Process Engineering Division

Destec Gasifier IGCC Base Cases

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PREFACE

This report presents the results of an analysis of two Destec Gasifier IGCC Base Cases. The analyses were performed by W. Shelton and J. Lyons of EG&G.

EXECUTIVE SUMMARY

DESTEC GASIFIER IGCC BASE CASES

EXECUTIVE SUMMARY

ASPEN PLUS (version 10.1) Simulation Models and the Cost of Electricity (COE) have been developed for two IGCC cases based on the Destec gasification process. The objective was to establish base cases for commercially available (or nearly available) power plant systems having a nominal size of 400 megawatts (MWe). The simulation models are based on previous simulations (ASPEN Archive CMS Library), available literature information, and Destec published reports. The COE estimates were based on data from the EG&G Cost Estimating Notebook and several contractor reports. These cases can be used as starting points for the development and analysis of proposed advanced power systems.

The cases developed have the following common process sections:

- Coal Slurry Prep - based on Illinois #6 coal, 66.6% solids.
- Destec Gasification - two stage, entrained flow, oxygen-blown, slagging gasifier.
- Air Separation Unit (ASU) - high pressure process integrated with the gas turbine.
- “G” gas turbine -W501G modified for coal derived fuel gas.
- Three pressure level subcritical reheat Steam Cycle
  - (1800 psia/1050°F/342 psia/1050°F/ 35 psia).

The approach used for gas cleanup accounts for the major differences between the two cases. For sulfur removal, Case 1 uses cold gas cleanup (CGCU) and Case 2 uses transport desulfurization hot gas cleanup (HGCU). The syngas gas cooler section following the gasifier (and integrated with the gasifier and other heat exchangers) is used for generating high-pressure superheated steam. This section is followed by a cyclone that captures particulates for recycle to the gasifier. The cooled raw fuel gas leaves the filter at a temperature of 650°F for Case 1 and 1004°F for Case 2. In Case 1, the raw fuel gas is further cooled (304°F) and scrubbed and then sent to a gas cooling / heat recovery section before entering the CGCU section. In Case 2, the raw fuel gas enters a chloride guard bed prior to the HGCU section. Sulfur is recovered as elemental sulfur using the Claus process for Case 1 and as sulfuric acid using an acid plant for Case 2.

Process flow diagrams and material and energy balances summaries are shown in Figures 1-4 and COE summaries are given in Appendix A. In Table 1 the overall results obtained for power generation, process efficiency, and COE are compared for both cases.

Table 1 : Destec Gasifier IGCC Base Cases Summary

	CASE 1	CASE 2
Gasifier	Destec	Destec
Sulfur Removal	CGCU	HGCU
Coal Flowrate (Tons/day) Slurry Flowrate (Tons/day) Gas Turbine Power (MWe)	3123 4163 272.8	2944 3925 272.6
Steam Turbine Power (MWe)	172.2	171.1
Misc./Aux. Power (MWe)	44.4	43.3
Total Plant Power (MWe)	400.6	400.4
Efficiency, HHV (%)	45.0	47.6
Efficiency, LHV (%)	46.7	49.4
Total Capital Requirement, ($1000)	546,993	538,933
$/Kw	1,365	1,346
Net Operating Costs ($1000)	46,487	41,888
COE (mills/kWh)	42.3	40.4

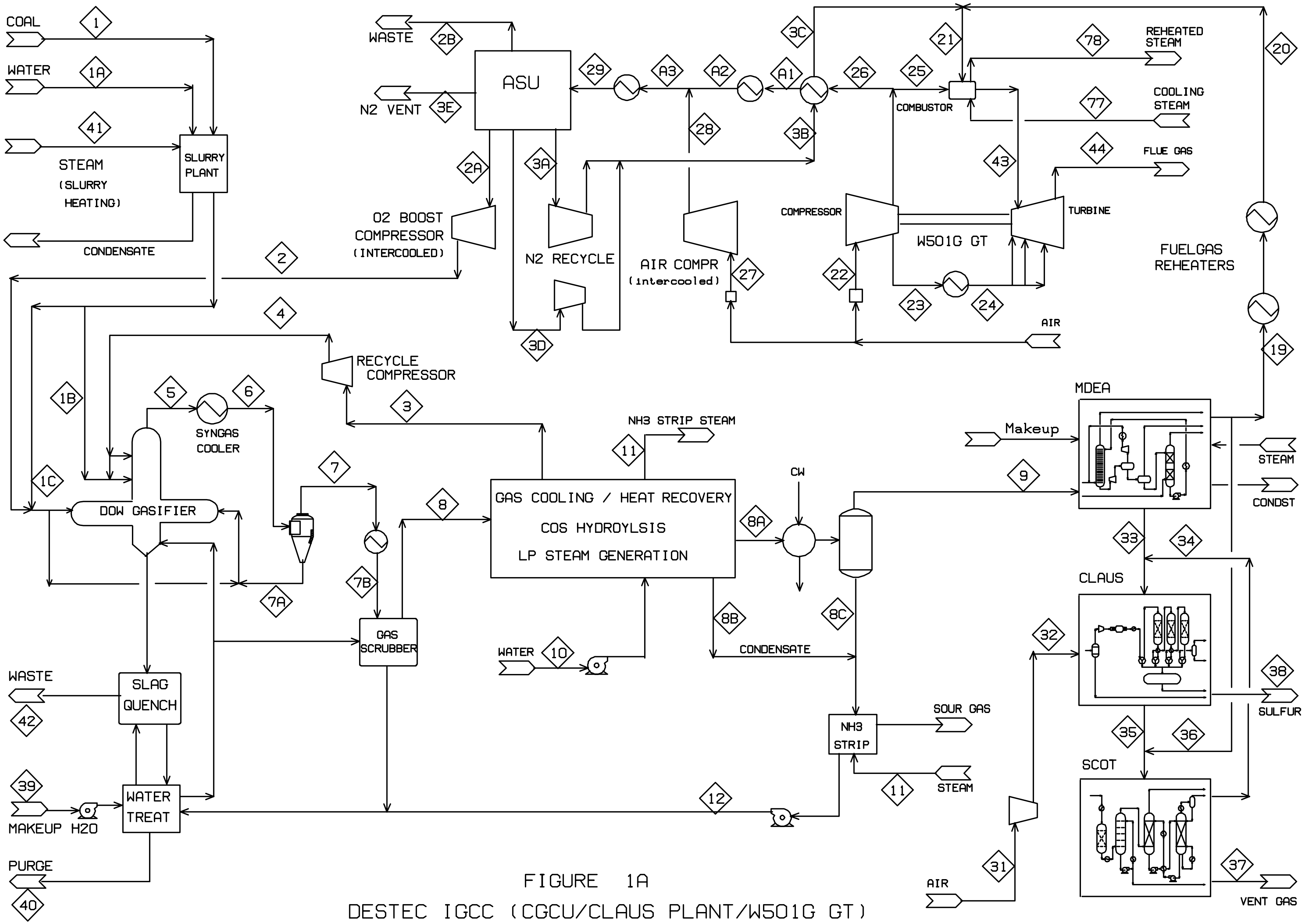


FIGURE 1A

DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

FIGURE 1B

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

SUMMARY:

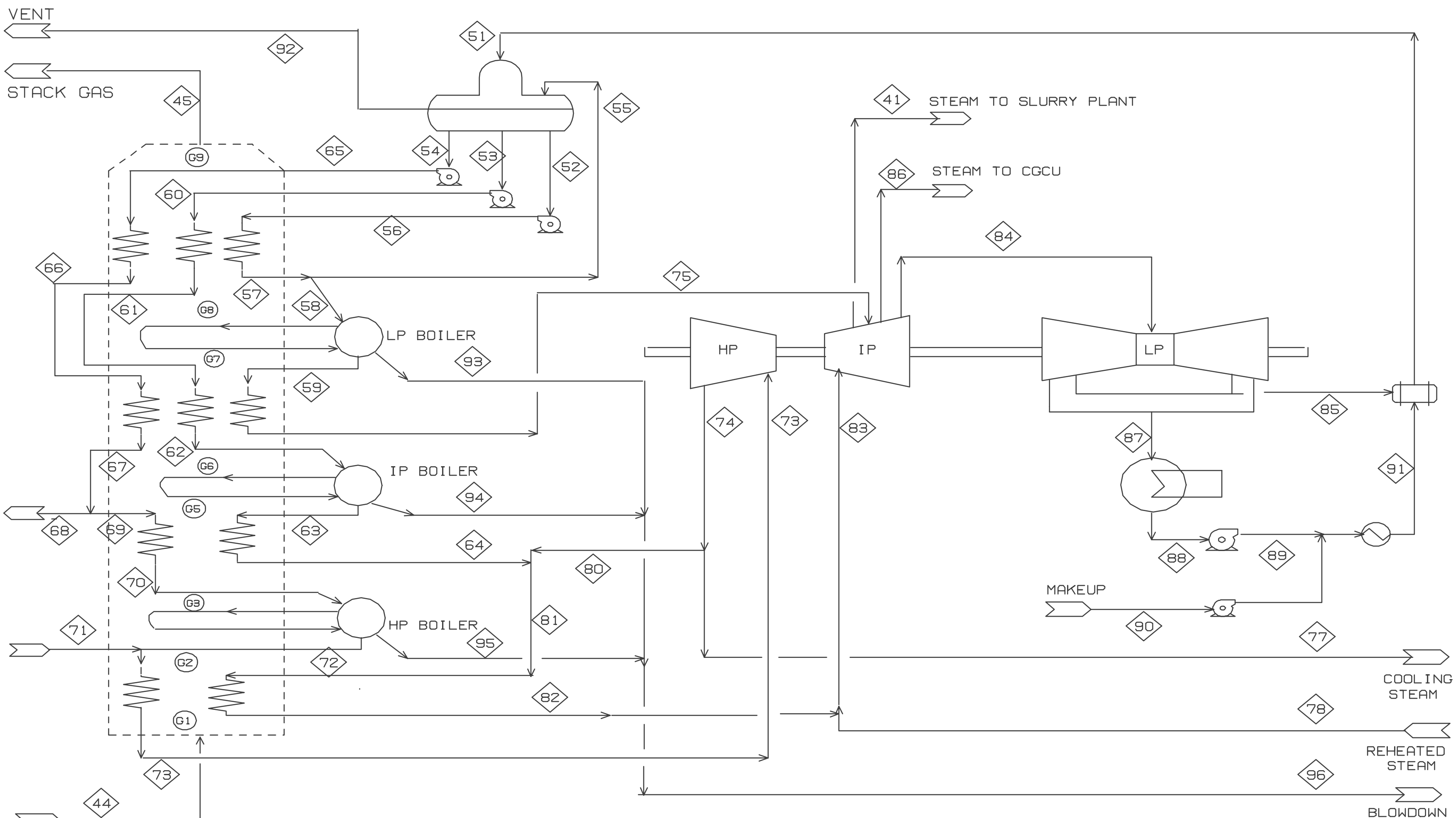
~~POWER~~	~~MWe~~	~~EFFICIENCY:~~	~~%~~
GAS TURBINE	272.8	HHV	45
STEAM TURBINE	172.2	LHV	46.7
MISCELLANEOUS	32		
AUXILIAR	12.4		
NET POWER	400.6		

STREAM	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4	5
FLOW (LB/HR)	260226	86709	72573	274362	197846	2990	197846	317975	358735	358735	40761	270868	141102	141103	670129
TEMPERATURE (F)	59	59	350	350	60	59	204.7	62	189.3	700	60	62	304.6	333.8	1900
PRESSURE (PSIA)	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	378	425	412
H (MM BTU/HR)	-814.7	-596.7	-153.1	-574.8	-0.9	-20.3	5	-3.5	7.4	54.1	-0.3	-3	-370.7	-369.2	-1164.4

STREAM	6	7	7A	7B	8	8A	8B	8C	9	10	11	12	19	20	21
FLOW (LB/HR)	670129	661340	8788	661340	705510	472085	92323	11380	460705	45000	45000	102871	424837	424837	783573
TEMPERATURE (F)	650	649.9	649.9	415	304.2	190	232.2	101.9	103	59	280	213	116	589.7	629.2
PRESSURE (PSIA)	403.8	394.5	394.5	390	380	354	354	20	349	14.7	37	470	340	330	294
H (MM BTU/HR)	-1519.1	-1506.8	-12.4	-1568	-1853.6	-978	-617.7	-73.3	-931.2	-309.7	-255.7	-690.7	-847.5	-770.3	-716.2

STREAM	22	23	24	25	26	A1	A2	A3	27	28	29	31	32	33	34
FLOW (LB/HR)	4320000	527109	527109	3363310	416102	416102	416102	830440	416102	414338	830440	14107	14107	32346	1976
TEMPERATURE (F)	59	813.3	600	813.3	813.3	370.4	216	210	59	203.9	190	59	161.2	142.1	70
PRESSURE (PSIA)	14.6	282.2	276.6	282.2	282.2	280.2	278	278	14.6	278	277	14.7	25	18.5	17.5
H (MM BTU/HR)	-180.3	76.7	47.9	489.6	60.6	13.8	-2.1	4.6	-17.4	6.7	0.5	-0.6	-0.2	-86.3	-6.9

STREAM	35	36	37	38	39	40	41	42	43	44	45
FLOW (LB/HR)	42121	6755	46900	6307	38680	87473	53025	34450	4146881	4673991	4673991
TEMPERATURE (F)	424	116	70	285	59	200	820.1	200	2582.2	1119.5	261
PRESSURE (PSIA)	26.7	340	17.5	14.7	14.7	15	150	15	268.5	15.2	14.7
H (MM BTU/HR)	-109.4	-13.5	-126.8	-0.7	-266.2	-585.9	-287.8	-114.7	-265.9	-1971.2	-3032.3



STEAM CYCLE
DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

FIGURE 2A

FIGURE 2B

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

STEAM CYCLE / HRSG PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61	62
FLOW (LB/HR)	53025	4673991	4673991	974779	269014	259543	697343	257282	269014	269014	11732	11615	259543	259543	259543
TEMPERATURE (F)	820.1	1119.5	261	203.8	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286	420
PRESSURE (PSIA)	150	15.2	14.7	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390	370.5
H (MM BTU/HR)	-287.8	-1971.2	-3032.3	-6525.4	-1797.2	-1733.9	-4658.8	-1700.9	-1797.1	-1778.4	-77.6	-66	-1733.5	-1715.7	-1679.1

STREAM	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78
FLOW (LB/HR)	256948	256948	697343	697343	697343	505841	191503	191503	505841	189588	695428	695428	11615	70000	70000
TEMPERATURE (F)	432.3	620	221.2	286	420	420	620	620	635	629.3	1050	606.7	420	606.7	1055.9
PRESSURE (PSIA)	352	350	2345.6	2228.3	2116.9	2116.9	2011.1	2011.1	1910.5	1910.5	1800	350	69.5	350	342
H (MM BTU/HR)	-1455	-1424.5	-4652.4	-4607.2	-4510.2	-3271.6	-1191.4	-1191.4	-2888.1	-1084.7	-3724.1	-3860.5	-65.3	-388.6	-371.8

STREAM	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94
FLOW (LB/HR)	625428	882376	882376	952376	849203	23299	61763	825904	825904	825904	125576	951480	6160	117	2595
TEMPERATURE (F)	606.7	610.6	1050	1050.4	482	350	596.5	88.8	87.9	87.9	80	178.3	217.3	305.3	432.3
PRESSURE (PSIA)	350	350	342	342	35	17	60	0.7	0.7	40	14.7	17	16.3	72.5	352
H (MM BTU/HR)	-3472	-4896.4	-4689.6	-5061.4	-4746.9	-131.7	-341.9	-4825.3	-5624.5	-5624.4	-856.2	-6393.7	-35.2	-0.8	-16.8

STREAM	95	96	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	1915	4628	4673991	4673991	4673991	4673991	4673991	4673991	4673991	4673991
TEMPERATURE (F)	629.3	213	1119.5	763	686.6	623.4	452	338.9	329.8	260.1
PRESSURE (PSIA)	1910.5	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-11.9	-29.4	-1971.2	-2426.8	-2521.6	-2599.2	-2806.6	-2940.8	-2951.6	-3033.4

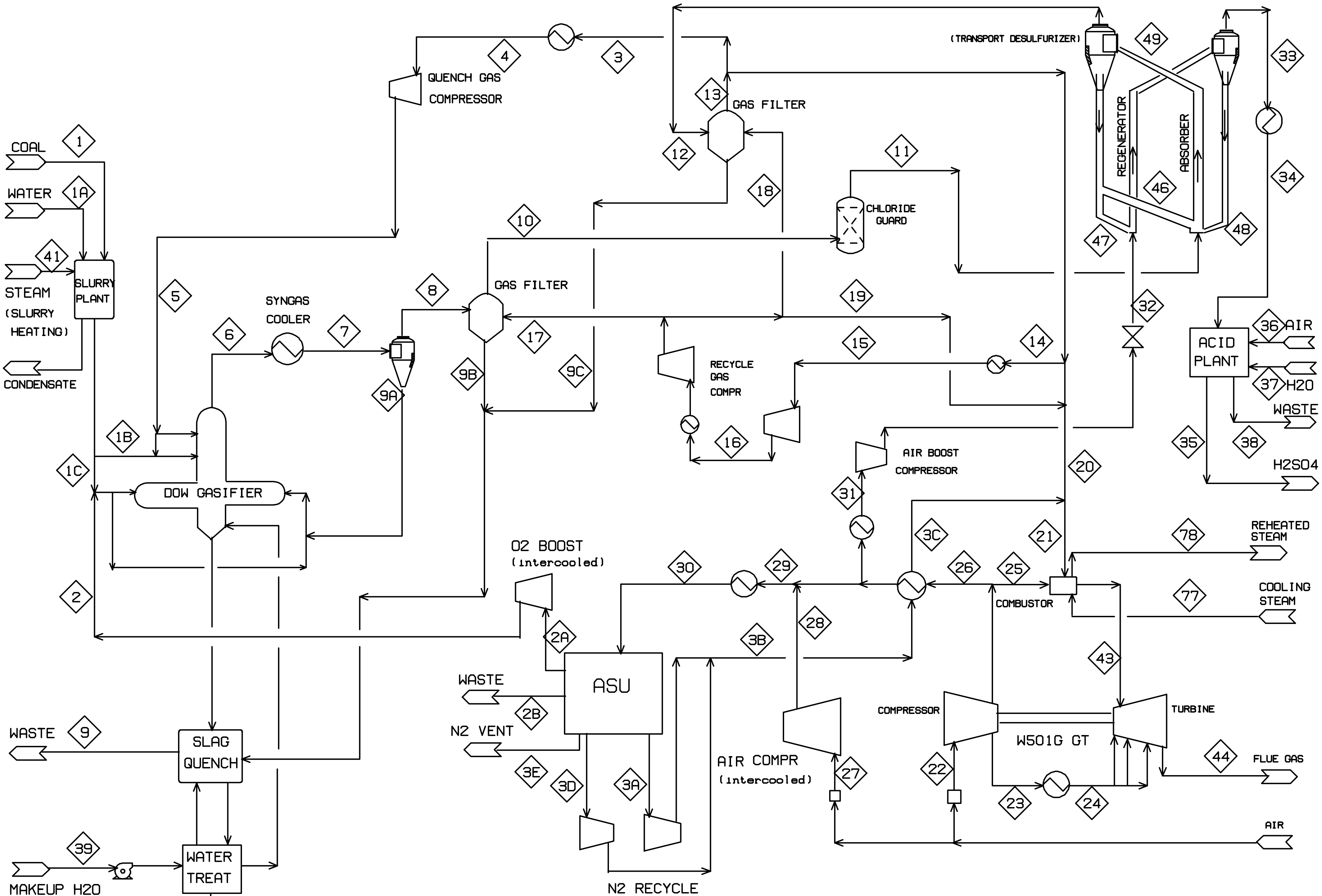


FIGURE 3A

DESTEC IGCC (HGCU/ACID PLANT/W501G GT)

FIGURE 3B

DESTEC IGCC - (SYNGAS COOLER / HGCU / ACIDPLANT / 3 PRES STEAM CYCLE)

SUMMARY:

POWER	MWe	EFFICIENCY:		%
GAS TURBINE	272.6		HHV	47.6
STEAM TURBINE	171.1		LHV	49.4
MISCELLANEOUS	31			
AUXILIAR	12.4			
NET POWER	400.4			

STREAM	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4	5
FLOW (LB/HR)	245353	81753	68425	258681	189517	2823	189517	260592	299636	299636	39045	303460	166931	166931	166938
TEMPERATURE (F)	59	59	350	350	60	59	204.7	62	187.3	700	60	62	1053.2	300	360.3
PRESSURE (PSIA)	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	346	336	425
H (MM BTU/HR)	-768.2	-562.6	-146	-547.8	-0.9	-19.4	4.8	-2.8	6.1	45.3	-0.3	-3.3	-356.7	-406.9	-403.2

STREAM	6	7	8	9A	9B	9C	9	39	40	41	10	11	12	13	14
FLOW (LB/HR)	668707	668707	660421	8286	875	46	36520	29732	17272	50110	667559	666840	663762	667723	13354
TEMPERATURE (F)	1900	1004	1004	1004	997.1	1053.2	200	59	200	820.1	997.1	994.1	1057	1053.2	1053.2
PRESSURE (PSIA)	412	403.8	394.5	394.5	14.7	14.7	14.7	15	15	150	382.7	366	356	346	346
H (MM BTU/HR)	-1152.2	-1408.8	-1397.9	-10.9	-1.2	-0.1	-135.4	-204.6	-116.2	-272	-1416	-1416.1	-1417.3	-1426.8	-28.5

STREAM	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
FLOW (LB/HR)	13354	13354	8013	4006	1335	488773	788409	4320000	527109	527109	3321623	457790	397907	396217	794125
TEMPERATURE (F)	300	436.2	418.3	418.3	418.3	1051.5	952.5	59	812.7	600	812.7	812.7	59	203.7	341
PRESSURE (PSIA)	336	565.6	900	900	900	345	294	14.6	282.2	276.6	282.2	282.2	14.6	278	278
H (MM BTU/HR)	-32.6	-31.9	-19.2	-9.6	-3.2	-1044.8	-999.4	-180.3	76.8	48	483.7	66.7	-16.6	6.5	30.3

STREAM	30	31	32	33	34	35	36	37	38	43	44	46	47	48	49
FLOW (LB/HR)	794125	59882	59882	62927	62927	18585	13188	3331	60858	4110031	4637140	4390982	487887	484842	5542664
TEMPERATURE (F)	190	120	167	1420.4	850	100	59	59	100	2583	1125.6	1055	1055	1420.4	1057.9
PRESSURE (PSIA)	275	275.2	371	361	344	16	14.7	14.7	16	268.5	15.2	356	356	361	361
H (MM BTU/HR)	0.6	-1.9	-1.1	-5.7	-14.9	-23.3	-0.6	-22.9	-1.9	-554.2	-2259.1	-15077.6	-1675.3	-1672.7	-18166.3

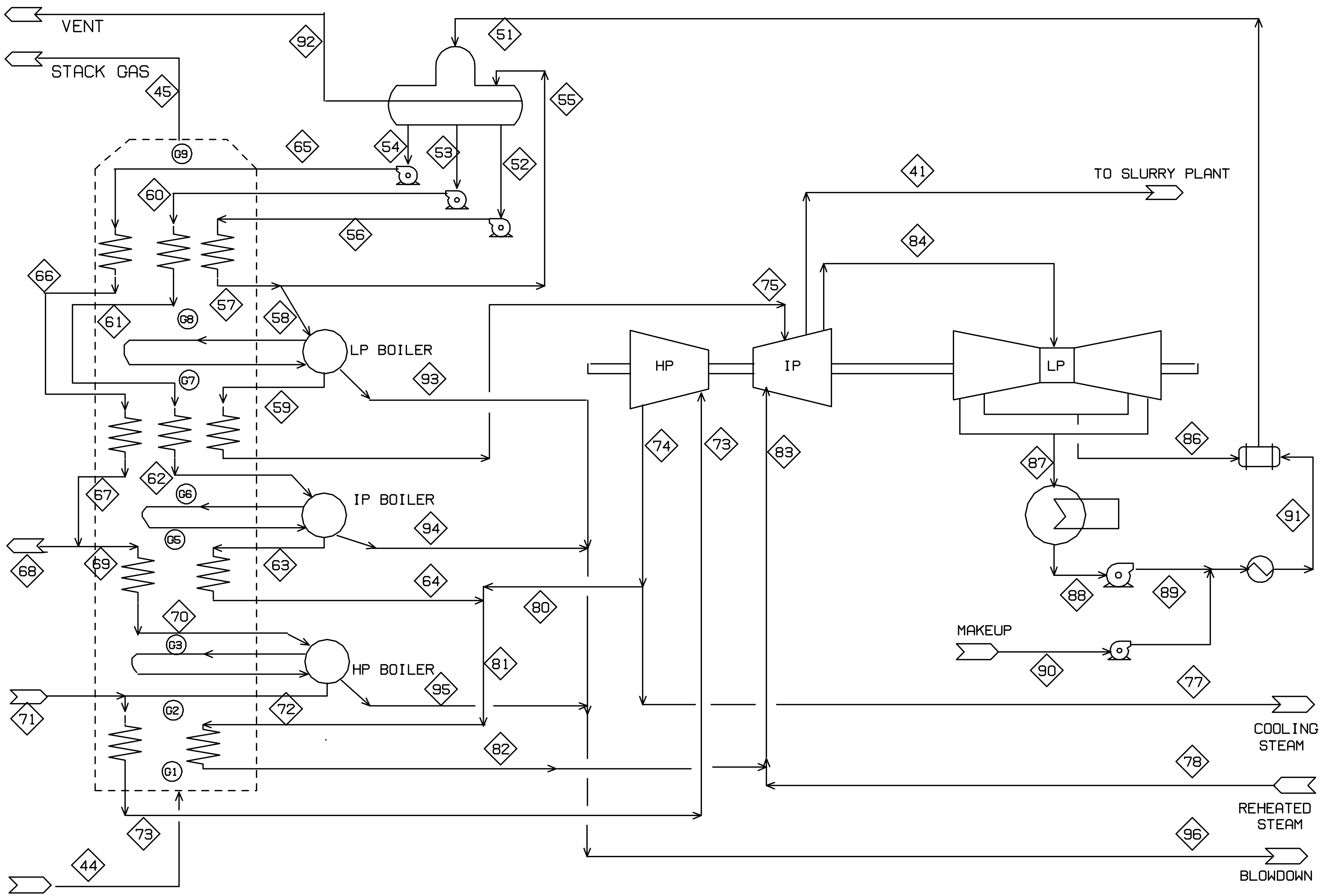


FIGURE 4A - STEAM CYCLE

FIGURE 4B

DESTEC IGCC - (SYNGAS COOLER / HGCU / ACID PLANT / 3 PRES STEAM CYCLE)

STEAM CYCLE / HRSG PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61	62
FLOW (LB/HR)	50110	4637140	4637140	950123	262206	263059	669625	250771	262206	262206	11435	11321	263059	263059	263059
TEMPERATURE (F)	820.1	1125.6	258.2	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286	420
PRESSURE (PSIA)	150	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390	370.5
H (MM BTU/HR)	-272	-2259.1	-3333.4	-6359.2	-1751.7	-1757.4	-4473.6	-1657.8	-1751.7	-1733.4	-75.6	-64.4	-1757	-1738.9	-1701.8

STREAM	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78
FLOW (LB/HR)	260428	260428	669625	669625	669625	437666	231959	231959	437666	229639	667305	667305	11321	70000	70000
TEMPERATURE (F)	432.3	620	221.2	286	420	420	420	620	635	629.3	1049.3	606.2	420	606.2	1055.4
PRESSURE (PSIA)	352	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1911	1910.5	1800	350	69.5	350	342
H (MM BTU/HR)	-1474.7	-1443.8	-4467.5	-4424.1	-4330.9	-2830.7	-1500.2	-1443.1	-2498.9	-1313.9	-3573.8	-3704.6	-63.7	-388.6	-371.8

STREAM	80	81	82	83	84	86	87	88	89	90	91	92	93	94	95
FLOW (LB/HR)	597305	857733	857733	927733	888944	51176	837768	837768	837768	61179	898947	6004	114	2631	2320
TEMPERATURE (F)	606.2	610.4	1050	1050.4	481.9	350	88.8	87.9	87.9	80	145.7	217.3	305.3	432.3	629.3
PRESSURE (PSIA)	350	350	342	342	35	17	0.7	0.7	40	14.7	17	16.3	72.5	352	1910.5
H (MM BTU/HR)	-3316	-4759.8	-4558.6	-4930.5	-4969	-289.2	-4894.6	-5705.3	-5705.2	-417.1	-6070.1	-34.3	-0.8	-17	-14.4

STREAM	96	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	5065	4637140	4637140	4637140	4637140	4637140	4637140	4637140	4637140
TEMPERATURE (F)	213	1125.6	782.5	690.3	618.8	445.1	335	326.1	258.2
PRESSURE (PSIA)	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-32.1	-2259.1	-2699.3	-2814.1	-2902.1	-3112.3	-3243.2	-3253.7	-3333.4

1. Process Descriptions

Two IGCC Base Cases have been developed based on the Destec gasification process. The cases differ primarily in how the generated fuel syngas is cooled and in the gas cleanup sections. The Destec process uses a two stage, oxygen-blown, entrained flow, slagging gasifier. Both cases use a raw gas cooler (which is integrated with the gasifier and other heat exchangers) to generate high pressure superheated steam and a cyclone to remove particulates, which are recycled to the gasifier. The syngas leaves the cyclone at 650°F for Case 1 and at 1004°F for Case 2. For Case 1, the fuel gas is further cooled and scrubbed before entering a cold gas cleanup unit (CGCU) using the MDEA/Claus/Scot process for sulfur removal and recovery. For Case 2, fuel gas enters a chloride guard bed that is followed by a hot gas cleanup unit (HGCU) using a transport absorber/regenerator process. The sulfur dioxide generated from the transport regenerator is sent to an acid plant for producing sulfuric acid. Power is recovered for both cases using a modified W501G gas turbine and a three-pressure level reheat steam cycle.

The composition for the as-received Illinois #6 Coal fed to the slurry process is listed below.

Proximate Analysis:	(Wt. %)	(Wt. %, dry)
Moisture	11.12	
Ash	9.70	10.91
Volatiles	34.99	39.37
Fixed Carbon	44.19	49.72
	100	100
HHV (Btu/lb)	11,666	13,126

Ultimate Analysis:	(Wt. %)	(Wt. %, dry)
Moisture	11.12	
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
	100	100

Additional features for the two cases are given in following sections. In Table 2, the processes used are compared.

Table 2 : Destec IGCC Base Cases Process Section Comparison

PROCESS SECTION	CASE 1	CASE 2
Destec Gasifier Exit Temp / Press	1900°F / 412 psia	1900°F / 412 psia
Air Separation Plant Inlet Air Press (psia): O2 / N2 Press (psia):	50 % Integration GT 277 472 / 300	50 % Integration GT 277 472 / 300
Solid Waste **Particulates**	Slag Quench Filter, Scrubbers	Slag Quench Ceramic Filter
Low Temp Gas Cooling/Heat Recovery	COS Hydrolysis, BFW Heating, Fuel Gas Reheating	N/A
Chloride/NH3 Removal	Water Treatment	Chloride Guard Bed
Sulfur Removal	CGCU-MDEA/CLAUS/SCOT (elemental sulfur)	HGCU - Transport Desulfurization, Acid Plant (sulfuric acid)
Clean Fuel Gas / Gas Addition	N2 Recycle from ASU	N2 Recycle from ASU
Gas Turbine - Power (MWe): - PR / TIT (F):	modified W501G 272 (target) 19.37 / 2583	same as Case 1
Steam Cycle - Turb Press: HP/IP/LP - Superheat/Reheat - Exhaust LP Turb - HRSG Stack Temp	3 Pressure Level/Reheat 1800 / 342 / 35 (psia) 1050°F/ 1050°F 0.67 psia 260 °F	same as Case 1

1.1 Destec Gasifier

The gasifier is a two stage, slurry feed, pressurized, oxygen-blown, entrained-flow slagging reactor. The coal/water slurry feed, prepared using finely ground coal, (Illinois #6 for the cases considered), is pressurized by pumping and then preheated using steam. Approximately 80% of the slurry is gasified / combusted with oxygen in the first (lower) stage using two burners positioned on the opposing ends of this horizontal cylindrical section. This geometry is designed to provide a means for thoroughly mixing the reactants and to disperse this mixture so that a high carbon conversion is realized. Highly exothermic reactions occur that result in temperatures above the ash fusion point of 2400 - 2600 °F. The raw fuel gas flows upward into the second (upper) stage of the gasifier while the molten slag flows down the walls of the gasifier and passes into a slag quench bath. In this upper vertical cylindrical stage, the remaining coal slurry is fed using part of the cooled product fuel gas recycle stream and additional gasification occurs. The majority of the fuel gas recycle enters near the gasifier exit as a means of quenching the exiting raw fuel gas to a temperature below the melting point of any entrained ash particles. This avoids sticky solids entering the raw gas cooler. The raw gas cooler further cools the gas and generates high-pressure steam, which is sent to the steam cycle. Solids are recovered in the following particulate filter and recycled back to the reactor. Figures 1 and 3 illustrate the gasification section and major process streams relationship to other process sections. In Table 3, gasifier conditions are listed for the two Destec IGCC cases.

1.2 Air Separation Plant (ASU)

For both cases, an advanced high pressure cryogenic oxygen plant that takes advantage of the air (278 psia) extracted from the W501G gas turbine is employed. This advanced design is available due to recent improvements made to the conventional air separation technology which operates efficiently only to about an air supply pressure of 170 psia. The advanced ASU by operating at a higher pressure results in the oxygen and nitrogen products being available from the cold box at higher pressures than in a conventional ASU. This reduces costs for the further compression of these streams. For operational flexibility, (in startup and turndown), the present cases consider that the air is supplied, in equal amounts (50%), from a bleed from the gas turbine compressor exhaust and as air supplied directly using a boost compressor. The GT Compressor bleed air preheats a nitrogen recycle stream (98.9% purity) being sent to the gas turbine to assist in NOX control and to increase the flowrate through the gas turbine expander. The amount of nitrogen recycled is adjusted for each case to yield a net gas turbine power of approximately 272 MWe. The amount of nitrogen recycle is about 57% for Case 1 and 50% for Case 2. The oxygen stream (95% purity) is supplied to the Destec gasifiers. Table 4 lists some of the key parameters for the ASU designs for the two cases.

Table 3. Destec IGCC Base Cases - Gasifier Conditions

	CASE 1 CGCU	**CASE 2 HGCU**
Flowrate (tons/day)		
- Coal to Prep Plant:	3123	2944
- Slurry Water:	1040	981
- Coal Slurry:	4163	3925
Gasifier Exit Conditions		
- Pressure (psia):	412	412
- Temp (°F)	1900	1900
First Stage Flowrates (lb/hr)		
- Coal Slurry Feed:	274362	258681
- Oxidant:	197846	189517
- Recycle Fines:	8788	8286
- Slag (before Quench):	25519	23140
Second Stage Flowrates (lb/hr)		
- Coal Slurry Feed:	72573	68425
- Recycle Quench Gas:	141103	166938*
- Raw Fuel Gas:	670129	666794
Heating Value (Btu/Scf) (from gasifier)		
- LHV	232	234
- HHV	248	250

(* note: temperature is higher and composition differs slightly for Case 2)

Table 4. Destec IGCC Base Cases - ASU Summary

	CASE 1 CGCU	CASE 2 HGCU
% Air from Gas Turbine	50	50
Air Inlet Press (psia)	277	277
Total Air Flowrate (lb/hr)	830,440	794,125
Oxidant Stream		
- Flowrate (lb/hr):	197,846	189,517
- Purity (mole % O2):	95.0	*
- ASU Press (psia):	92	*
- Boost Compr Press (psia):	472	*
Nitrogen Stream		
- Flowrate (lb/hr):	629,604	603,098
- Purity (mole % N2):	98.9	*
- ASU Press (psia):	91 / 265	*
- Boost Compr Press (psia):	300	*
- % Recycled to GT:	57	50
- GT Recycle Temp (F):	700	*
Power Requirements (MWe)		
- Air Compressor:	18.1	17.3
- O2 Boost Compressor:	4.8	4.5
- N2 Boost Compressors:	5.7	4.7

1.3 Gas Cooling Section - Case 1

For Case 1, the raw fuel gas from the particulate filter enters a heat exchanger used to partially reheat the clean fuel gas stream from the CGCU section. A gas scrubber follows that reduces the temperature to 304°F and removes fines. A portion of the cooled raw fuel gas stream, approximately 20%, is split off and recycled to quench the hot raw fuel gas stream exiting the gasifier. The remaining raw fuel gas proceeds into a catalytic hydrolyzer which converts the carbonyl sulfide (COS) to hydrogen sulfide. Further cooling occurs in several heat exchangers to

220°F, before the raw fuel gas enters a scrubber, which reduces the temperature to 100°F. Any hydrogen chloride, ammonia, and remaining particulates are assumed to be in the scrubber water discharge that is sent to a water treatment unit. The cooled fuel gas is sent to the CGCU section for sulfur removal.

1.4 Cold Gas Cleanup Unit (CGCU) - Case 1

The MDEA/Claus/SCOT process is used for cold gas cleanup and sulfur recovery. Refer to Figure 1 for a conceptual idea of the equipment setup for each process. In the MDEA step, the cooled gas from the gas cooling section enters an absorber where it comes into contact with the MDEA solvent. As it moves through the absorber, almost all of the H_2S and a portion of the CO_2 are removed. The solute-rich MDEA solvent exits the absorber and is heated by the solute-lean solvent from the stripper in a heat exchanger before entering the stripping unit. Acid gases from the top of the stripper are sent to the Claus/SCOT unit for sulfur recovery. The lean MDEA solvent exits the bottom of the stripper and is cooled through several heat exchangers. It is then cleaned in a filtering unit and sent to a storage tank before the next cycle begins.

The Claus process is carried out in two stages. In the first stage, about one-quarter of the gases from the MDEA unit, which exits at 142°F, are mixed with the recycle acid gases from the SCOT unit and are burned in the first furnace. The remaining acid gases are added to the second-stage furnace, where the H_2S and SO_2 react in the presence of a catalyst to form elemental sulfur. The gas is cooled in a waste heat boiler and then sent through a series of reactors where more sulfur is formed. The sulfur is condensed and removed between each reactor. A tail gas stream containing unreacted sulfur, SO_2, H_2S, and COS is sent for further processing in the SCOT unit. This tail gas is heated before entering a reactor where SO_2 converts to H_2S with the aid of a cobalt-molybdate catalyst. The effluent is cooled by waste heat boilers and direct quench before being sent to an absorber column where the H_2S is removed. The H_2S rich stream is sent to the regenerator before being recycled to the absorber. The acid gas from the regenerator is recycled to the Claus step. Further information is provided in Table 5.

Table 5. Destec IGCC Base Cases - CGCU Conditions

	CASE 1 CGCU
Sulfur Balance: (lb sulfur/hr)	
- MDEA Feed	6375.8
- Acidgas to Claus	6316.0
- Cleaned Fuel Gas	58.8
- Sulfur Product	6307.0
- SCOT Vent Gas	9.8
Key Conditions	
- PPMV to CGCU	8587
- PPMV Clean Fuel Gas	83
- Sulfur Recovery (weight %)	99.1
- Steam Requirements (lb/hr)	61763
- Power Requirements (kWe)	777

1.5 Chloride Guard Bed / Fine Particulate Removal - Case 2

For Case 2, the raw fuel gas exits the raw gas cooler (at 1004°F) and is sent through a cyclone and a gas filter for particulate removal. It is then sent to the chloride guard bed section for hydrogen chloride removal. These guard beds, containing commercial grade Nahcolite, capture the chloride and any other halogens. The beds will require periodic treatment and operate with several on-line while others are being renewed. The resulting fuel gas stream is sent to the HGCU section for sulfur removal. A gas filter is used following the HGCU section to guard against any fine particulates left (or generated in HGCU) in the clean fuel gas sent to the gas turbine.

1.6 Transport Desulfurization HGCU - Case 2

The representation for this section was based on information provided by L. Bissett (FETC). FETC is currently developing an on-site (Morgantown) pilot plant to test this HGCU option for a number of sorbents. In the HGCU section, the transport absorber operates at an inlet pressure of 366 psia. A zinc based sorbent is used. The reaction occurs as a simple exchange between the ZnO portion of the sorbent and the sulfur. The cleaned fuel gas exits at 1057°F and enters a gas filter to capture any particulates. The particulate free fuelgas stream is divided between a recycled stream (25%), used to quench the raw fuel gas, a bleed stream (2%), used to pressurize gas filters, and the fuelgas stream (73%) sent to the gas turbine combustor.

The absorber consists of a riser reaction section, a solids/gas separation vessel, and a solids return dipleg. The riser operates at a high void fraction of approximately 95 percent. The large amount of sorbent recirculation results in only a small change in the sorbent sulfur content through this section. A slip stream of approximately 10 percent of the sorbent stream exiting the separation vessel is sent to a regenerator riser, while the remaining portion is combined with regenerated sorbent and sent back for the next absorber cycle. The regenerator is assumed to remove only a portion of the absorbed sulfur. This removal matches the sulfur that is removed from the raw fuel gas that enters the absorber. Since only a small amount of sulfur reacts, the regenerator exit temperature can be controlled to a value of approximately 1400°F by adjusting the amount of air (from GT) used. The regenerator waste gas stream is recycled to the sulfuric acid plant for SO_2 removal. HGCU conditions are listed in Table 6.

Table 6. Destec Gasifier IGCC Base Case 2 - HGCU Conditions

Sulfur Balance Information:	Flowrate (lb/hr)	
Sulfur in Raw Fuel Gas	6152.4	
Sulfur in Regenerator Waste	6076.8	
Sulfur in Clean Fuel Gas	10.9	
(ASPEN Convergence Error Sulfur %)	1.05 %	
PPMV of Sulfur in Raw Fuel Gas	5683.1	
PPMV of Sulfur in Clean Fuel Gas	10.0	
HGCU Sulfur Capture Eff. (weight %)	99.8	
Mole % SO_2 in Regenerator Waste	9.6	
Regenerator Exit Gas Temp (°F)	1420	
Regenerator Air Temp (°F)	167	
HGCU Solids:	**Flowrate (1000 lb/hr)**	**Sorbent Utilization***
To Absorber Rise	4876	0.443
From Absorber Separator	4879	0.450
To Regenerator Riser	488	0.450
From Regenerator. Separator	485	0.385
Ratio (Solids to Absorber/Solids to Regenerator):	10	

* Sorbent utilization = moles of ZnS/total moles of ZnX compounds

1.7 Sulfuric Acid Plant - Case 2

In the simulation model, no process details were used to represent the sulfuric acid plant. The only item taken into consideration was the acid plant power consumption rate of 46 watts per lb/hr SO_2 fed to the plant. The sulfuric acid production was based on closing the sulfur balance. However, the following process was used as a basis for the cost analysis.

The regeneration gas from the desulfurization section enters the sulfuric acid plant and passes over a vanadium catalyst stage at temperatures between 800 and 825°F. The temperature is allowed to increase adiabatically as the SO_2 is converted to SO_3. After the reaction is 60 to 70 percent complete, it is stopped. The gas stream is then cooled in a waste heat boiler and passed through subsequent stages of catalyst until the temperature of the gas passing through the last stage is below 800 °F. This process usually requires two to three stages of catalyst. Once cooled, the gas stream is sent to an intermediate absorber tower where some of the SO_3 is removed with 98 percent sulfuric acid. The gases leaving the absorber are reheated and passed over the remaining catalyst stages in a converter. The gases are again cooled and sent to a final absorber tower. Upon exiting the final absorber, the gases are vented to the atmosphere. The conversion of SO_2 to SO_3, and subsequently Sulfuric Acid, using this process is about 99.8 percent.

1.8 Gas Turbine

Both cases were based on using a modified W501G gas turbine that was integrated with the Air Separation Unit (ASU). From the compressor exhaust, a bleed stream is used to supply 50% of the air supply needed for the ASU. An additional bleed, 14% of the compressor discharge air, is chilled to 600°F and used for cooling in the turbine expander. Heat recovered from the air cooler is used in the steam cycle. For Case 2, the compressor discharge also supplies air for use in the HGCU regenerator. The remainder of the compressor discharge air is used to combust the clean fuel gas. The ASU returns a nitrogen stream to the gas turbine combustor to assist in NOX control and to increase the flowrate and the power generated in the turbine expander. The nitrogen recycle flowrate is set by requiring that the gas turbine power generated equals approximately 272 MWe. Combustor duct cooling is accomplished using intermediate pressure steam supplied from the steam bottoming cycle. This reheated steam is returned to the steam cycle. The combustor exhaust gases enter the expander (2583°F, 269 psia), where energy is recovered to produce power.

The original turbine design specifications are based on a natural gas fuel rather than a coal derived syngas. The syngas's significantly lower heating value when compared to natural gas requires a higher flow rate to obtain the desired turbine firing temperature. To allow for the higher flow rate, an increase in the first nozzle areas will be required. The original combustor will also be replaced with a modified design to handle the lower BTU syngas. In the cases considered, the syngas composition varies depending on the fuel processing prior to the gas turbine and the amount of nitrogen recycled from the ASU. In Table 7, the fuel gas composition for each case is listed both with and without the nitrogen stream addition. In Table 8, the gas turbine conditions are listed for the two Cases.

Table 7. DESTEC IGCC Base Cases - Fuel Gas Composition (Mole %)

	(No Nitrogen Recycle from ASU)		(Nitrogen Recycle from ASU	
DESTEC Gas Cleaning	**CASE 1 CGCU**	**CASE 2 HGCU**	**CASE 1 CGCU**	**CASE 2 HGCU**
Mole %:				
O2	-	-	0.2	0.2
N2	1.1	0.9	37.5	30.3
Ar	0.8	0.7	0.6	0.6
H2	38.8	32.5	24.6	22.7
CO	50.3	43.5	31.8	30.5
CO2	8.5	8.6	5.4	6.0
H2O	0.5	13.6	0.3	9.6
CH4	0.1	0.1	817 PPMV	911 PPMV
H2S	75 PPMV	9 PPMV	47 PPMV	7 PPMV
COS	9 PPMV	0.5 PPMV	5 PPMV	0.4 PPMV
NH3	-	49 PPMV	-	35 PPMV
Heating Value (HHV) (Btu/Scf)	289	246	181	173

Table 8. Destec IGCC Base Cases - W501G Gas Turbine Conditions

Destec Gas Cleaning	**CASE 1 CGCU**	**CASE 2 HGCU**
Pressure (psia)		
- to Filter	14.7	* (Same as Case 1)
- Compressor inlet	14.57	*
- Compressor outlet	282	*
- Combustor exit	269	*
- Expander exhaust	15.2	*
Pressure Ratio	19.4	*
Flowrates (lb/hr)		
- Compr inlet Air	4320000	*
- Fuel Gas	424827	488773
- Nitrogen Recycle	358375	299636
- Bleed Air to ASU	416102	397907
- Bleed Air to HGCU	N/A	59882
- Air Cooling Bleed	527,109	*
- Air Compr Leakage	13478	*
- Steam Combustor Duct Cooling	70000	*
- Expander Exhaust Gas to HRSG	4673990	4637140
Temperature (°F)		
- Inlet Air	59	*
- Compressor outlet	813	*
- Nitrogen Recycle	700	*
- Fuel Gas	590	1052
- Combustor exhaust	2612	*
- Turbine inlet	2582	*
- Turbine exhaust	1119	1126
Power (MWe)		
- Compressor	-237.1	-273.2
- Expander	513.8	513.7
- Generator Loss	-3.9	-3.8
- Net Gas Turbine	272.8	272.6

1.9 Steam Cycle

The steam cycle used for the two Cases is based on a design by D. Turek (ABB Power Plant Laboratories). Pressure drops and steam turbine isentropic efficiencies were based on information from a study by Bolland[1]. The cycle is a three-pressure level reheat process. Major components include a heat recovery steam generator (HRSG), steam turbines (high, intermediate, and low pressure), condenser, steam bleed for gas turbine cooling, steam bleed for coal slurry heating, recycle water heater, and deaerator. The differences are related to the heat integration possible with the gasifier island sections. These include:

- The raw fuel gas is cooled to 650°F for Case 1 but only to 1004°F for Case 2 in the raw gas cooler that follows the gasifier. This reduces the amount of high-pressure steam generated in this exchanger.
- For Case 1, low-pressure steam is supplied for use in the MDEA and SCOT sections of the CGCU process. This steam is extracted from the intermediate pressure steam turbine area at a pressure of 60 psia.
- For Case 2, which uses HGCU, the available heat for condensate reheating is not sufficient to obtain the deaerator design inlet temperature of 205°F. To obtain the required temperature, a bleed of low-pressure steam is extracted from the low-pressure steam turbine area and mixed with the condensate.

In Figures 2 and 4 the steam cycle and process flows are provided for the two cases. The primary heat recovered is from the exhaust gas stream of the gas turbine and from the raw fuel gas exiting the gasifier to the raw gas cooler. Additionally, heat is integrated from the gas turbine cooling air chiller, from recycle gas coolers, and from several gasifier island gas coolers. Steam generation occurs at the three pressure levels of 72.5 psia, 353 psia, and 1911 psia in the HRSG. The cycle includes a parallel superheating/reheating section that raises the temperature to 1050°F for both the high-pressure steam and for the combined intermediate pressure steam and high-pressure turbine exhaust steam. Steam for the gas turbine combustor duct cooling is extracted from the HP turbine at a pressure of 350 psia. The return steam from the gas turbine combustor is combined with reheat steam and sent to the IP steam turbine. The LP steam turbine discharges at 89°F and 0.67 psia. The steam cycle conditions are summarized in Table 9.

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1 "A Comparative Evaluation of Advanced Combined Cycle Alternatives", Transactions of the ASME, April 1991.

Table 9. Destec IGCC Base Cases - Steam Cycle Conditions

HRSG Stack Gas Temperature:	260 °F
Deaerator Vent:	0.5% of inlet flowrate
LP,IP, and HP drum blowdown:	1.0% of inlet flowrate
Pressure drops:	5% of inlet (except IP superheater - 2 psia and line Drop before HP turbine - 15 psia)
High Pressure Turbine Inlet:	1800 psia / 1050 °F
Intermediate Pressure Turbine Inlet:	342 psia / 1050 °F
Low Pressure Turbine Inlet:	35 psia
Low Pressure Turbine Exhaust:	0.67 psia

Pressure Level	**Steam Conditions**		**HRSG Approach Delta Temp (°F)**	
	Pressure (psia)	**Saturation Temp (°F)**	**CASE 1**	**CASE 2**
Low	72.5	305	25	18
Intermediate	352	432	20	13
High	1911	629	58	61

Power Production (MWe)	**CASE 1 CGCU**	**CASE 2 HGCU**
Steam Turbines	174.18	173.66
Generator Loss	-2.62	-2.60
Net Steam Turbines	172.18	171.06
Pumps	-2.04	-1.97

1.10 Power Production

An auxiliary power consumption is assumed as 3 percent of the total power production by the Gas Turbine and the Steam Turbines minus the power consumed by the miscellaneous pumps, expanders, compressors, and blowers. The power production and the overall process efficiency are listed in Table 10 for the two Destec IGCC cases.

Table 10. Destec IGCC Base Cases - Power Production

	CASE 1 CGCU	CASE 2 HGCU
Gas Turbine (MWe)	272.8	272.6
Steam Turbine (MWe)	172.2	171.1
Miscellaneous (MWe)	-32.0	-30.9
Auxiliary (MWe)	-12.4	-12.4
Plant Total (MWe)	400.6	400.4
Overall Process Efficiency (HHV, %):	45.0	47.6
Overall Process Efficiency (LHV, %):	46.7	49.4

2. Simulation Development

The Destec IGCC gasification section was developed based on information available in several reports issued by EPRI and from preliminary design information available from the DOE/PSI/Destec Energy sponsored Wabash River Coal Gasification Repowering Project. Specifically, the EPRI references included:

- EPRI Reports:
  - Evaluation of a Dow-Based Gasification-Combined Cycle Plant using Bituminous Coal, GS-6904, June 1990.
  - Evaluation of a 510-MWe Destec GCC Power Plant Fueled with Illinois #6 Coal, TR-100319, June 1992.
  - Coal Gasification Guidebook: Status, Applications, and Technologies, TR-102034, December 1993

The models for the gas turbine (W501G) and the steam cycle were based on previously developed ASPEN simulations. The remaining process sections (i.e. HGCU, CGCU, ASU, Acid Plant) were based on representations available in a number of earlier studies. A search of the ASPEN Archive CMS Library will provide example cases for these process sections.

The ASPEN PLUS (version 10.1) simulation codes are stored in the EG&G's Process Engineering Team Library.

3. Cost of Electricity Analysis

The cost of electricity for the Destec cases was performed using data from the EG&G Cost Estimating notebook and several contractor reports. The format follows the guidelines set by EPRI TAG. Details of the individual section costs are described below and are based on capacity-factored techniques. The COE spreadsheets are included in Appendix A. All costs are reported in 1st Quarter 1999 dollars.

3.1 Coal Slurry Preparation

The coal slurry preparation section includes costs for coal hoppers, feeders, conveyors, and sampling and feed systems. The coal flow rate in the Destec HGCU case is 2944 tons per day (Illinois #6 coal), resulting in a section cost of $25.1 million. The coal flow rate for the Destec CGCU case is 3123 tons per day, resulting in a cost of $26.1 million.

3.2 Oxygen Plant

The cost for the oxygen plant includes the air separation unit, the air precoolers, the oxygen compressors, the nitrogen compressors and the air compressors. Both systems use a high-pressure air separation unit. The oxygen plant for Case 2 produces 2274 tons per day oxygen with a cost of $45.5 million. The oxygen plant for Case 1 produces 2374 tons per day oxygen with a cost of $48.5 million.

3.3 Destec Gasifier

The cost for the gasification section includes the gasifier, the raw gas cooler, slag handling and particulate removal. The cases are based on one gasification train with a nominal capacity of 3000 tons per day. The major difference in the cost of the two cases is related to the different size gas cooler. The cost for Case 2 is $55.4 million. The cost for Case 1 is $61 million. A process contingency of 5 percent was added to the total plant cost based on the development of the gasifier.

3.4 Low Temperature Gas Cooling and COS Hydrolysis (Cold Gas case only)

The cost for the low temperature cooling and gas saturation section includes several heat exchangers, separators, and the hydrolyzer. The cost for the CGCU case is $13.6 million.

3.5 MDEA/ Claus/ SCOT Section (Cold Gas cases only)

The cost of the MDEA acid gas removal system includes the absorber column, the stripping column, heat exchanger and pumps. The cost for the Destec CGCU case is $5.2 million.

The cost for the Claus/SCOT sulfur recovery and tail gas treating units for the Destec CGCU case is based on 83 tons per day of sulfur entering the unit. The total cost for both units is $14 million.

3.6 Gas Conditioning (Hot Gas case only)

The gas conditioning section includes a cyclone, two gas filters, and chloride guard beds. The cost for the Destec HGCU is $14.9 million and is based on one process train. A process contingency of 10% was added to the total plant cost based on the development of the gas conditioning components.

3.7 Desulfurization Section (Hot Gas case only)

The cost for the transport desulfurization section was derived from a previous report[2]. This includes costs for sorbent hoppers, transport desulfurizer and cyclones. However, the previous report was for a polishing unit and it is unclear how no sulfur capture in the gasifier will affect the price of the unit or the amount of sorbent needed. The amount of sorbent used was based information from the Separations and Gasification Engineering Division of NETL. The cost for the Destec HGCU is $8.6 million and is based on one process train. A process contingency of 15% was added to the total plant cost based on the development of the desulfurization sections.

3.8 Acid Plant Section (Hot Gas case only)

The cost for the sulfuric acid plant is based on a Monsanto contact process. The unit produces 224 tons per day of sulfuric acid and costs $18.1 million.

3.9 Gas Turbine Section

The cost for the W501G gas turbine was derived from the Gas Turbine World 96 Handbook[3]. The cost from the handbook was $185/kW and included all the basic turbine components. A factor of 7% was added for modifications and installation. The gas turbine powers of 272.6 MW_e and 272.8 MW_e, for the Destec HGCU and CGCU, respectively, resulted in an approximate cost

2 "Advanced Technology Repowering," Final Report, Prepared for the U.S. Department of Energy, Morgantown Energy Technology Center, Prepared by Parsons Power Group, Inc. May 1997

3 Gas Turbine World Performance Specifications, annual issue, Pequot Publishing Inc., Fairfield Connecticut.

of $54 million. A process contingency of 5% was added to the total plant cost based on the development of the modified gas turbines.

3.10 HRSG/ Steam Turbine Section

The cost for the steam cycle is based on a three-pressure level steam cycle. The Destec HGCU steam turbine power is 171.1 MW_e, with a combined section cost of $48 million. The Destec CGCU steam turbine power is 172.2 MW_e, with a combined section cost of $48.2 million.

3.11 Bulk Plant Items

Bulk plant items include water systems, civil/structural/architectural, piping, control and instrumentation, and electrical systems. These were calculated based on a percentage of the total installed equipment costs. The percentages in parenthesis are for the hot-gas cleanup process, which has a lower water requirement, and therefore, a smaller percentage for piping and water systems. The following percentages were used in this report.

Bulk Plant Item	% of Installed Equipment Cost
Water Systems	7.1 (5.1)
Civil/Structural/Architectural	9.2
Piping	7.1 (5.1)
Control and Instrumentation	2.6
Electrical Systems	8.0
Total	34.0 (30.0)

Table 11, Table 12, and Table 13 show the assumptions used in this COE analysis. The total capital requirement for the Destec HGCU case is $538,933,000 or $1346/kW, compared to $546,993,000 or $1365/kW for the Destec CGCU case. The levelized cost of electricity for the HGCU case in constant dollars is 40.4 mills/kWh, compared to 42.3 mills/kWh for the CGCU case.

Table 11. Capital Cost Assumptions

Engineering Fee	10% of PPC*
Project Contingency	15% of PPC
Construction Period	4 Yrs
Inflation Rate	3%
Discount Rate	11.2%
Prepaid Royalties	0.5% of PPC
Catalyst and Chemical Inventory	30 Dys
Spare Parts	0.5% of TPC**
Land	200 Acres @ $6,500/Acre
Start-Up Costs	
Plant Modifications	2% of TPI***
Operating Costs	30 Dys
Fuel Costs	7.5 Dys
Working Capital	
Coal	60 Dys
By-Product Inventory	30 Dys
O&M Costs	30 Dys

* PPC = Process Plant Cost
** TPC = Total Plant Cost
*** TPI = Total Plant Investment

Table 12. Operating & Maintenance Assumptions

<u>Consumable Material Prices</u>	
Illinois #6 Coal	$29.40/Ton
Raw Water	$0.19 /Ton
MDEA Solvent	$1.45/Lb
Claus Catalyst	$470/Ton
SCOT Activated Alumina	$0.067/Lb
Sorbent	$6,000/Ton
Nahcolite	$275/Ton
Off-Site Ash/Sorbent Disposal Costs	$8.00/Ton
Operating Royalties	1% of Fuel Cost
Operator Labor	$34.00/hour
Number of Shifts for Continuous Operation	4.2
Supervision and Clerical Labor	30% of O&M Labor
Maintenance Costs	2.2% of TPC
Insurance and Local Taxes	2% of TPC
Miscellaneous Operating Costs	10% of O&M Labor
Capacity Factor	85%

Table 13. Investment Factor Economic Assumptions

Annual Inflation Rate			3%
Real Escalation Rate (over inflation)			
O&M	0%		
Coal			-1.1%
Discount Rate			11.2%
Debt	80% of Total	9.0% Cost	7.2% Return
Preferred Stock	0% of Total	0.0% Cost	0% Return
Common Stock	20% of Total	20.0% Cost	<u>4.0% Return</u>
			11.2% Total
Book Life			20 Yrs
Tax Life			20 Yrs
State and Federal Tax Rate			38%
Investment Tax Credit			0%
Number of Years Levelized Cost			10 Yrs

Appendix A

Destec CGCU IGCC CASE 1 401 MW POWER PLANT

1st Q 1999 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$26,113
12	Oxygen Plant	0	$0	$48,492
12	Destec Gasifier	5	$3,051	$61,027
12	Recycle Gas Compressor	5	$132	$2,644
14	Low Temperature Gas Cooling	0	$0	$13,618
14	MDEA	0	$0	$5,158
14	Claus	0	$0	$9,863
14	SCOT	0	$0	$4,171
15	Gas Turbine System	5	$2,707	$54,136
15	HRSG/Steam Turbine	0	$0	$48,168
18	Water Systems	0	$0	$19,411
30	Civil/Structural/Architectural	0	$0	$25,152
40	Piping	0	$0	$19,411
50	Control/ Instrumentation	0	$0	$7,108
60	Electrical	0	$0	$21,871

Subtotal, Process Plant Cost		$366,342
Engineering Fees		$36,634
Process Contingency (Using cont. listed)	$5,890	
Project Contingency, 15 % Proc Plt & Gen Plt Fac		$54,951
Total Plant Cost (TPC)		$463,818
Plant Construction Period, 4.0 Years (1 or more)		
Construction Interest Rate, 11.2 %		
Adjustment for Interest and Inflation		$58,223
Total Plant Investment (TPI)		$522,041
Prepaid Royalties		$1,832
Initial Catalyst and Chemical Inventory		$69
Startup Costs		$12,772
Spare Parts		$2,319
Working Capital		$6,660
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$546,993
$/kW		1365

ANNUAL OPERATING COSTS – CASE 1

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,123	T/D	$29.40	/T	$28,482
Consumable Materials					
Water	2,924	T/D	$0.19	/T	$172
MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$181
Claus Catalyst	0.01	T/D	$470	/T	$1
SCOT Activated Alumina	15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst					$5
SCOT Chemicals					$16
Ash/Sorbent Disposal Costs	413	T/D	$8.00	/T	$1,024
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,561
Maintenance Costs	2.2%				$10,204
Royalties					$285
Other Operating Costs					$854
	Total Operating Costs				$48,245
By-Product Credits					
Sulfur	75.5	T/D	$75.00	/T	$1,757
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits				$1,757
	Net Operating Costs				$46,487

BASES AND ASSUMPTIONS – CASE 1

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	74550	T	$0.19	/T	$14
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alumina	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$69

Startup costs			
Plant modifications,	2	% TPI	$10,441
Operating costs			$1,643
Fuel			$689
		Total Startup Costs	$12,772
Working capital			
Fuel & Consumables inv	60	days supply	$5,578
By-Product inventory	30	days supply	$170
Direct expenses	30	days	$912
		Total Working Capital	$6,660

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY – CASE 1

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000
Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.8	27.2
Fuel Costs	10.4	9.1
Consumables	0.5	0.5
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	50.2	42.3

Destec HGCU IGCC CASE 2 400 MW POWER PLANT

1st Q 1999 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$25,057
12	Oxygen Plant	0	$0	$45,509
12	Destec Gasifier	5	$2,769	$55,376
12	Gas Compression (Recycle and Quench)	5	$267	$5,349
14	Gas Conditioning	10	$1,492	$14,918
14	Air Boost Compressor	0	$0	$859
14	Transport Desulfurizer	15	$1,287	$8,583
14	Sulfuric Acid Plant	0	$0	$18,066
15	Gas Turbine System	5	$2,705	$54,096
15	HRSG/Steam Turbine	0	$0	$47,986
18	Water Systems	0	$0	$14,066
30	Civil/Structural/Architectural	0	$0	$25,374
40	Piping	0	$0	$14,066
50	Control/ Instrumentation	0	$0	$7,171
60	Electrical	0	$0	$22,064

		Subtotal, Process Plant Cost	$358,539
Engineering Fees			$35,854
Process Contingency (Using cont. listed)			$8,520
Project Contingency,	15	% Proc Plt & Gen Plt Fac	$53,781
		Total Plant Cost (TPC)	$456,694
Plant Construction Period,	4.0	Years (1 or more)	
Construction Interest Rate,	11.2	%	
Adjustment for Interest and Inflation			$57,329
		Total Plant Investment (TPI)	$514,023
Prepaid Royalties			$1,793
Initial Catalyst and Chemical Inventory			$302
Startup Costs			$12,577
Spare Parts			$2,283
Working Capital			$6,655
Land,	200	Acres	$1,300
		Total Capital Requirement (TCR)	$538,933
		$/kW	1346

ANNUAL OPERATING COSTS – CASE 2

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	2,944	T/D	$29.40	/T	$26,850
Consumable Materials					
Water	2,102	T/D	$0.19	/T	$124
HGCU Sorbent	0.11	T/D	$6,000	/T	$197
Nahcolite	2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs	436	T/D	$8.00	/T	$1,082
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,542
Maintenance Costs	2.2%				$10,047
Royalties					$269
Other Operating Costs					$847
	Total Operating Costs				$46,610
By-Product Credits					
Sulfuric Acid	223.8	T/D	$68.00	/T	$4,722
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits				$4,722
	Net Operating Costs				$41,888

BASES AND ASSUMPTIONS – CASE 2

A. CAPITAL BASES AND DETAILS

		QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory						
Water		53594	T	$0.19	/T	$10
HGCU Sorbent		46	T	$6,000	/T	$276
Nahcolite		59	T	$275	/T	$16
	Total Catalyst and Chemical Inventory					$302
Startup costs						
Plant modifications,	2	% TPI				$10,280
Operating costs						$1,647
Fuel						$649
		Total Startup Costs				$12,577
Working capital						
Fuel & Consumables inv	60	days supply				$5,293
By-Product inventory	30	days supply				$457
Direct expenses	30	days				$905
		Total Working Capital				$6,655

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY – CASE 2

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000
Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.4	26.8
Fuel Costs	9.8	8.5
Consumables	0.6	0.5
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-1.8	-1.6
Total Cost of Electricity	48.0	40.4

Appendix B

Modifications made to 1998 IGCC Process System Study

Modifications made to the 1998 IGCC Process System Study

The attached summaries show the results obtained previously for the 1998 IGCC Process System Study and the results obtained based on the changes listed below to the economic analysis and the process simulations.

Economics

The following changes were made to the economic section of the 1998 System Study cases done by EG&G for the Gasification Technologies Product Team.

- The costs were brought to 1st Quarter 1999 dollars.
- The contingencies for several sections were changed to reflect advancements in technology development.
- The operating and maintenance costs were lowered to reflect recent technology improvements and competitive pressure (Annual Energy Outlook 2000).
  The number of operators was lowered.
  The maintenance costs were lowered. This is based on a percentage of the Total Plant cost.
- The cost for the Air Separation Units were updated to reflect recent price quotes from a supply vendor.
- The cost and attrition rate for the sorbent in the Hot Gas Cleanup cases were updated to reflect improvements in the state of the art sorbent development. The Separations and Gasification Engineering Division of NETL provided this information.
- The escalation rate of coal was updated to –1.1% from –0.9% and the price of coal was updated to $29.40/ton from $30.60/ ton per the Annual Energy Outlook 2000 projections.
- Some equipment costs were updated after viewing recent publications and talking to technical experts at NETL.

Process Simulations

The following changes were made to the process simulation section of the 1998 System Study done by EG&G for the Gasification Technologies Product Team.

- For Oxygen-blown gasifiers, the Air Separation Unit (ASU) uses an advanced cryogenic plant designed to take advantage of air being provided from a high pressure gas turbine. This resulted in the nitrogen and oxygen streams from the ASU being sent to boost compressors at higher pressures. This reduces power requirements for these compressors.

- Process Efficiencies for boost compressors and air compressors were based on industry recommended values. This resulted in isentropic stage efficiencies for air and nitrogen compressors of 83% compared with 85-87% being used in the 1998 study. Additionally, the oxygen boost compressor stage efficiency was set at 74% compared to 85% used previously. These modifications increased power requirements and partially eliminate the advantage (for oxygen-blown systems) of the above change.
- Simulation Codes are all available for use in ASPEN PLUS Version 10.1. (Some of the 1998 cases were in version 9.3).
- The databank for pure component information was changed to “Pure10” which is ASPEN PLUS latest release. Only minor changes in some stream information resulted from this change.
- The ASPEN representation for boost compressors and the air compressor was changed from a series of compressor + intercoolers (ASPEN Blocks “COMPR” and “HEATX”) to a multi-stage intercooled compressor (ASPEN Block “MCOMPR”). The low quality heat available from intercoolers was not used in the steam cycle. This had a minimal effect since most cases have excess low quality heat available.

FY 2000 IGCC Systems Summary Update

* (Contingencies on Hot Gas Cleanup Sections: Gas Conditioning 15/10%, Transport Desulfurizer 15%, Sulfator 15%)

	Texaco Quench	Texaco Radiant + Convective		Shell		Destec		British Gas/ Lurgi	
	CGCU CASE 1	CGCU CASE 2	HGCU CASE 3	CGCU CASE 1	HGCU CASE 2	CGCU CASE 1	HGCU CASE 2	CGCU CASE 1	HGCU CASE 2
Gas Turbine Power (MWe)	272.7	272.4	272.1	272.3	272.5	272.8	272.6	272.6	272.5
Steam Turbine Power (MWe)	152.3	191.7	183.8	188.9	187.6	172.2	171.1	133.4	130.3
Misc. /Aux. Power (MWe)	42.0	51.3	46.3	48.3	47.8	44.4	43.3	31.1	30.7
Total Plant Power (MWe)	382.9	412.8	409.6	412.8	412.4	400.6	400.4	374.9	372.1
Efficiency, HHV (%)	39.7	43.5	46.5	45.7	48.0	45.0	47.6	45.3	49.4
Efficiency, LHV (%)	41.2	45.1	48.3	47.4	49.8	46.7	49.4	47.0	51.3
Total Cap Requirement ($1000)	$500,599	$594,053	$561,229	$566,101	$564,963	$546,993	$538,933	$533,664	$503,640
$/kW	$1,307	$1,439	$1,370	$1,371	$1,370	$1,365	$1,346	$1,423	$1,354
Net Operating Costs ($1000)	$48,411	$49,422	$43,426	$46,969	$42,562	$46,487	$41,888	$46,445	$40,416
COE (mills/kW-H)	42.5	44.3	41.1	42.1	40.7	42.3	40.4	44.5	41.1

	KRW Air-Blown With	/out In-Bed Sulf Captur		KRW Oxygen Blown		Transport Air-Blown		Transport Oxygen-Blown	
	HGCU CASE 1	CGCU CASE 2	HGCU CASE 3	CGCU	HGCU	CGCU	HGCU CASE 1	CGCU	HGCU CASE 2
Gas Turbine Power (MWe)	272.6	272.4	272.8				272.8		272.6
Steam Turbine Power (MWe)	184.8	177.0	174.3				162.6		142.4
Misc. /Aux. Power (MWe)	24.5	25.3	25.5				20.0		31.3
Total Plant Power (MWe)	432.9	424.1	421.6				415.4		383.7
Efficiency, HHV (%)	48.4	44.3	46.3				49.8		47.1
Efficiency, LHV (%)	50.2	45.9	48.0				51.7		48.8
Total Cap Requirement (x1000)	$566,641	$544,961	$550,305				$484,062		$496,722
$/kW	$1,309	$1,285	$1,305				$1,165		$1,295
Net Operating Costs (x1000)	$54,059	$48,032	$43,740				$45,388		$47,294
COE (mills/kW-H)	42.4	40.3	39.5				38.1		41.9

FY 1998 IGCC Systems Summary

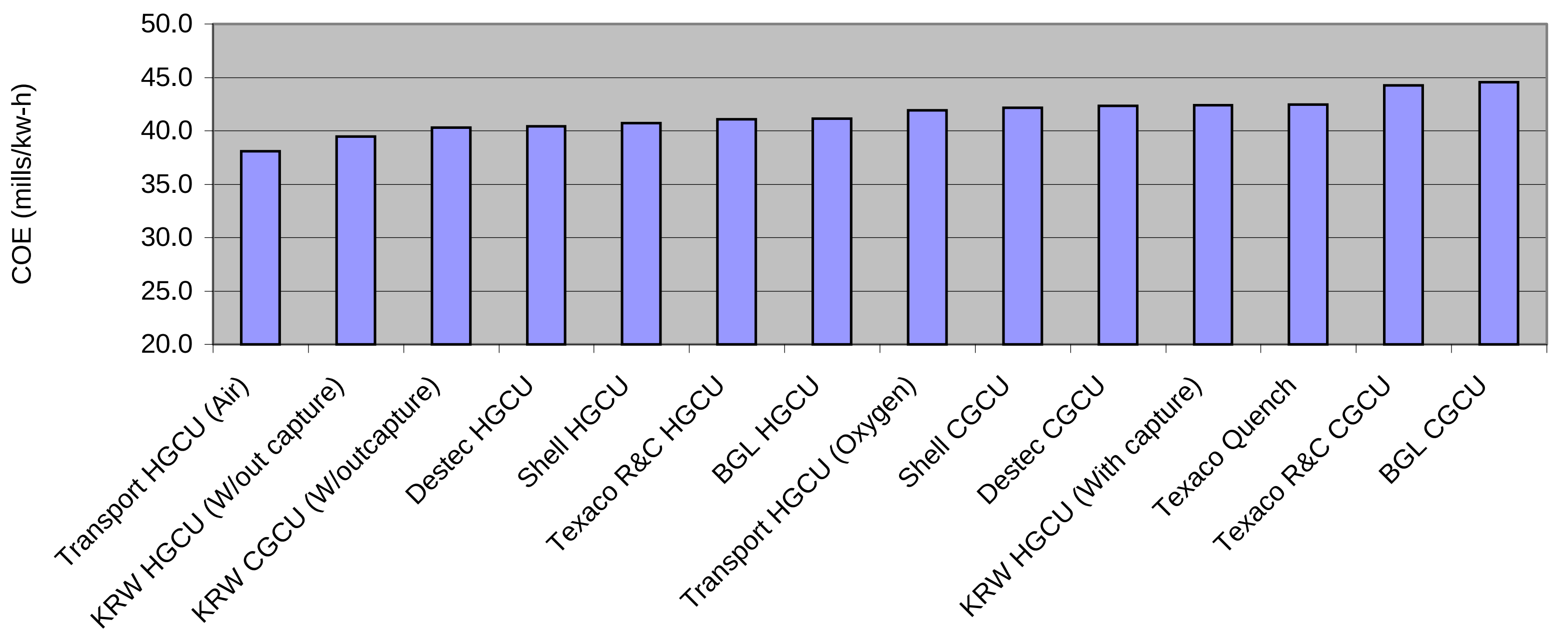
	Texaco	Texaco		Shell		Destec		British Gas/	
	Quench	Radiant +	Convective					Lurgi	
	CGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3	CASE 1	CASE 2	CASE 1	CASE 2	CASE 1	CASE 2
Gas Turbine Power (MWe)	271.9	272.5	271.2	273.0	271.6	273.0	271.1	272.4	272.1
Steam Turbine Power (MWe)	154.1	192.4	184.9	188.3	189.2	173.5	172.0	131.2	130.7
Misc./Aux. Power (MWe)	44.4	54.5	49.2	54.3	53.1	48.1	46.3	34.0	33.4
Total Plant Power (MWe)	381.7	410.4	406.9	407.1	407.7	398.5	396.9	369.5	369.3
Efficiency, HHV (%)	39.6	43.4	46.3	45.4	47.5	44.8	47.4	45.4	49.1
Efficiency, LHV (%)	41.1	45.0	48.1	47.0	49.3	46.5	49.1	47.1	50.9
Total Cap Requirement ($1000)	519,625	596,034	593,781	596,811	588,502	551,179	552,513	559,717	528,069
$/KW	1,361	1,452	1,459	1,466	1,443	1,383	1,392	1,515	1,430
Net Operating Costs ($1000)	67,128	69,832	70,836	67,876	69,445	65,711	67,279	65,889	64,710
COE (mills/KW-H)	47.2	48.1	48.8	47.9	48.0	46.2	47.0	50.3	48.5

	KRW Air-Blown			KRW		Transport		Transport	
	With	/out In-Bed Sulf Captur		Oxygen Blown		Air-Blown		Oxygen-Blown	
	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU	CGCU	HGCU
	CASE 1	CASE 2	CASE 3				CASE 1		CASE 2
Gas Turbine Power (MWe)	271.8	271.7	272.9				271.4		272.1
Steam Turbine Power (MWe)	181.0	172.7	170.8				160.1		141.9
Misc./Aux. Power (MWe)	23.8	24.5	24.7				19.5		32.7
Total Plant Power (MWe)	429.0	419.9	419.1				412.0		381.3
Efficiency, HHV (%)	48.4	44.2	46.3				49.9		46.9
Efficiency, LHV (%)	50.2	45.8	48.0				51.7		48.7
Total Cap Requirement ($1000)	607,771	582,832	601,760				520,051		538,369
$/KW	1,417	1,388	1,436				1,262		1,412
Net Operating Costs ($1000)	75,562	68,706	71,722				64,417		67,551
COE (mills/KW-H)	48.3	46.1	48.0				43.6		48.4

COE Summary IGCC Systems Study 2000 Update	
Transport HGCU (Air)	38.1
KRW HGCU (W/out capture)	39.5
KRW CGCU (W/outcapture)	40.3
Destec HGCU	40.4
Shell HGCU	40.7
Texaco R&C HGCU	41.1
BGL HGCU	41.1
Transport HGCU (Oxygen)	41.9
Shell CGCU	42.1
Destec CGCU	42.3
KRW HGCU (With capture)	42.4
Texaco Quench	42.5
Texaco R&C CGCU	44.3
BGL CGCU	44.5

COE Summary IGCC Systems Study 1998	
Transport HGCU (Air)	43.6
KRW CGCU (W/outcapture)	46.1
Destec CGCU	46.2
Destec HGCU	47.0
Texaco Quench	47.2
Shell CGCU	47.9
KRW HGCU (W/out capture)	48.0
Shell HGCU	48.0
Texaco R&C CGCU	48.1
KRW HGCU (With capture)	48.3
Transport HGCU (Oxygen)	48.4
BGL HGCU	48.5
Texaco R&C HGCU	48.8
BGL CGCU	50.3

IGCC Base Case COE Comparison



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