this carbon capture IGCC plant is calculated to be $43.04 per MWH. This can be compared to case 8 where the COE was estimated to be $32.7 per MWH, a 32 percent increase.

Case 14 is similar in concept to case 11 described above. SOFC stacks are used as the topping cycle before the gas turbine in an IGCC configuration. The main difference between case 14 and case 11 is that all of the carbon dioxide produced in the plant is captured. The SOFC stacks generate 311 MW of electric power. The capacity factor is 90 percent and the carbon utilization is 98 percent. Net power output is 533 MW, and the overall efficiency is 59.7 percent. This can be compared to the efficiency of the case 11 plant at 65 percent. This plant is also a zero emissions plant with respect to carbon dioxide. In case 14, the total installed plant construction cost is estimated to be $522 MM, and the capital cost, without depreciable capital, is $662 MM. Excluding non-depreciable capital, this is a capital investment cost of $1,242/kW. The RSP of the electric power from this plant is calculated to be $35.42 per MWH. This can be compared to case 11 where the COE was estimated to be $29.20 per MWH, a 21 percent increase.

This analysis shows that there are potentially significant improvements that could result from continuing RD&D in advanced IGCC systems with carbon capture. These are:

- Advanced technology has the potential to reduce COE by about 38 percent compared to current IGCC carbon capture technology.
- A reduction in IGCC capital cost from a current cost of around $1660/kW to $1240/kW for carbon capture IGCC plants.
- An improvement in overall IGCC plant efficiency from a current value of about 34 percent (HHV) to almost 60 percent (HHV) for carbon capture IGCC plants.

8.0 CONCLUSIONS AND R&D ISSUES

This report has estimated capital cost reductions and improvements in overall efficiency for fifteen (15) IGCC cases. The potential reductions in the RSP of the electric power produced from these IGCC plants over a time span of about fifteen (15) years is the direct result of the successful deployment of advanced technologies. ***It must be cautioned that these advances in IGCC technology over time will only come about if continued RD&D proves to be successful and leads to the commercialization, deployment, and integration of these technologies into the overall IGCC system.*** These advanced technologies include advances in gasification, gas turbines, synthesis gas cleaning, air separation, hydrogen membrane separation, and development of stationary fuel cells. Thus all aspects of the IGCC system are assumed to undergo technological advances in this time frame. These improvements translate into significant reductions in the RSP or COE of the electricity generated by these advanced IGCC facilities for both non-carbon capture and carbon capture plants.

Referring to Table 26, for the non carbon captured IGCC cases, the COE is estimated to be reduced from $45.20/MWH in the current or base case to $29.20/MWH in the very advanced SOFC case; a reduction of 35 percent. This reduction is possible because of the incorporation of several improvements into the IGCC system. An important contributor is the increase in capacity factor and carbon utilization in the coal gasifier. This implies that the RAM of the gasifier can be improved so that single train units can attain on-stream times of 85 to 90 percent. High availability has been demonstrated by Eastman at their coal gasification facility in Kingsport Tennessee and they have formed the Eastman Gasification Services Company to provide support to the gasification community. Improvements in RAM can best be attained from experience in running large scale commercial units. However, R&D in materials, particularly in burners and refractories, can impact RAM performance. Improving capacity from 75 to 85 percent decreased the COE by nearly 9 percent. Increasing the carbon utilization reduced COE by 1.5 percent.

Improvements in gasifier design can also impact efficiency and cost. Substitution of slurry feed single stage gasification for single-stage dry feed gasification increases cold gas efficiency and hence overall efficiency. Ideally, a two-stage dry feed system should show the greatest efficiency. Dry feed systems like Shell and possibly the Transport gasifier have the potential to improve the IGCC system. Replacing the slurry feed single stage gasifier with a two-stage slurry system reduced the COE by almost 3 percent. Replacing slurry feed systems with a dry feed gasifier decreased COE by about 3 percent.

Gas turbine performance is a critical parameter in the overall IGCC system. Replacing the F-frame machine with an advanced FB-turbine working on synthesis gas is estimated to reduce COE by almost 5 percent due to the improved overall plant efficiency. Some of this decrease in COE was due to economy of scale because the FB-frame turbine plant was larger. Incorporation of the advanced H-frame machine was estimated to further reduce COE by 5 percent and increase the IGCC overall plant efficiency by over 4 percent.

For clean synthesis gas production, warm gas cleaning processes offer the potential to improve efficiency by simplifying the clean up train, maintaining moisture content of the gas, and minimizing synthesis gas heating and cooling cycles. The SCOHS process used in this study is estimated to have a very positive impact on the IGCC system by reducing energy inputs and by eliminating sulfur recovery equipment. Compared to conventional amine based cleaning, the COE is reduced by 5 percent. However, it is cautioned that SCOHS is in the very early stages of development and the assumed performance of this unit has not been obtained in practice.

If the ITM system is used to replace the conventional cryogenic ASU, the impact on COE is estimated to be about 5 percent. This ITM concept is still in the early stages of development; and there are many hurdles that must be overcome before large scale membrane units are commercialized. This analysis assumes that a successful ITM system could be developed for 66 percent of the cost of a cryogenic unit of the same capacity. It was also assumed that successful integration of the ITM unit with the gas turbine could be achieved.

Integration of SOFCs as a topping cycle for the gas turbine was estimated to reduce COE by only about 1 percent. This was in spite of the fact that the assumed capital cost for the SOFC was $400/kW installed. However, the SOFC had a dramatic effect on the overall efficiency of the IGCC plant increasing it from about 50 to over 60 percent. Achieving an overall IGCC plant efficiency of 60 percent from coal (the DOE target for the year 2020) can ***only*** be realized with successful hybrid fuel cell systems.

Referring to Table 33 for the carbon capture IGCC plants, the COE is estimated to decrease from $57/MWH for the current baseline configuration with carbon capture to $35.42/MWH for an advanced facility incorporating dry feed gasifiers, warm gas cleaning, ITM, and SOFC as topping cycle. This is a decrease of about 38 percent. With the SOFC integration, it appears possible to achieve almost 60 percent overall plant efficiency of coal to power even with carbon capture. This is contingent upon the successful optimal integration of the ITM unit, the SOFC, and the oxygen fired gas turbine as described in the report.

The main RD&D issues emanating from this analysis are as follows:

- Warm gas cleaning processes are important to the overall IGCC system because at higher temperatures, the gas maintains moisture content and some sensible heat. The SCOHS process is particularly attractive because it promises to perform the dual function of removing hydrogen sulfide and recovering sulfur in one simple reactor at temperatures around 300ºF. Raw coal derived synthesis gas contains many constituents that must be removed before the gas turbine. These include particulates, chlorides, cyanide, ammonia, maybe carbonyls, hydrogen sulfide, carbonyl sulfide, and trace metals including mercury. Water scrubbing of the gas generally removes chloride, ammonia, and cyanide but water scrubbing reduces the temperature of the synthesis gas to around 350-400ºF. Warm cleaning systems that remove and recover hydrogen sulfide and that operate around 300-400ºF would then be compatible with water scrubbing of the gas and hydrolysis of carbonyl sulfide that is favored around 375ºF. Failing the development of an ideal system that would operate at gasifier outlet temperatures around 2000ºF, remove all of the impurities and provide a clean gas for the turbines, the SCOHS process is a worthy candidate for R&D. There is, however, a potential problem concerning the effective removal of mercury at warm gas cleaning temperatures. This analysis assumed that mercury could be removed in the temperature range 300-400ºF. However, if removal requires low synthesis gas temperatures as practiced at the Eastman Texaco plant, then warm gas cleaning would have to be followed by gas cooling and mercury removal at low temperature in activated carbon beds. SCOHS would, however, retain much of its advantage by eliminating the Claus and SCOT units for sulfur recovery.

- It was evident from this analysis that advanced gas turbines contribute significantly to improved overall efficiency and lower costs of electricity. R&D on the successful development of the FB and H-frame machines on synthesis gas and integration of the gas turbines with the air separation unit and the overall IGCC system, ***must*** be an important priority in any IGCC RD&D program plan.
- Air separation using the ITM system did contribute to improvements in the IGCC system if the performance estimates used in this analysis can be demonstrated at commercial scale. Because of the high temperature of operation of ITM (circa 1600ºF), heat management and optimal integration into the IGCC system are critical issues. In many of the analyses in this report the ITM system is integrated with the gas turbine. It is assumed that the gas turbine compressor is used to compress the air to the ITM, as well as, the air to the gas turbine combustor. A synthesis gas burner is used to preheat the ITM feed air, and hot ITM depleted air effluent is sent to the gas turbine combustor. This integration is conceptual and none of this integration has been demonstrated in practice. R&D is needed to demonstrate and define the optimal integrated configuration for these units. When the ITM is integrated with a SOFC, it is assumed in this report that the hot ITM depleted air effluent can be sent directly to the SOFC cathode. R&D is needed to optimize integration of fuel cells with the ITM system. In the configurations using ITM oxygen with complete carbon dioxide sequestration, hydrogen fired combustors were conceptualized to preheat the ITM air. The hydrogen was assumed to be obtained from gasifier recycle gas using advanced hot membrane separation that incorporated water gas shift activity. These membrane systems are in an early stage of development and much RD&D will be needed before they can be utilized in commercial applications.

- The incorporation of a SOFC into the IGCC system had a dramatic effect on overall system efficiency. In this report it was assumed that large scale stationary SOFC stacks could be commercialized that generated over 300 MW of power. Fuel cell development is currently at an early stage and fuel cell stacks are currently less than a MW. Considerable RD&D will be needed to prove these units at large scale. In addition, it was assumed that these SOFCs could operate at pressures compatible with gas turbine inlet pressures of around 16 to 20 bar. Higher pressure operation of SOFC must be proven. Also the system integration of the SOFC with the ITM unit and the gas turbine needs to be demonstrated.
- The importance of IGCC capacity factor was quantified in this report. Reliable coal gasification operation with high availability and maintainability is a critically important issue that can contribute to lowering the COE from IGCC plants. ***Industry will not embrace IGCC as a technology until it can prove to be as reliable as conventional pulverized coal technologies.*** It is capital intensive to have spare gasifiers at the IGCC plant, and O&M costs are increased if they have to be kept on standby mode. On-stream capacity for single gasifier units should be as high as possible, around 85 percent (or 310 days per year on stream). IGCC plants when built will have the lowest dispatch power cost of the generating system; and therefore, will generate power at base load to the fullest extent possible. RD&D to improve gasifier RAM should be an essential part of an IGCC deployment program. ***The ultimate goal would be to produce standard, bankable, reliable IGCC designs just as today there are reliable standard PC plant designs.***

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List of Acronyms

AGR	Acid Gas Removal
ASU	Air Separation Unit
COE	Cost of Electricity
COS	Carbonyl Sulfide
DCF	Discounted Cash Flow
DOE	Department of Energy
F	Turbine Type
FB	Turbine Type
GT	Gas Turbine
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
ITM	Ionic Transport Membrane
kW	kilowatt
MW	megawatt
MWH	megawatt hour
NOx	Nitrogen Oxides
PC	Pulverized Coal
PM	Particulate Matter
R&D	Research and Development
RAM	Reliability, Availability and Maintainability
RD&D	Research, Development and Demonstration
RSP	Required Selling Price
SCOHS	Selective Catalytic Oxidation of Hydrogen Sulfide
SCOT	Shell Class Offgas Treatment
SOFC	Solid Oxide Fuel Cells
SOx	Sulfur Oxides

TPD	tons per day
WGCU	Warm Gas Cleanup
WHB	Waste Heat Boiler