Comparison of Pratt and Whitney Rocketdyne IGCC and Commercial IGCC Performance

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Final Report

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Disclaimer

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LIST OF ACRONYMS AND ABBREVIATIONS

acfm	Actual cubic feet per minute
AGR	Acid Gas Removal
ASU	Air Separation Unit
BACT/RACT	Best/Reasonably available control technology
CFR	Code of Federal Regulations
COS	Carbonyl Sulfide
DCS	Distributed Control System
DOE	Department of Energy
EPRI	Electric Power Research Institute
ERC	Emission Reduction Credits
FGD	Flue gas desulfurization
GEE	General Electric Energy
HHV	Higher heating value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasifier Combined Cycle
kWe	Kilowatt Electrical
kWh	Kilowatt hour
kWt	Kilowatt Thermal
LAER	Lowest achievable emission rate
LCOE	Levelized Cost of Electricity
lb/hr	pound per hour
LHV	Lower heating value
LNB	Low NOx Burner
LP	Low Pressure
MDEA	Methyldiethanolamine
MMBtu	Million British thermal unit
MMlb	Million pounds
MWe	Megawatt Electrical
MWh	Megawatt hour
MWt	Megawatt Thermal
NGCC	Natural gas combined cycle
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
ppmvd	Parts per million volume, dry
PRB	Powder River Basin
psia	Pounds per square inch absolute
PWR	Pratt & Whitney Rocketdyne
SCR	Selective catalytic reduction
SOx	Oxides of sulfur
TGTU	Tail gas treating unit
TPC	Total Plant Cost
tpd	tons per day
WGS	Water Gas Shift

EXECUTIVE SUMMARY

This report compares the performance and cost of commercial Integrated Gasification Combined Cycle (IGCC) plants using General Electric Energy (GEE) and Shell gasifiers with conceptual IGCC plant designs using the Pratt & Whitney Rocketdyne (PWR) compact gasifier. The PWR gasifier is also compared with the GEE gasifier in hydrogen production and carbon capture mode. With the exception of the PWR gasifier, the plants are designed with commercially available equipment to be operational in approximately 2010. All results should be considered preliminary and dictated in large part by the selected design basis. Exhibit 1 lists the basic design configuration for each case included in this topical report.

Exhibit 1
Plant Configuration Summary

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	H_2S Separation/ Removal
1	IGCC	1800/1050/1050	2 x GE 7FB	PWR Radiant Quench	Selexol
2	IGCC	1800/1050/1050	2 x GE 7FB	GE Energy Radiant Quench	Selexol
3	IGCC	1800/1050/1050	2 x GE 7FB	PWR Convective	Sulfinol
4	IGCC	1800/1050/1050	2 x GE 7FB	Shell Convective	Sulfinol
5	H_2	1200/1000	None	PWR	Selexol
6	H_2	1200/1000	None	GE Energy	Selexol

Note: All gasifiers use 95 mol% O_2 as an oxidant and a Claus Plant for Sulfur Recovery

The Total Plant Cost and corresponding Levelized Cost of Electricity (LCOE) for each case have been evaluated at three levels of total plant availability, or capacity factors – 85%, 90% and 94%. For the commercial IGCC plants (based on GEE and Shell gasifiers), the most optimistic projections yield 85% capacity factor when excluding a spare gasification train in the design and 90% when including the spare. Based on PWR claims, a 94% capacity factor was assumed for systems without a spare gasifier train. While it is not expected that the GEE and Shell cases will achieve a 94% capacity factor with a single spare gasification train, these case were evaluated at a 94% CF only for purposes of economic comparison to the PWR case.

The performance results for each case are summarized in Exhibit 2. It is important to note that results for the PWR gasifier are projections. The PWR gasifier has not been demonstrated at commercial-scale, while the GEE and Shell gasifiers have widespread commercial operating experience.

Cases 1 and 2 compare the PWR gasifier with the GEE gasifier, both in Radiant Quench heat recovery mode, using a similar design basis. Gross steam turbine power output for the GEE gasifier is 52 MW higher than the PWR gasifier; however, this advantage is partially offset by a 22 MW higher auxiliary load requirement for the GEE gasifier and a 13% lower thermal input for the PWR case. The overall results indicate a 3 percentage point net plant efficiency (HHV) improvement of the PWR IGCC over the GEE IGCC. In addition to the efficiency improvement, Case 1 costs nearly $134 million less ($147/kWe) and shows an 8% reduction in the levelized cost of electricity on a common capacity factor. If one compared each plant at its maximum projected capacity factor without a spare gasification train (85% for GEE and 94% for PWR), the reduction in cost of electricity is nearly 15%.

Exhibit 2
Performance Summary and Economic Analysis Results

	Case 1 PWR Radiant Quench	**Case 2** GE Energy Radiant Quench	**Case 3** PWR Convective	**Case 4** Shell Convective	**Case 5** PWR H_2 Plant	**Case 6** GE Energy H_2 Plant
Performance						
Gas Turbine Power, MW_e	464.0	464.0	464.0	464.0	None	None
Sweet Gas Expander, MW_e	11.8	11.9	10.9	None	None	None
Steam Turbine Power, MW_e	230.7	282.2	239.9	270.4	85.9	75.0
Gross Power Output, MW_e	706.5	758.1	714.8	734.4	85.9	75.0
Auxiliary Power Load, MW_e	101.3	123.2	101.1	109.8	116.5	124.8
Net Power Output, MW_e	605.2	634.8	613.7	624.6	(30.6)	(49.8)
Net Plant Efficiency (HHV)	42.2%	39.2%	42.9%	42.0%	68.1%	59.4%
Net Plant Heat Rate, Btu/kWh HHV	8,078	8,699	7,957	8,130	N/A	N/A
Thermal Input, MW_t	1,433	1,619	1,431	1,488	1,433	1,433
Consumables/Products						
Coal Feed Flowrate, lb/hr	419,045	473,379	418,574	435,161	419,050	419,050
Gasifier Oxidant (95% O_2), lb/hr	294,706	396,246	294,374	337,137	294,709	350,770
Hydrogen Product, lb/hr	None	None	None	None	56,179	50,322
Sulfur Product, lb/hr	10,452	11,839	10,414	10,891	10,478	10,462
Economics						
85% Capacity Factor						
Total Plant Cost, \$x1000	838,323	972,345	743,294	948,732	471,950	555,461
Total Plant Cost, \$/kW	1,385	1,532	1,211	1,519	N/A	N/A
LCOE, mills/kWh	48.9	53.4	44.6	52.8	\$0.85/kg	\$1.10/kg
90% Capacity Factor						
Total Plant Cost, \$x1000	838,323	1,057,235	743,294	1,045,428	471,950	592,858
Total Plant Cost, \$/kW	1,385	1,665	1,211	1,674	N/A	N/A
LCOE, mills/kWh	46.9	54.3	42.8	54.2	\$0.82/kg	\$1.10/kg
94% Capacity Factor						
Total Plant Cost, \$x1000	838,323	1,057,235	743,294	1,045,428	471,950	592,858
Total Plant Cost, \$/kW	1,385	1,665	1,211	1,674	N/A	N/A
LCOE, mills/kWh	45.4	52.5	41.5	52.5	\$0.80/kg	\$1.07/kg

A – Total Plant Costs for Cases 2, 4 and 6 at 90% and 94% CF in this table include spare gasification trains
B – LCOE is Levelized Cost of Electricity. Costs for a spare gasifier were added to Cases 2 and 4 for 94% CF data.
C – Case 5 & 6 show Total Plant Cost of Hydrogen in \$/kg of H_2/day and Levelized Cost of Hydrogen in \$/kg H_2.

Cases 3 and 4 were designed to compare the PWR Gasifier with the Shell Gasifier, both in syngas quench/convective syngas cooler heat recovery mode, using a similar design basis. Gross steam turbine power output for the Shell Gasifier is 30 MW higher than the PWR Gasifier; however, this advantage is partially offset by a 9 MW higher auxiliary load requirement for the Shell Gasifier and a 4% lower thermal input for the PWR case. The result is a nominal 1 percentage point net plant efficiency (HHV) gain for the PWR IGCC over the Shell IGCC. In addition, there is a projected $206 million ($308/kWe) reduction in total plant cost for the PWR plant. This is primarily attributable to incorporating a less expensive gasifier and syngas cooling system in addition to a reduction in coal handling, preparation and feed costs associated with using a proprietary dry coal feed pump, currently under development at PWR, instead of a conventional lock hopper system. The PWR process shows a 15% and 20% reduction in the levelized cost of electricity for a capacity factor of 85% and 94%, respectively.

Cases 5 and 6 were designed to compare the PWR Gasifier with the GE Energy Gasifier, both in hydrogen production with ~90% carbon capture mode, using a similar design basis. With each design processing 419,050 lb/hr of coal, the overall hydrogen production rate for the GE Energy gasifier is 50,322 lb/hr hydrogen, while the hydrogen production rate for the PWR gasifier is 56,179 lb/hr. Another disadvantage in the GEE design is that it requires 50 MWe input in order to operate at the stated production, while the PWR design requires only 31 MWe for its respective hydrogen production. Power requirements for both cases include the supplemental power generation of each plant. Case 5 costs more than $83 million less and shows a 23% reduction in the levelized cost of hydrogen on a common capacity factor.

PWR gasifier performance predictions are based on a proprietary one-dimensional kinetic model validated with experimental data from earlier PWR work with coal-fired systems in the areas of hydrogasification-liquefaction, steam/oxygen gasification, magnetohydrodynamic (MHD) power, acetylene production, and low NOx/SOx combustion.[1,2,3,4] Carbon conversion predictions from the one-dimensional kinetic model have been anchored to a limited amount of experimental kinetics data. Future pilot plant gasifier tests will provide a means to vary process parameters (reactant flow rates and conditions, reactor length, residence times, and pressures) and monitor results (carbon conversion, syngas composition, and heat losses) to further validate model kinetics.

Performance results for the PWR gasifier were based on methodology provided to RDS by PWR for the NASA code, “Chemical Equilibrium for Analysis”. Details are provided in the following sections of this report. Non-idealities that can occur in either pilot scale or commercial scale reactors are not accounted for by this method, which assumes 100% carbon conversion based on ideal mixing, even temperature distribution and a high coal particle heat rate. These assumptions must be verified in pilot and commercial scale demonstrations before one can conclude that the performance of the PWR Gasifier is an improvement over either GE or Shell, whose gasifiers have been widely demonstrated commercially.

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1 DESIGN BASIS

Six plant designs have been prepared for this comparison. The three PWR cases are compared with similar corresponding GE Energy gasifier and Shell gasifier cases. Exhibit 3 lists the basic process configuration for each case.

Exhibit 3
Plant Configuration Summary

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	H_2S Separation/ Removal
1	IGCC	1800/1050/1050	2 x GE 7FB	PWR Radiant Quench	Selexol
2	IGCC	1800/1050/1050	2 x GE 7FB	GE Energy Radiant Quench	Selexol
3	IGCC	1800/1050/1050	2 x GE 7FB	PWR Convective	Sulfinol
4	IGCC	1800/1050/1050	2 x GE 7FB	Shell Convective	Sulfinol
5	H_2	1200/1000	None	PWR	Selexol
6	H_2	1200/1000	None	GE Energy	Selexol

Note: All gasifiers use 95 mol% O_2 as an oxidant and a Claus Plant for Sulfur Recovery

The high pressure operation of both the GE Energy and PWR gasifiers favors the use of a physical solvent for acid gas removal; therefore, Selexol has been chosen for this service in Cases 1, 2, 5 and 6. Sulfinol (a hybrid chemical/physical solvent commonly used in conjunction with the Shell dry feed gasifier) was used to compare PWR with Shell in Cases 3 and 4.

1.1 Site Characteristics

The plants in this study are assumed to be located in the mid-west United States. Ambient conditions and site characteristics are shown in Exhibit 4 and Exhibit 5.

All cases in this study are modeled with Illinois #6 coal. The coal characteristics are listed in Exhibit 6.

Exhibit 4
Site Ambient Conditions

Elevation, ft	0
Barometric Pressure, psia	14.696
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Exhibit 5
Site Characteristics

Location	Green-field, Midwestern USA
Topography	Level
Size, acres	300
Transportation	Rail
Ash Disposal	Off Site
Water	Municipal
Access	Land locked, also having access by train and highway

Exhibit 6
Design Coal Characteristics

Rank	**Bituminous**	
Seam	**Illinois #6 (Herrin)**	
Source	**Old Ben mine [5]**	
Proximate Analysis (weight %) (Note A)		
	As-Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, Btu/lb	11,666	13,126
LHV, Btu/lb	11,252	12,712
	As-Received	**Dry**
Moisture	11.12	0.00
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 (Note B)	6.88	7.75
Total	100.00	100.00

Notes: A. The proximate analysis assumes sulfur as a Volatile matter.
B. By Difference

1.2 Environmental Constraints

The following regulatory assumptions are used in the design basis for assessing environmental control technologies:

- EPA Clear Air Mercury Rule (CAMR) requirement will be used for mercury.
- BACT Determination emission limits will be used for particulates, sulfur dioxide, nitrogen oxides and carbon monoxide.

- NOx Emission Reduction Credits (ERCs) and allowances are not available for the project emission requirements.
- Solid waste disposal is either offsite at a fixed $/ton fee or is classified as a byproduct for reuse, claiming no net revenue ($/ton) or cost.
- Raw water is available to meet technology needs.
- Wastewater discharge will meet effluent guidelines rather than water quality standards for this screening.

The environmental approach for the study is to evaluate each case on the same regulatory design basis, considering differences in fuel and technology. The current enacted process for establishing environmental requirements for new plants is the EPA's New Source Performance Standards (NSPS) [6]. Since all cases are located at a green-field site, NSPS could be a starting point for design air emission rates. NSPS emission requirements are summarized in Exhibit 7.

Exhibit 7
NSPS Emission Requirements Summary

Pollutant	Emission Limit After 2008
Particulate Matter (PM),	0.03 lb/10^6 Btu and 99% reduction for solid
Sulfur Dioxide (SO_2)	1.2 lb/MMBtu and at least 90% reduction, or sliding scale down to a minimum 70% reduction when emissions are 0.6 lb/MMBtu or less
Nitrogen Oxides (NOx)	0.15 lb/MMBtu (1.6 lb/MWh)
Opacity	Less then 20% (6 minute average, except for one 6-minute period per hour of not more than 27%)

Note: Dry flue gas, 6% O_2

However, permitting a new plant with emission rates controlled by NSPS requirements likely will not be acceptable to the EPA and/or individual states, who would probably invoke The New Source Review (NSR) permitting process. The NSR process is expected to result in allowable emission rates more stringent than NSPS. The NSR process requires installation of emission control technology meeting either Best Available Control Technology (BACT) determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on EPA Green Book Non-attainment Area Map [7] relatively few areas in the Midwestern US are classified as "non-attainment"; therefore, for the purposes of this study, the site is assumed to be in an attainment area. Representative BACT emission limits and technology to meet them are provided in Exhibit 8.

Exhibit 8
Best Available Control Technology Determinations by Technology

Process	Pollutants	Emissions Limitation	Type of Technology
PC Boiler	PM/PM-10	0.012 – 0.015 lb/10^6 Btu	Fabric Filter or ESP
	Sulfur Dioxide	0.06 – 0.2 lb/10^6 Btu	Low-Sulfur Fuel, FGD
	Nitrogen Oxides	0.07 – 0.15 lb/10^6 Btu	SCR
	Carbon Monoxide	0.10 – 0.15 lb/10^6 Btu	Combustion Controls
IGCC	PM/PM-10	0.013 lb/10^6 Btu	Syngas water scrubber
	Sulfur Dioxide	0.17 lb/10^6 Btu	AGR
	Nitrogen Oxides	15 ppmvd @15% O_2	Nitrogen or steam diluent injection, Combustion controls
	Carbon Monoxide	25 ppmvd @15% O_2	Combustion Controls
NGCC	PM/PM-10	0.01 – 0.013 lb/10^6 Btu	Combustion Controls
	Sulfur Dioxide	0.04 – 0.17 lb/10^6 Btu	Low-Sulfur Fuel
	Nitrogen Oxides	2.5 – 25 ppmvd @ 15% O_2	LNB, SCR
	Carbon Monoxide	3 – 20 ppmvd @ 15% O_2	Combustion Controls

Note: IGCC data is based on Tampa Electric Company TECO-Polk BACT determination [8]

2 CASE 1 - PWR GASIFIER BASED IGCC PLANT DESCRIPTION AND RESULTS

Case 1 produces 605 MWe at 42.2% efficiency (8,078 BTU/kWh heat rate). The plant costs $838MM and, at 85% CF, provides electricity at 48.9 mills/kWh.

A block flow diagram and associated stream tables for the Case 1 PWR gasifier-based IGCC plant in radiant quench heat recovery mode are presented in Exhibit 9 and Exhibit 10, respectively. Performance, capital costs and operating costs are presented in Exhibit 11 through Exhibit 14.

2.1 Process Description

The Case 1 PWR IGCC plant consists of two compact, radiant-cooled gasifiers each fed with approximately 1,800 tpd of 95% oxygen produced from an on site Air Separation Unit (ASU) and approximately 2,500 tpd of Illinois #6 coal dried from 11.12% to 5% in a syngas/HRSG gas-fired coal dryer. It is assumed that Illinois #6 coal has 5% inherent moisture.

A proprietary PWR coal extrusion feed system is utilized for feeding dried coal to the PWR gasifier. Each gasifier train in the PWR process requires approximately 130 tpd of nitrogen from the Air Separation Unit as coal transport gas as well as approximately 390 tpd of steam injection.

The PWR process claims an adiabatic flame temperature of ~2600°F, 1,000 psig operating pressure, and 100% carbon conversion. Approximately 490 tpd of slag (100% ash) is removed from the gasification reaction products as hot syngas and molten solids from the reactor flow downward into a radiant cooler where the syngas is cooled and the ash solidifies. Raw syngas continues downward into a quench system and then into a syngas scrubber for removal of entrained solids. Since the syngas temperature exiting the quench is too low for COS hydrolysis to efficiently occur, the syngas is heated to 400°F before entering a hydrolysis reactor, where >99% of the carbonyl sulfide is converted to hydrogen sulfide. The gas is then cooled to ~100°F and cleaned of ammonia and mercury prior to feeding the gas to the acid gas removal system.

A single stage Selexol AGR process separates the syngas into an acid gas stream containing hydrogen sulfide and carbon dioxide, and into a sweet gas stream containing the fuel gas to be combusted in the gas turbine. The acid gas stream is sent to a two bed Claus sulfur recovery plant with a tail gas clean up unit. Using approximately 130 tpd of 95% oxygen, the Claus process catalytically converts the gaseous sulfur compounds into elemental sulfur for collection and sale. A hydrogenation reactor converts the remaining gaseous sulfur dioxide into hydrogen sulfide, which may be separated from the tail gas in an MDEA tail gas treating unit. H_2S is then recycled back to the Claus plant thermal reaction zone to improve overall sulfur recovery.

The clean synthesis gas stream exits the Selexol unit at approximately 125°F, where it is humidified with hot water at 380°F. The humidifier accomplishes some reheating of the syngas while partially diluting the gas for NOx mitigation in the gas turbine combustors. After sulfur removal, the sweet fuel gas is also depressurized through an expander from 695 psia to 380 psia to generate ~12 MW_e of power.

Further reheating of the syngas, to 535°F, improves the gas turbine heat rate by reducing the amount of combustion energy used for heating the gas. In order to minimize NOx formation, the synthesis gas must be diluted to ~120 Btu/scf (LHV basis). Approximately 11,000 tpd of nitrogen diluent and 1,700 tpd of steam are added to accomplish the dilution. The resultant fuel gas stream is combined with compressed and heated ambient air and then combusted in two parallel General Electric 7FB model turbines.

The combustion products exiting the gas turbines are fed to a HRSG for heat recovery and additional power production before discharge to the atmosphere.

2.2 Modeling Assumptions for PWR Gasifier

PWR has made the following assumptions about their gasifier performance in the absence of substantial pilot data. These assumptions were used in the RDS analysis:

1. 100% carbon conversion based on expectations of the multi-injection port nozzle and high coal particle heat rate.
2. Fuel-bound atomic species exist in their elemental state for the purposes of the Gibbs Free Energy minimization calculations.
3. Unrestricted Gibbs Free Energy Minimization calculations for most governing gasification reactions due to the prototype reactor design features, which support assumptions of ideality: high coal particle heat rate, uniform coal distribution and 100% carbon conversion.
4. 80% of fuel-bound nitrogen is converted to ammonia. Gibbs Free Energy Minimization calculations for the ammonia-forming gasification reaction was manipulated to achieve this vendor-specified value.

RDS assessment of the five main modeling assumptions used in the study is:

1. The multi-port injection nozzle theoretically will promote improved mixing and gasification, which may result in an improved coal particle heat rate and an even temperature distribution. However, this assumption is optimistic and will have to be proven in actual demonstrations. The performance estimates made on this assumption must be considered a “best case scenario”.
2. This is a common assumption made in systems analyses that produces reasonable results.
3. Unrestricted Gibbs Free Energy Minimization generally does not produce results that match actual performance for current commercial systems. Non-idealities that occur in either pilot scale or commercial scale reactors are not accounted for in this method. The efficiency of the gasifier, as a result, must be considered an upper-limit “best case scenario”. Sensitivity studies will be required to determine the impact of incorporating these non-idealities on a case to case basis.
4. RDS has found few instances where near 80% of fuel-bound nitrogen is converted to ammonia. According to results published in the EPRI Coal Gasification Guidebook [9], 10-20% seems to be a reasonable assumption. With all other things equal, the increase in available hydrogen in the case converting 10% of fuel-bound N_2 over the case converting 80% of fuel-bound N_2, can result in an absolute increase in gasifier overall cold gas efficiency (including ammonia and sulfur species) of up to 0.35%.

Background Information Provided by PWR

PWR provided the following text to describe the history and source of their gasifier performance projections:

> PWR advanced gasifier performance predictions are based on a proprietary one-dimensional kinetic model validated with experimental data from earlier PWR work with coal-fired systems in the areas of hydrogasification-liquefaction, steam/oxygen gasification, magnetohydrodynamic (MHD) power, acetylene production, and low NOx/SOx combustion. [1, 2]
>
> The kinetic model describes entrained flow gasifier reactor dynamics in terms of the following physical and chemical phenomena:
>
> (1) Particle boundary layer transport
>
> (2) Conservation equations of the bulk flow
>
> (3) Chemical reactions of the freestream
>
> (4) Thermochemical and freestream transport properties
>
> (5) Convective and radiative heat transfer between the gasifier walls and internal process stream.
>
> (6) Detailed coal devolatilization kinetics, heterogeneous oxidation/gasification kinetics, and mass transport within the pore structure of the particles. This PWR proprietary coal particle sub-model is fundamentally as detailed as the recent published work by Niksa et al. [4].
>
> Reactant mixing was demonstrated to occur at the point where the impinging coal and steam/oxygen streams meet in previous work at PWR [3]. This allows modeling of the entrained flow gasifier on the basis of uniformly mixed reactants across the reactor cross section.
>
> The kinetic model uses freestream gas equilibrium in those regions where the gas temperatures are high (usually above 2,000°F) and the kinetics are extremely fast. Otherwise homogeneous gas phase kinetics is incorporated. All kinetic and equilibrium calculations are based on localized conditions within the freestream gas or coal particle.
>
> In addition to the one-dimensional kinetic model, PWR also uses a chemical equilibrium computer code -- based upon the NASA code, "Chemical Equilibrium for Analysis" – as an initial first cut approximation for slagging entrained flow coal gasifiers. These chemical equilibrium results are modified to reflect past experience that NH_3 content is considerably higher than equilibrium predictions. Based on hydrogasification experimental and one-dimensional kinetic model results, it is assumed that 80% of the fuel-bound nitrogen is converted to ammonia and does not equilibrate with the free-stream gas. The PWR equilibrium model is also capable of including heat loss estimates through the gasifier walls.
>
> For the first cut slagging gasifier equilibrium approximation, the gasifier product gas is based on the freestream chemical equilibrium calculated at the exit point. Unconverted carbon (due to kinetic constraints) is treated as an inert for the purpose of equilibrium calculations, as it is throughout the reactor. The amount of unconverted carbon and reactor

heat losses can be provided from either actual experimental results or the one-dimensional kinetic model described above.

Carbon conversion predictions from the one-dimensional kinetic model have been anchored to a limited amount of experimental kinetics data. The pilot plant gasifier will provide a means to vary process parameters (reactant flow rates and conditions, reactor length, residence times, and pressures) and monitor results (carbon conversion, syngas composition, heat losses) to continue validating model kinetics. Though the carbon conversion in actual operation will be limited by design and operating constraints, it was assumed in this study that 100% carbon conversion is achieved.

Exhibit 9
Case 1 - PWR IGCC Plant Block Flow Diagram

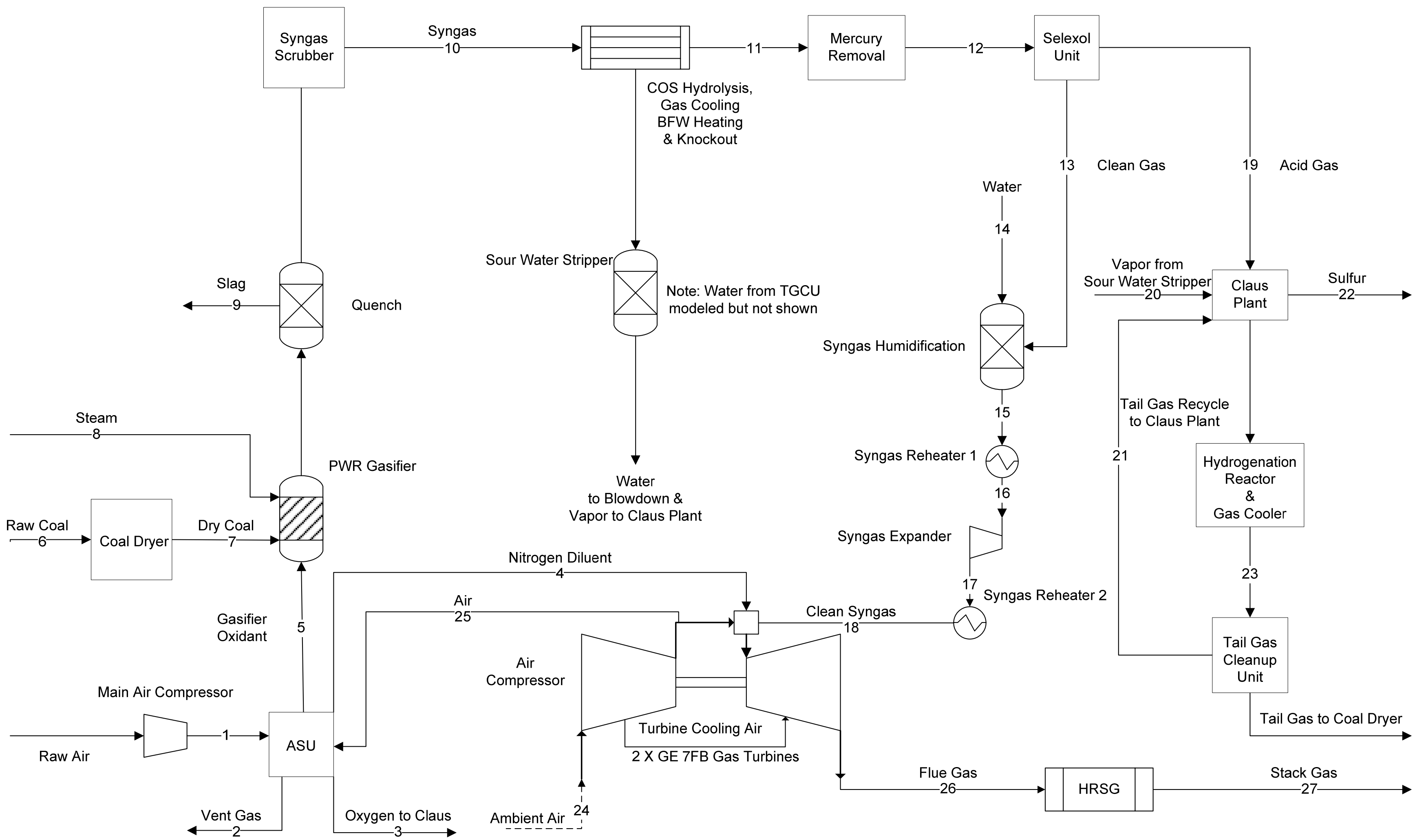

Exhibit 10
Case 1 - PWR IGCC Plant Stream Table

	1	2	3	4	5	6[A]	7[A]	8	9	13	14	15
V-L Mole Fraction												
Ar	0.0094	0.0594	0.0322	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0000	0.0015
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6082	0.0000	0.4737
CO_2	0.0003	0.0138	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0173	0.0000	0.0135
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3386	0.0000	0.2638
H_2O	0.0104	0.4392	0.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.2211
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.4876	0.0178	1.0000	0.0500	0.0000	0.0000	0.0000	0.0000	0.0340	0.0000	0.0265
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	31,027	1,030	340	32,103	9,268	2,612	1,112	3,591	0	35,264	10,028	45,275
V-L Flowrate (lb/hr)	895,275	25,288	10,944	899,325	294,706	47,017	20,021	64,695	0	686,321	180,511	866,680
Solids Flowrate (lb/hr)	0	0	0	0	0	372,027	372,027	0	40,634	0	0	0
Temperature (°F)	271	70	90	450	800	59	195	800	385	124	380	359
Pressure (psia)	225.0	16.4	56.4	375.0	1,191.2	14.7	1,200.0	1,200.0	930.0	768.0	755.0	700.0
Density (lb/ft^3)	0.83	0.12	0.308	1.08	2.76	--	--	1.60	--	2.39	50.61	1.54
Molecular Weight	28.85	24.55	32.18	28.01	31.80	--	--	18.02	--	19.46	18.02	19.14

A - Solids flowrate includes coal; V-L flowrate includes water from coal (11.12 wt% moisture)
Note: Streams containing proprietary data are excluded from these stream tables.

Exhibit 10 (continued)
Case 1 - PWR IGCC Plant Stream Table

	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0094	0.0094	0.0094	0.0071	0.0071
CH_4	0.0015	0.0015	0.0015	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.4737	0.4737	0.4737	0.0320	0.0081	0.0000	0.0000	0.0012	0.0000	0.0000	0.0000	0.0000
CO_2	0.0135	0.0135	0.0135	0.1360	0.0041	0.4972	0.0000	0.1164	0.0003	0.0003	0.0796	0.0796
COS	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2638	0.2638	0.2638	0.0178	0.0016	0.0004	0.0000	0.0879	0.0000	0.0000	0.0000	0.0000
H_2O	0.2211	0.2211	0.2211	0.0518	0.0000	0.0764	0.0000	0.5093	0.0104	0.0104	0.1151	0.1151
H_2S	0.0000	0.0000	0.0000	0.4819	0.0132	0.4254	0.0000	0.0253	0.0000	0.0000	0.0000	0.0000
N_2	0.0265	0.0265	0.0265	0.2804	0.0005	0.0006	0.0000	0.2505	0.7722	0.7722	0.7019	0.7019
NH_3	0.0000	0.0000	0.0000	0.0000	0.9724	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.0963	0.0963
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	45,275	45,275	45,275	672	274	74	0	1,303	222,646	12,417	278,713	278,713
V-L Flowrate (lb/hr)	866,680	866,680	866,680	21,582	4,771	2,808	0	29,653	6,424,310	358,284	7,972,540	7,972,540
Solids Flowrate (lb/hr)	0	0	0	0	0	0	10,452	0	0	0	0	0
Temperature (°F)	535	423	535	124	450	120	297	300	59	828	1,120	270
Pressure (psia)	695.0	380.0	375.0	375.0	364.5	28.0	22.6	15.5	14.7	282.2	14.8	14.7
Density (lb/ft^3)	1.25	0.77	0.67	2.09	0.68	0.18	--	0.04	0.08	0.59	0.03	0.06
Molecular Weight	19.14	19.14	19.14	32.14	17.43	37.78	--	22.76	28.85	28.85	28.60	28.60

2.3 Equipment Descriptions

Coal Preparation and Feed Systems

The coal as received contains 11.12 percent moisture, part of which is surface moisture (that which is easily removed from the coal) with the balance being inherent (chemically bound) moisture. For transportation of the coal at high pressure, drying of the surface moisture is required. For the purposes of this study, it was assumed that there is 5 percent inherent moisture in the coal and that the coal is dried to this level as a result. The coal is simultaneously crushed and dried using a combination of Claus tail gas and air. Crushed and dried coal is delivered to a surge hopper with an approximate 2-hour capacity.

The coal is drawn from the surge hoppers and fed through a developmental proprietary dry coal feed pump system, which uses nitrogen to convey the coal to the gasifiers.

Air Separation Unit

The air separation plant is designed to produce a nominal output of 3,700 tons/day of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 130 tons/day, is used in the Claus plant. The air compressor is powered by an electric motor. Approximately 11,000 tons/day of nitrogen are also recovered, compressed, and used for syngas dilution for NOx mitigation in the gas turbine combustor and as a carrying gas for coal transport into the gasifier.

Gasifier

The PWR gasifier is a plug-flow entrained reactor with a multi-port injection nozzle to increase the kinetics and conversion of the gasification reaction. The PWR gasification process gasifies dried coal with steam and 95% (by volume) oxygen at ~2600°F and 1,000 psia. The PWR process claims a 100% carbon conversion and faster kinetics allowing for a more compact gasifier design. The prototype reactor designed to process 3,000 tons of dried coal per day is anticipated to be 39 inches in diameter and 15 feet in length. The amount of dried coal processed is approximately 5,000 tons per day.

Syngas Cooling

Hot syngas and molten solids from the reactor flow downward through a radiant heat exchanger where the syngas is cooled to 1,000°F. High pressure steam is generated in the radiant cooler and is superheated in the HRSG by the gas turbine exhaust. The gas and solidified slag then flow into a water-filled quench chamber. Raw syngas saturated at about 380°F then flows to the syngas scrubber for removal of entrained solids. The solids collect in the water sump at the bottom of the gasifier and are removed periodically, using a lock hopper system.

Solids collected in the quench gasifier water sump are removed by gravity and forced circulation of water from the lock hopper circulating pump. Fine material, which does not settle as easily, is removed in the gasification blowdown which is sent to the vacuum flash drum by way of the syngas scrubber.

Syngas Scrubbing

The syngas enters the syngas scrubber and is directed downwards by a dip tube into a water sump at the bottom of the syngas scrubber. Most of the solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. From the overhead of the syngas scrubber, the syngas enters the low-temperature gas cooling section for further cooling.

The water removed from the syngas scrubber contains all the solids that were not removed in the quench gasifier water sump. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas scrubber. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating scrubbing water is pumped by the syngas scrubber circulating pumps to the quench gasifier.

The slag handling system removes solids from the gasification process equipment. These solids will consist of any unconverted carbon and essentially all of the ash contained in the feed coal. Since we have assumed 100% carbon conversion in this study, the "slag" will be 100% ash. These solids are in the form of glass, which is non-leaching and fully encapsulates any metals.

COS Hydrolysis / Low Temperature Gas Cooling

H_2S and COS are at significant concentrations, requiring removal for the power plant to achieve the low design level of SO_2 emissions. H_2S is removed in an acid gas removal process; however, because COS is not readily removable, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the quench/scrubber system, the gas is reheated to ~400°F and fed to the COS hydrolysis reactor. The COS is hydrolyzed with steam in the gas over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Any HCN in the syngas will also be reacted in the COS hydrolysis unit.

Before the raw fuel gas can be treated in the AGR process, it must be cooled to about 100°F. During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section.

Mercury Removal

Mercury removal was based on packed beds of sulfur-impregnated carbon similar to what has been used at Eastman Chemical's gasification plant. Dual beds of sulfur-impregnated carbon with approximately a 20-second superficial gas residence time should achieve >90 percent reduction of mercury in addition to removal of other volatile heavy metals such as arsenic.

Acid Gas Removal

Case 1 utilizes a single-train Selexol process to remove sulfur with minimal CO_2 capture. The Selexol process treats the stream of synthesis gas to reduce the level of total sulfur (H_2S and COS) to no more than 30 ppm prior to it being sent to the combustion turbine, while maximizing the CO_2 slip. A recycle stream of acid gas from the sulfur recovery unit (SRU) is also treated. An acid gas stream that contains ~50 percent sulfur is produced.

Untreated gas is sent to the absorber, where it contacts cooled regenerated solvent, which enters at the top of the tower. In the absorber, H_2S, COS, CO_2, and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent to fuel gas saturation and the expander.

The solvent streams from the absorber and reabsorber are termed rich solvent, and are combined and sent to the lean/rich exchanger. In the lean/rich exchanger, the temperature of the rich solvent is increased by heat exchange with the lean solvent. The rich solvent is then sent to the H_2S concentrator, where portions of the CO_2, CO, H_2, and other gases are stripped from the solvent. Nitrogen from the ASU is used as the stripping medium. The temperature of the overhead stream from the H_2S concentrator is reduced in the stripped gas cooler. The stream is then sent to the reabsorber, where H_2S, COS, and a portion of the other gases are transferred to the liquid phase. The stream from the reabsorber is sent to the gas turbine.

The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is regenerated. Tail gas from the SRU is recycled back to the AGR unit and enters with the feed to the reabsorber.

Sour Water Stripper

The sour water stripper removes NH_3, H_2S, and other impurities from the waste stream of the scrubber and water condensed in the low temperature gas cooling section. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from syngas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen instead of air followed by a SCOT tail gas unit. The Claus plant produces molten sulfur by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and SCOT tail gas technology will result in a sulfur recovery exceeding 99 percent of that fed to the Claus plant and a vent gas of less than 2 ppmv of SO_2.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 112 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stripper in the gasifier section. Vent gas from the tail gas treatment unit is vented to the coal dryer, contributing to total plant sulfur emissions of less than 0.022 lb/MMBtu, meeting air quality standards.

Syngas Expander

After sulfur removal, the sweet fuel gas is saturated with condensate, reheated, and depressurized through an expander from 695 psia to 380 psia, which is near the pressure required by the gas turbine. The expander generates ~12 MW_e of power.

Gas Turbine Generator

Both of the combustion turbine generators are General Electric 7FB model turbines modified for syngas firing. The maximum output of each is expected to be 232 MW, based on the rotor torque limit. Each machine is an axial flow, single spool, constant speed unit, equipped with variable inlet guide vanes and syngas version of diffusion-flame combustor with nitrogen diluent injection. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain.

The gas turbine generator selected for this application is based on a natural gas fired 7FB machine. In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the medium-Btu gas and expand the combustion products in the turbine section of the machine. A reduction in rotor inlet temperature of about 50°F is expected, relative to a production model 7FB machine firing natural gas. This temperature reduction may be necessary to not exceed design basis gas path temperatures throughout the expander. If the first-stage rotor inlet temperature were maintained at the design value, gas path temperatures downstream of the inlet to the first (HP) turbine stage may increase, relative to natural-gas-fired temperatures, due to gas property changes.

The syngas fired 7FB gas turbine is a developmental machine that GE expects to have available in the 2010 time frame for commercial applications.

Heat Recovery Steam Generator / Steam Turbine

The HRSG supplies steam to a steam turbine generator which is a tandem compound, two-flow exhaust, single reheat, condensing, GE model D-11, or equal. The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The overall power output from the steam turbine is 230.7 MWe.

2.4 Performance Results

For the Case 1 PWR IGCC plant, the combustion turbines are two General Electric 7FB model turbines in parallel, each producing 232 MWe for a total of 464 MWe. The steam turbine produces 230.7 MWe (gross), and the sweet gas expander produces 11.8 MWe. Total auxiliary power required is 101.3 MWe, yielding a net plant power output of 605.2 MWe.

Overall plant efficiency (HHV) is 42.2% equating to a heat rate of 8,078 Btu/kWh (HHV).

The performance results are summarized in Exhibit 11.

Exhibit 11
Case 1 - PWR IGCC Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Gas Turbine Power	464,000	kW_e
Sweet Gas Expander Gross Power	11,780	kW_e
Steam Turbine Power	230,670	kW_e
Total	**706,450**	$\mathbf{kW_e}$
Auxiliary Load		
Coal Handling	540	kW_e
Coal Milling	1,100	kW_e
Coal Pump	1,500	kW_e
Slag Handling	330	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	38,620	kW_e
Oxygen Compressor	9,330	kW_e
Nitrogen Compressor	25,800	kW_e
Gasifier N_2 Compressor	510	kW_e
Boiler Feedwater Pump	5,240	kW_e
Condensate Pump	230	kW_e
Circulating Water Pump	4,670	kW_e
Cooling Tower Fans	1,060	kW_e
Scrubber Pumps	300	kW_e
Selexol Unit Auxiliaries	2,700	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
Claus Plant/TGTU Auxiliaries	200	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	2,170	kW_e
Total	**101,300**	$\mathbf{kW_e}$
Plant Performance		
Net Plant Power	605,150	kW_e
Net Plant Efficiency (HHV)	42.2%	
Net Plant Heat Rate (HHV)	8,078	Btu/kWh
Coal Feed Flowrate	419,045	lb/hr
Thermal Input[1]	1,432,701	kW_t
Condenser Duty	1,125	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

2.5 Economic Results

The capital and operating costs estimate results are shown in Exhibit 12 through Exhibit 15. The Total Plant Cost is estimated to be 1,385 $/kW. At a 94%, 90% and 85% capacity factor, the Levelized Cost of Electricity is 45.4, 46.9 and 48.9 mills/kWh, respectively.

Exhibit 12
Case 1 - PWR IGCC Total Plant Capital Costs

Client: DEPARTMENT OF ENERGY **Report Date:** 20-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 1 Rocketdyne/GE Compact Gasifier IGCC for Power Production
Plant Size: 605.15 MW,net **Estimate Type:** Conceptual **Cost Base (December)** 2004 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOT. PLANT COST $	TOT. PLANT COST $/kW
1	COAL & SORBENT HANDLING	9,776	1,817	7,828	548	**19,969**	1,997		4,393	**$26,358**	$44
2	COAL & SORBENT PREP & FEED	12,900		9,968	137	**28,986**	2,899		6,377	**$38,261**	$63
3	FEEDWATER & MISC. BOP SYSTEMS	7,704		7,822	548	**22,450**	2,245		5,727	**$30,422**	$50
4	GASIFIER & ACCESSORIES										
4.1	Gasifiier and Water Quench	w/ 4.2	w/ 4.2								
4.2	Gasifier & Syngas Cooler	59,646	33,391	57,734	4,041	**154,812**	15,481		17,749	**$188,042**	$311
4.3	Air Separation Unit	61,415		w/equip.		**61,415**	6,141		3,378	**$70,934**	$117
4.4-4.9	Other Gasification Equipment	w/ 4.2	w/ 4.2								
	Subtotal 4	121,061	33,391	57,734	4,041	**216,227**	21,623		21,127	**$258,976**	$428
5	GAS & CLEANUP AND PIPING	29,619	3,634	29,203	2,044	**64,500**	6,450		10,333	**$81,283**	$134
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		13,167	**$144,840**	$239
6.2-6.9	Combustion Turbine Accessories		555	624	44	**1,223**	122		403	**$1,748**	$3
	Subtotal 6	115,259	555	4,777	334	**120,925**	12,093		13,571	**$146,589**	$242
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		3,838	**$42,215**	$70
7.2-7.9	SCR System, Ductwork and Stack	2,736	2,782	3,264	228	**9,010**	901		1,682	**$11,593**	$19
	Subtotal 7	33,276	2,782	7,328	513	**43,899**	4,390		5,519	**$53,808**	$89
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	25,093		3,126	219	**28,438**	2,844		3,128	**$34,410**	$57
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	6,698	615	4,673	327	**12,314**	1,231		2,346	**$15,891**	$26
	Subtotal 8	31,791	615	7,799	546	**40,751**	4,075		5,474	**$50,301**	$83
9	COOLING WATER SYSTEM	7,542	4,696	6,654	466	**19,358**	1,936		3,906	**$25,200**	$42
10	ASH/SPENT SORBENT HANDLING SYS	11,011	6,163	10,473	733	**28,380**	2,838		3,359	**$34,577**	$57
11	ACCESSORY ELECTRIC PLANT	13,368	5,955	15,451	1,082	**35,856**	3,586		6,673	**$46,114**	$76
12	INSTRUMENTATION & CONTROL	5,879		4,531	317	**11,617**	1,162		1,809	**$14,587**	$24
13	IMPROVEMENTS TO SITE	2,907	1,713	6,487	454	**11,561**	1,156		3,815	**$16,532**	$27
14	BUILDINGS & STRUCTURES		4,835	5,851	450	**11,136**	1,114		3,063	**$15,313**	$25
	TOTAL COST	**$402,093**	**$79,404**	**$181,906**	**$12,213**	**$675,615**	**$67,562**		**$95,146**	**$838,323**	**$1,385**

Exhibit 13
Case 1 - PWR IGCC Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION					**1/20/2006**
Case:	**Case 1 Rocketdyne/GE Compact Gasifier IGCC for Power Production**				
Plant Size:	**605.15 (MW,net)**		**Heat Rate**	**8,078**	**Btu/kWh**
Fuel(type):	**Illinois #6**		**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:	**3.5 (years)**		**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:	**2004**		**TPI Year:**	**2004**	**(Jan.)**
Capacity Factor:	**94.0%**		**CO2 Removed**		**(TPD)**

CAPITAL INVESTMENT			**$x1000**	**$/kW**
Process Capital & Facilities			675,615	1,116.4
Engineering(incl.C.M.,H.O.& Fee)			67,562	111.6
Process Contingency			0	0.0
Project Contingency			95,146	157.2
	TOTAL PLANT COST(TPC)		838,323	1,385.3
	TOTAL CASH EXPENDED	$838,323		
	AFDC	62,702		
	TOTAL PLANT INVESTMENT(TPI)		901,025	1,488.9
Royalty Allowance			1,000	1.7
Preproduction Costs			23,184	38.3
Inventory Capital			7,670	12.7
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$933,434	1,542.5
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**	**$/kW-yr**
Operating Labor			5,466	9.0
Maintenance Labor			9,521	15.7
Maintenance Material			18,045	29.8
Administrative & Support Labor			4,127	6.8
	TOTAL OPERATION & MAINTENANCE(2004)		$37,158	61.4
	FIXED O & M (2004)		$34,929	57.7
	VARIABLE O & M (2004)		$2,229	3.7
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**	**¢/kWh**
Water			4,504	0.09
Chemicals			3,862	0.08
Other Consumables			0	0.00
Waste Disposal			2,844	0.06
	TOTAL CONSUMABLES(2004)		$11,210	0.22
BY-PRODUCT CREDITS (2004)			($2,144)	(0.04)
FUEL COST(2004)			$51,120	1.03

		2004 Costs
PRODUCTION COST SUMMARY		**¢/kWh**
Fixed O & M		0.70
Variable O & M		0.04
Consumables		0.22
By-product Credit		(0.04)
Fuel		1.03
	TOTAL PRODUCTION COST	1.95
2004 CARRYING CHARGES (Capital)		2.59
	FCR=0.138	
2004 BUSBAR COST OF POWER		4.54

Exhibit 14
Case 1 - PWR IGCC Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION					
					1/20/2006
Case:	Case 1 Rocketdyne/GE Compact Gasifier IGCC for Power Production				
Plant Size:	605.15 (MW,net)		Heat Rate	8,078	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2004	(Jan.)
Capacity Factor:	90.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			**$x1000**	**$/kW**
Process Capital & Facilities			675,615	1,116.4
Engineering(incl.C.M.,H.O.& Fee)			67,562	111.6
Process Contingency			0	0.0
Project Contingency			95,146	157.2
	TOTAL PLANT COST(TPC)		838,323	1,385.3
	TOTAL CASH EXPENDED	$838,323		
	AFDC	62,702		
	TOTAL PLANT INVESTMENT(TPI)		901,025	1,488.9
Royalty Allowance			1,000	1.7
Preproduction Costs			23,145	38.2
Inventory Capital			7,449	12.3
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$933,174	1,542.1
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**	**$/kW-yr**
Operating Labor			5,466	9.0
Maintenance Labor			9,521	15.7
Maintenance Material			18,045	29.8
Administrative & Support Labor			4,127	6.8
	TOTAL OPERATION & MAINTENANCE(2004)		$37,158	61.4
	FIXED O & M (2004)		$33,442	55.3
	VARIABLE O & M (2004)		$3,716	6.1
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**	**¢/kWh**
Water			4,312	0.09
Chemicals			3,702	0.08
Other Consumables			0	0.00
Waste Disposal			2,723	0.06
	TOTAL CONSUMABLES(2004)		$10,737	0.23
BY-PRODUCT CREDITS (2004)			($2,052)	(0.04)
FUEL COST(2004)			$48,945	1.03

PRODUCTION COST SUMMARY		**2004 Costs ¢/kWh**
Fixed O & M		0.70
Variable O & M		0.08
Consumables		0.23
By-product Credit		(0.04)
Fuel		1.03
	TOTAL PRODUCTION COST	1.99
2004 CARRYING CHARGES (Capital)		2.70
	FCR=0.138	
2004 BUSBAR COST OF POWER		4.69

Exhibit 15
Case 1 - PWR IGCC Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					1/20/2006
Case:	Case 1 Rocketdyne/GE Compact Gasifier IGCC for Power Production				
Plant Size:	605.15 (MW,net)	Heat Rate	8,078 Btu/kWh		
Fuel(type):	Illinois #6	Fuel Cost:	1.27 ($/MMBtu)		
Design/Construction:	3.5 (years)	BookLife:	20 (years)		
TPC(Plant Cost) Year:	2004	TPI Year:	2004 (Jan.)		
Capacity Factor:	85.0%	CO2 Removed	(TPD)		

			$x1000		
CAPITAL INVESTMENT			$x1000		$/kW
Process Capital & Facilities			675,615		1,116.4
Engineering(incl.C.M.,H.O.& Fee)			67,562		111.6
Process Contingency			0		0.0
Project Contingency			95,146		157.2
	TOTAL PLANT COST(TPC)		838,323		1,385.3
	TOTAL CASH EXPENDED	$838,323			
	AFDC	62,702			
	TOTAL PLANT INVESTMENT(TPI)		901,025		1,488.9
Royalty Allowance			1,000		1.7
Preproduction Costs			23,096		38.2
Inventory Capital			7,016		11.6
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$932,692		1,541.3
OPERATING & MAINTENANCE COSTS(2004)			$x1000		$/kW-yr
Operating Labor			5,466		9.0
Maintenance Labor			9,521		15.7
Maintenance Material			18,045		29.8
Administrative & Support Labor			4,127		6.8
	TOTAL OPERATION & MAINTENANCE(2004)		$37,158		61.4
	FIXED O & M (2004)		$31,584		52.2
	VARIABLE O & M (2004)		$5,574		9.2
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			$x1000		¢/kWh
Water			4,072		0.09
Chemicals			3,502		0.08
Other Consumables			0		0.00
Waste Disposal			2,572		0.06
	TOTAL CONSUMABLES(2004)		$10,147		0.23
BY-PRODUCT CREDITS (2004)			($1,938)		(0.04)
FUEL COST(2004)			$46,226		1.03
				2004 Costs	
PRODUCTION COST SUMMARY				¢/kWh	
Fixed O & M				0.70	
Variable O & M				0.12	
Consumables				0.23	
By-product Credit				(0.04)	
Fuel				1.03	
	TOTAL PRODUCTION COST			2.03	
2004 CARRYING CHARGES (Capital)				2.86	
	FCR=0.138				
2004 BUSBAR COST OF POWER				4.89	

3 CASE 2 - GE ENERGY GASIFIER BASED IGCC PLANT DESCRIPTION AND RESULTS

Case 2 produces 634.8 MWe at 39.2% efficiency (8,669 BTU/kWh heat rate). The TPC is $972MM and, at 85% CF, produces electricity at 53.4 mills/kWh. Adding a spare gasification train increases the TPC to $1,057MM and, at 90% CF, results in a LCOE of 54.3 mills/kWh, and at 94% CF, results in a LCOE of 52.5 mills/kWh

A block flow diagram and associated stream tables for the Case 2 GE Energy gasifier-based IGCC plant in radiant quench heat recovery mode are presented in Exhibit 16 and Exhibit 17, respectively. Performance, capital costs and operating costs are presented in Exhibit 18 through Exhibit 23.

3.1 Process Description

Case 2 is similar to Case 1 with the following exceptions:

1. The gasifier used in Case 2 is the GE Energy Radiant Quench Gasifier with an operating pressure of 815 psia, as compared to 1,000 psia for the PWR gasifier.
2. A 63% coal/water slurry is fed to the GE gasifier while dry coal is fed to the PWR gasifier.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel is located a combination fuel injector through which coal slurry feedstock and oxidant (oxygen) are fed. The coal slurry and the oxygen feeds react in the gasifier at about 815 psia at a high temperature (in excess of 2500°F) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant cooler where the syngas is cooled to 1,000°F and the ash solidifies. Raw syngas continues downward into a quench system and then into a syngas scrubber for removal of entrained solids.

The gas goes through a series of gas coolers and cleanup processes including a COS hydrolysis reactor, a carbon bed mercury removal system, and a Selexol AGR plant. Slag captured by the syngas scrubber is recovered in a slag recovery unit. Regeneration gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

This plant utilizes a combined cycle for combustion of the syngas from the gasifier to generate electric power. Humidification of the syngas and nitrogen dilution aids in minimizing formation of NO_x during combustion in the gas turbine burner section. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process.

Exhibit 16
Case 2 - GE Energy IGCC Plant Block Flow Diagram

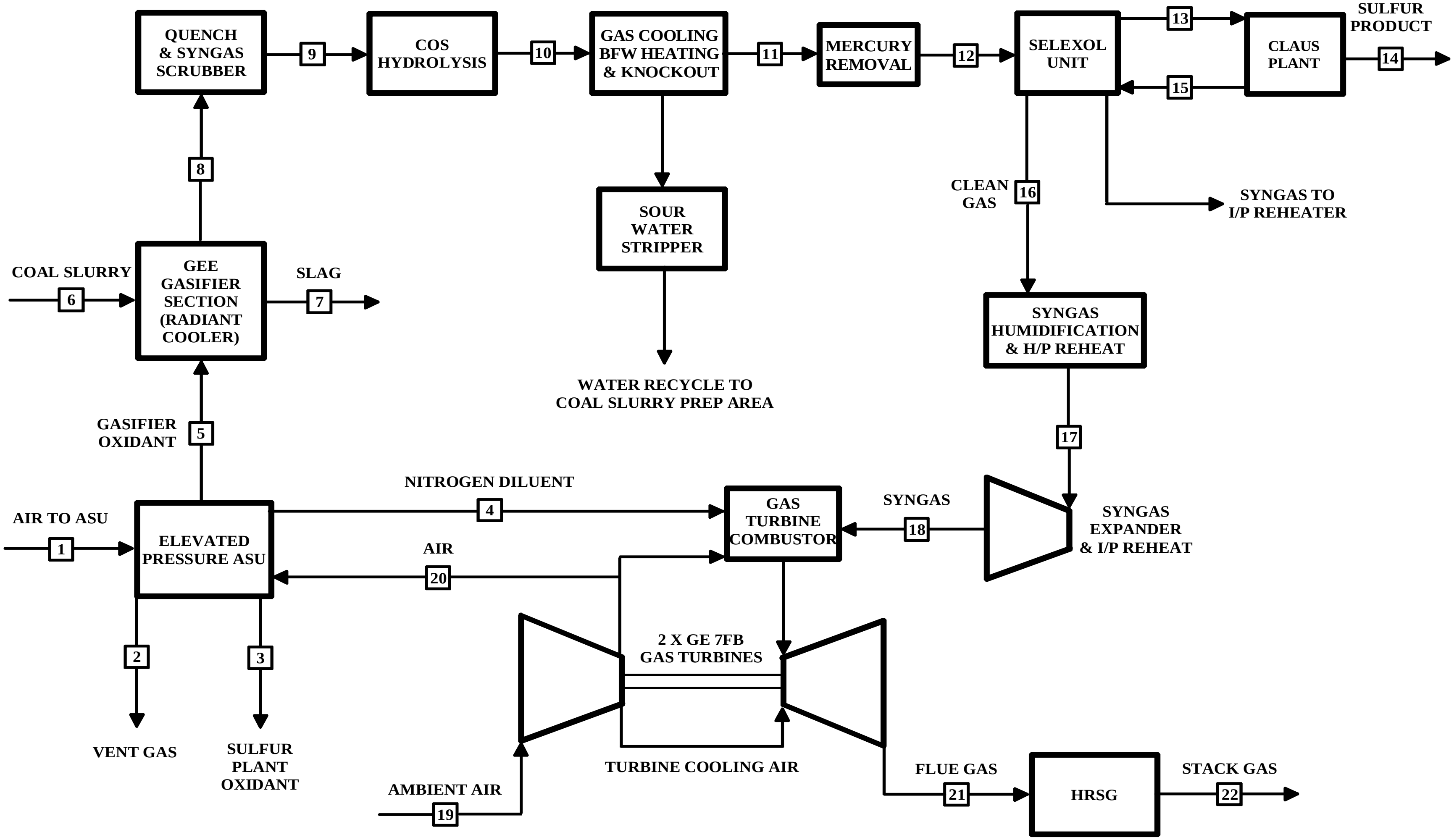

Exhibit 17
Case 2 - GE Energy IGCC Plant Stream Table

	1	2	3	4	5	6[A]	7	13	14
V-L Mole Fraction									
Ar	0.0094	0.0063	0.0360	0.0012	0.0360	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000
CO_2	0.0003	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.3102	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0104	0.0433	0.0000	0.0000	0.0000	1.0000	0.0000	0.0267	0.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4449	0.0000
N_2	0.7722	0.9098	0.0140	0.9988	0.0140	0.0000	0.0000	0.2175	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0393	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000
V-L Flowrate (lb_{mol}/hr)	48,684	14,324	180	33,932	12,295	13,728	0	822	0
V-L Flowrate (lb/hr)	1,404,740	398,709	5,795	950,561	396,246	247,104	0	29,134	0
Solids Flowrate (lb/hr)	0	0	0	0	0	420,739	51,961	0	11,839
Temperature (°F)	225	57	90	475	205	62	---	120	353
Pressure (psia)	190.0	16.4	30.0	375.0	1,024.7	814.7	---	30.0	23.6
Density (lb/ft^3)	0.746	0.085	0.164	1.047	4.632	---	---	0.171	---
Molecular Weight	28.854	27.835	32.229	28.013	32.229	---	---	35.435	---

A - Solids flowrate includes dry coal and soot recycle; V-L flowrate includes slurry water and water from coal
Note: Streams containing proprietary data are excluded from these stream tables.

Exhibit 17 (continued)
Case 2 - GE Energy IGCC Plant

	15	16	17	18	19	20	21	22
V-L Mole Fraction								
Ar	0.0121	0.0091	0.0091	0.0088	0.0094	0.0094	0.0088	0.0088
CH_4	0.0000	0.0007	0.0007	0.0006	0.0000	0.0000	0.0000	0.0000
CO	0.1762	0.3682	0.3682	0.3512	0.0000	0.0000	0.0000	0.0000
CO_2	0.3693	0.1048	0.1048	0.1310	0.0003	0.0003	0.0834	0.0834
COS	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0893	0.3326	0.3326	0.3142	0.0000	0.0000	0.0000	0.0000
H_2O	0.0022	0.1762	0.1762	0.1639	0.0104	0.0104	0.0906	0.0906
H_2S	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.3410	0.0084	0.0084	0.0301	0.7722	0.7722	0.7148	0.7148
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1025	0.1025
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	625	47,441	47,441	50,984	240,224	12,011	296,165	296,165
V-L Flowrate (lb/hr)	19,881	919,520	919,520	1,039,920	6,931,510	346,575	8,575,410	8,575,410
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	100	341	520	535	59	724	1,119	270
Pressure (psia)	368.0	700.0	695.0	370.0	14.7	225.6	14.8	14.7
Density (lb/ft^3)	1.950	1.595	1.281	0.707	0.076	0.512	0.025	0.056
Molecular Weight	31.809	19.383	19.383	20.397	28.854	28.854	28.955	28.955

3.2 Equipment Descriptions

Air Separation Unit

The air separation plant is designed to produce a nominal output of 4,900 tons/day of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 70 tons/day, is used in the Claus plant. The air compressor is powered by an electric motor. Approximately 11,000 tons/day of nitrogen are also recovered, compressed, and used as a diluent in the gas turbine combustor.

Gasifier

This GE IGCC plant utilizes two gasification trains to process a total of 5,700 tons per day of coal. The gasifier operates at near maximum capacity. The slurry feed pump takes suction from the slurry run tank, and the discharge is sent to the feed injector of the GEE gasifier. Oxygen from the ASU is vented during preparation for startup and is sent to the feed injector during normal operation. The air separation plant supplies 2,400 tons of 95 percent purity oxygen per day to each gasifier.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel is located a combination fuel injector through which coal slurry feedstock and oxidant (oxygen) are fed. The coal slurry and the oxygen feeds react in the gasifier at about 815 psia at a high temperature (in excess of 2,500°F) to produce syngas.

The syngas consists primarily of hydrogen and carbon monoxide, with lesser amounts of water vapor and carbon dioxide, and small amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, and nitrogen. The heat in the gasifier liquefies coal ash.

Syngas Cooling

Hot syngas and molten solids from the reactor flow downward through a radiant heat exchanger where the syngas is cooled to 1,000°F. High pressure steam is generated in the radiant cooler and is superheated in the HRSG by the gas turbine exhaust. The gas and solidified slag then flow into a water-filled quench chamber. Raw syngas, saturated at about 450°F, then flows to the syngas scrubber for removal of entrained solids. The solids collect in the water sump at the bottom of the gasifier and are removed periodically, using a lock hopper system.

Solids collected in the quench gasifier water sump are removed by gravity and forced circulation of water from the lock hopper circulating pump. Fine material, which does not settle as easily, is removed in the gasification blowdown which is sent to the vacuum flash drum by way of the syngas scrubber.

Syngas Scrubbing

Refer to Case 1 in section 2.3 for a description of the syngas scrubbing system used in Case 2, since they are similar.

COS Hydrolysis / Low Temperature Gas Cooling

Refer to Case 1 in section 2.3 for a description of the COS Hydrolysis and Low Temperature Gas Cooling systems used in Case 2, since they are similar.

Mercury Removal

Refer to Case 1 in section 2.3 for a description of the Mercury Removal system used in Case 2, since they are similar.

Acid Gas Removal

Refer to Case 1 in section 2.3 for a description of the Acid Gas Removal system used in Case 2, since they are similar.

Sour Water Stripper

Refer to Case 1 in section 2.3 for a description of the Sour Water Stripper used in Case 2, since they are similar.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by reacting approximately a third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 127 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stream in the gasifier section. Tail gas from the Claus unit, after hydrogenation, is recycled to the Selexol unit. The combination of Claus technology and tail gas recycle will result in an overall sulfur recovery exceeding 99 percent.

Syngas Expander

After sulfur removal, the sweet fuel gas is saturated with condensate, reheated, and depressurized through an expander from 695 psia to 370 psia, which is near the pressure required by the gas turbine. The expander generates ~12 MW_e of power.

Gas Turbine Generator

Refer to Case 1 in section 2.3 for a description of the gas turbine generator used in Case 2, since they are similar.

Heat Recovery Steam Generator / Steam Turbine

Refer to Case 1 in section 2.3 for a description of the HRSG and Steam Turbine used in Case 2, since they are similar. The overall power output from the steam turbine is 282 MWe (gross).

3.3 Performance Results

For Case 2, GE IGCC plant, the combustion turbines are two General Electric Model 7FB turbines in parallel, each producing 232 MWe for a total of 464 MWe. The steam turbine produces 282 MWe, and the sweet gas expander produces 12 MWe. Total auxiliary power required is 123 MWe, yielding a net plant power output of 635 MWe.

Overall plant efficiency (HHV) is 39.2%, with a heat rate of 8,699 Btu/kWh.

The performance results are summarized in Exhibit 18.

Exhibit 18
Case 2 - GE Energy IGCC Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Gas Turbine Power	464,000	kW_e
Sweet Gas Expander Gross Power	11,920	kW_e
Steam Turbine Power	282,150	kW_e
Total	**758,070**	$\mathbf{kW_e}$
Auxiliary Load		
Coal Handling	90	kW_e
Coal Milling	2,210	kW_e
Coal Slurry Pumps	530	kW_e
Slag Handling and Dewatering	1,130	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	56,520	kW_e
Oxygen Compressor	11,090	kW_e
Nitrogen Compressor	26,020	kW_e
Plant Tail Gas Recycle Compressor	980	kW_e
Boiler Feedwater Pump	5,200	kW_e
Condensate Pump	220	kW_e
Flash Bottoms Pump	200	kW_e
Circulating Water Pump	5,430	kW_e
Cooling Tower Fans	1,230	kW_e
Scrubber Pumps	250	kW_e
Selexol Unit Auxiliaries	2,730	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
Claus Plant/TGTU Auxiliaries	200	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	2,210	kW_e
Total	**123,240**	$\mathbf{kW_e}$
Plant Performance		
Net Auxiliary Load	123,240	kW_e
Net Plant Power	634,830	kW_e
Net Plant Efficiency (HHV)	39.2%	
Net Plant Heat Rate (HHV)	8,699	Btu/kWh
Coal Feed Flowrate	473,379	lb/hr
Thermal Input[1]	1,618,468	kW_t
Condenser Duty	1,306	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

3.4 Economic Results

The capital and operating costs results for Case 2, GE IGCC are shown in Exhibit 19 through Exhibit 23. The Total Plant Cost with a dual gasifier train is estimated to be 1,532 $/kW and 1,665 $/kW for a plant with a redundant three gasifier train. At 94% and 90% capacity factors, the Levelized Cost of Electricity for the redundant train arrangements are 52.5 and 54.3 mills/kWh, respectively. At 85% capacity factor, the LCOE for the dual train arrangement is 53.4 mills/kWh.

Exhibit 19
Case 2 - GE Energy IGCC Total Plant Capital Costs with a Dual Gasifier Train

Client: DEPARTMENT OF ENERGY **Report Date:** 17-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 2 -GEE Radiant 500MW IGCC w/o CO2
Plant Size: 634.83 MW,net **Estimate Type:** Conceptual **Cost Base (December)** 2004 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOT. PLANT COST $	TOT. PLANT COST $/kW
1	COAL & SORBENT HANDLING	10,495	2,003	8,486	594	**21,578**	2,158		4,747	**$28,483**	$45
2	COAL & SORBENT PREP & FEED	16,205		12,499	875	**37,867**	3,787		5,176	**$46,830**	$74
3	FEEDWATER & MISC. BOP SYSTEMS	8,664		8,497	595	**25,298**	2,530		6,376	**$34,204**	$54
4	GASIFIER & ACCESSORIES										
4.1	Syngas Cooler Gasification System	68,505	30,077	52,814	3,697	**155,093**	15,509		17,060	**$187,663**	$296
4.2	Syngas Cooler (w/Gasifier-$)	w/4.1									
4.3	ASU/Oxidant Compression	76,473		w/equip.		**76,473**	7,647		4,206	**$88,326**	$139
4.4-4.9	Other Gasification Equipment	15,372	15,245	18,527	1,297	**50,441**	5,044		6,268	**$61,753**	$97
	Subtotal 4	160,350	45,322	71,341	4,994	**282,007**	28,201		27,534	**$337,742**	$532
5	GAS & CLEANUP AND PIPING	32,893	4,033	32,243	2,257	**71,426**	7,143		11,421	**$89,990**	$142
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		13,167	**$144,840**	$228
6.2-6.9	Combustion Turbine Accessories		555	624	44	**1,223**	122		403	**$1,748**	$3
	Subtotal 6	115,259	555	4,777	334	**120,925**	12,093		13,571	**$146,589**	$231
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		3,838	**$42,215**	$66
7.2-7.9	SCR System, Ductwork and Stack	4,237	3,413	4,555	319	**12,524**	1,252		2,261	**$16,038**	$25
	Subtotal 7	34,777	3,413	8,619	603	**47,412**	4,741		6,099	**$58,253**	$92
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	31,851		3,968	278	**36,097**	3,610		3,971	**$43,677**	$69
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	8,502	781	5,932	415	**15,630**	1,563		2,978	**$20,171**	$32
	Subtotal 8	40,353	781	9,900	693	**51,727**	5,173		6,949	**$63,848**	$101
9	COOLING WATER SYSTEM	9,573	5,961	8,446	591	**24,571**	2,457		4,958	**$31,987**	$50
10	ASH/SPENT SORBENT HANDLING SYS	12,139	6,794	11,545	808	**31,288**	3,129		3,703	**$38,120**	$60
11	ACCESSORY ELECTRIC PLANT	13,890	6,188	16,054	1,124	**37,256**	3,726		6,934	**$47,915**	$75
12	INSTRUMENTATION & CONTROL	6,109		4,708	330	**12,071**	1,207		1,879	**$15,157**	$24
13	IMPROVEMENTS TO SITE	2,907	1,713	6,487	454	**11,561**	1,156		3,815	**$16,532**	$26
14	BUILDINGS & STRUCTURES		5,240	6,450	451	**12,142**	1,214		3,340	**$16,696**	$26
	TOTAL COST	**$463,614**	**$98,758**	**$210,053**	**$14,703**	**$787,129**	**$78,713**		**$106,504**	**$972,345**	**$1,532**

Exhibit 20
Case 2 - GE Energy IGCC Total Plant Capital Costs with a Redundant Gasifier Train

Client: DEPARTMENT OF ENERGY **Report Date:** 17-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 2 -GEE Radiant 500MW IGCC w/o CO2
Plant Size: 634.83 MW,net **Estimate Type:** Conceptual **Cost Base (December)** 2004 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	10,495	2,003	8,486	594	**21,578**	2,158		4,747	**$28,483**	$45
2	COAL & SORBENT PREP & FEED	16,205		12,499	875	**37,867**	3,787		5,176	**$46,830**	$74
3	FEEDWATER & MISC. BOP SYSTEMS	8,664		8,497	595	**25,298**	2,530		6,376	**$34,204**	$54
4	GASIFIER & ACCESSORIES										
4.1	Syngas Cooler Gasification System	100,000	45,000	75,000	5,250	**225,250**	22,525		24,778	**$272,553**	$429
4.2	Syngas Cooler (w/Gasifier-$)	w/4.1									
4.3	ASU/Oxidant Compression	76,473		w/equip.		**76,473**	7,647		4,206	**$88,326**	$139
4.4-4.9	Other Gasification Equipment	15,372	15,245	18,527	1,297	**50,441**	5,044		6,268	**$61,753**	$97
	Subtotal 4	191,845	60,245	93,527	6,547	**352,164**	35,216		35,251	**$422,632**	$666
5	GAS & CLEANUP AND PIPING	32,893	4,033	32,243	2,257	**71,426**	7,143		11,421	**$89,990**	$142
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		13,167	**$144,840**	$228
6.2-6.9	Combustion Turbine Accessories		555	624	44	**1,223**	122		403	**$1,748**	$3
	Subtotal 6	115,259	555	4,777	334	**120,925**	12,093		13,571	**$146,589**	$231
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		3,838	**$42,215**	$66
7.2-7.9	SCR System, Ductwork and Stack	4,237	3,413	4,555	319	**12,524**	1,252		2,261	**$16,038**	$25
	Subtotal 7	34,777	3,413	8,619	603	**47,412**	4,741		6,099	**$58,253**	$92
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	31,851		3,968	278	**36,097**	3,610		3,971	**$43,677**	$69
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	8,502	781	5,932	415	**15,630**	1,563		2,978	**$20,171**	$32
	Subtotal 8	40,353	781	9,900	693	**51,727**	5,173		6,949	**$63,848**	$101
9	COOLING WATER SYSTEM	9,573	5,961	8,446	591	**24,571**	2,457		4,958	**$31,987**	$50
10	ASH/SPENT SORBENT HANDLING SYS	12,139	6,794	11,545	808	**31,288**	3,129		3,703	**$38,120**	$60
11	ACCESSORY ELECTRIC PLANT	13,890	6,188	16,054	1,124	**37,256**	3,726		6,934	**$47,915**	$75
12	INSTRUMENTATION & CONTROL	6,109		4,708	330	**12,071**	1,207		1,879	**$15,157**	$24
13	IMPROVEMENTS TO SITE	2,907	1,713	6,487	454	**11,561**	1,156		3,815	**$16,532**	$26
14	BUILDINGS & STRUCTURES		5,240	6,450	451	**12,142**	1,214		3,340	**$16,696**	$26
	TOTAL COST	**$495,109**	**$113,681**	**$232,239**	**$16,256**	**$857,286**	**$85,729**		**$114,221**	**$1,057,235**	**$1,665**

Exhibit 21
Case 2 - GE Energy IGCC Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION					**12/29/2005**
Case:	**Case 2 -GEE Radiant 500MW IGCC w/o CO2**				
Plant Size:		**634.83 (MW,net)**	**Heat Rate**	**8,699.0**	**Btu/kWh**
Fuel(type):		**Illinois #6**	**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:		**3.5 (years)**	**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:		**2004**	**TPI Year:**	**2010**	**(Jan.)**
Capacity Factor:		**94.0%**	**CO2 Removed**		**(TPD)**
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			857,286		1,350.4
Engineering(incl.C.M.,H.O.& Fee)			85,729		135.0
Process Contingency			0		0.0
Project Contingency			114,221		179.9
	TOTAL PLANT COST(TPC)		1,057,235		1,665.4
	TOTAL CASH EXPENDED	$1,057,235			
	AFDC	79,076			
	TOTAL PLANT INVESTMENT(TPI)		1,136,311		1,789.9
Royalty Allowance			1,000		1.6
Preproduction Costs			28,760		45.3
Inventory Capital			8,492		13.4
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$1,175,118		1,851.1
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**		**$/kW-yr**
Operating Labor			5,466		8.6
Maintenance Labor			12,008		18.9
Maintenance Material			22,755		35.8
Administrative & Support Labor			4,127		6.5
	TOTAL OPERATION & MAINTENANCE(2004)		$44,357		69.9
	FIXED O & M (2004)		$41,696		65.7
	VARIABLE O & M (2004)		$2,661		4.2
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**		**¢/kWh**
Water			4,711		0.09
Chemicals			4,761		0.09
Other Consumables			0		0.00
Waste Disposal			3,213		0.06
	TOTAL CONSUMABLES(2004)		$12,685		0.24
BY-PRODUCT CREDITS (2004)			($2,437)		(0.05)
FUEL COST(2004)			$57,749		1.10
				2004 Costs	
PRODUCTION COST SUMMARY				**¢/kWh**	
Fixed O & M				0.80	
Variable O & M				0.05	
Consumables				0.24	
By-product Credit				(0.05)	
Fuel				1.10	
	TOTAL PRODUCTION COST			2.15	
2004 CARRYING CHARGES (Capital)				3.10	
	FCR=0.138				
2004 BUSBAR COST OF POWER				5.25	

Exhibit 22
Case 2 - GE Energy IGCC Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION						**12/29/2005**
Case:	**Case 2 -GEE Radiant 500MW IGCC w/o CO2**					
Plant Size:		**634.83**	**(MW,net)**	**Heat Rate**	**8,699.0**	**Btu/kWh**
Fuel(type):		**Illinois #6**		**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:		**3.5**	**(years)**	**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:		**2004**		**TPI Year:**	**2010**	**(Jan.)**
Capacity Factor:		**90.0%**		**CO2 Removed**		**(TPD)**
CAPITAL INVESTMENT				**$x1000**		**$/kW**
Process Capital & Facilities				857,286		1,350.4
Engineering(incl.C.M.,H.O.& Fee)				85,729		135.0
Process Contingency				0		0.0
Project Contingency				114,221		179.9
	TOTAL PLANT COST(TPC)			1,057,235		1,665.4
	TOTAL CASH EXPENDED	$1,057,235				
	AFDC	79,076				
	TOTAL PLANT INVESTMENT(TPI)			1,136,311		1,789.9
Royalty Allowance				1,000		1.6
Preproduction Costs				28,715		45.2
Inventory Capital				8,243		13.0
Initial Catalyst & Chemicals(w/equip.)						
Land Cost				555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)			$1,174,824		1,850.6
OPERATING & MAINTENANCE COSTS(2004)				**$x1000**		**$/kW-yr**
Operating Labor				5,466		8.6
Maintenance Labor				12,008		18.9
Maintenance Material				22,755		35.8
Administrative & Support Labor				4,127		6.5
	TOTAL OPERATION & MAINTENANCE(2004)			$44,357		69.9
	FIXED O & M (2004)			$39,921		62.9
	VARIABLE O & M (2004)			$4,436		7.0
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)				**$x1000**		**¢/kWh**
Water				4,511		0.09
Chemicals				4,563		0.09
Other Consumables				0		0.00
Waste Disposal				3,076		0.06
	TOTAL CONSUMABLES(2004)			$12,150		0.24
BY-PRODUCT CREDITS (2004)				($2,333)		(0.05)
FUEL COST(2004)				$55,291		1.10
					2004 Costs	
PRODUCTION COST SUMMARY					**¢/kWh**	
Fixed O & M					0.80	
Variable O & M					0.09	
Consumables					0.24	
By-product Credit					(0.05)	
Fuel					1.10	
	TOTAL PRODUCTION COST				2.19	
2004 CARRYING CHARGES (Capital)					3.24	
	FCR=0.138					
2004 BUSBAR COST OF POWER					5.43	

Exhibit 23
Case 2 - GE Energy IGCC Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					**12/29/2005**
Case:	**Case 2 -GEE Radiant 500MW IGCC w/o CO2**				
Plant Size:	**634.83 (MW,net)**		**Heat Rate**	**8,699.0**	**Btu/kWh**
Fuel(type):	**Illinois #6**		**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:	**3.5 (years)**		**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:	**2004**		**TPI Year:**	**2010**	**(Jan.)**
Capacity Factor:	**85.0%**		**CO2 Removed**		**(TPD)**
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			787,129		1,239.9
Engineering(incl.C.M.,H.O.& Fee)			78,713		124.0
Process Contingency			0		0.0
Project Contingency			106,504		167.8
	TOTAL PLANT COST(TPC)		972,345		1,531.7
	TOTAL CASH EXPENDED	$972,345			
	AFDC	72,727			
	TOTAL PLANT INVESTMENT(TPI)		1,045,072		1,646.2
Royalty Allowance			1,000		1.6
Preproduction Costs			26,602		41.9
Inventory Capital			7,773		12.2
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$1,081,002		1,702.8
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**		**$/kW-yr**
Operating Labor			5,466		8.6
Maintenance Labor			11,044		17.4
Maintenance Material			20,928		33.0
Administrative & Support Labor			4,127		6.5
	TOTAL OPERATION & MAINTENANCE(2004)		$41,566		65.5
	FIXED O & M (2004)		$35,331		55.7
	VARIABLE O & M (2004)		$6,235		9.8
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**		**¢/kWh**
Water			4,260		0.09
Chemicals			4,315		0.09
Other Consumables			0		0.00
Waste Disposal			2,905		0.06
	TOTAL CONSUMABLES(2004)		$11,481		0.24
BY-PRODUCT CREDITS (2004)			($2,204)		(0.05)
FUEL COST(2004)			$52,220		1.10
				2004 Costs	
PRODUCTION COST SUMMARY				**¢/kWh**	
Fixed O & M				0.75	
Variable O & M				0.13	
Consumables				0.24	
By-product Credit				(0.05)	
Fuel				1.10	
	TOTAL PRODUCTION COST			2.18	
2004 CARRYING CHARGES (Capital)				3.16	
	FCR=0.138				
2004 BUSBAR COST OF POWER				5.34	

4 CASE 3 - PWR GASIFIER BASED IGCC PLANT DESCRIPTION AND RESULTS

Case 3 produces 613.7 MWe at 42.9% efficiency (7,957 BTU/kWh heat rate). The total plant cost excluding a spare gasification train is $743MM, which equates to a LCOE at 85% CF of 44.6 mills/kWh.

A block flow diagram and associated stream tables for the Case 3 PWR gasifier-based IGCC plant in syngas quench/convective syngas cooler heat recovery mode are presented in Exhibit 24 and Exhibit 25, respectively. Performance, capital costs and operating costs are presented in Exhibit 26 through Exhibit 30.

4.1 Process Description

The Case 3 PWR IGCC plant consists of two compact gasifiers each fed with approximately 1,800 tpd of 95% oxygen produced via an on site Air Separation Unit (ASU) and approximately 2,500 tpd of Illinois #6 coal dried from 11.12% to 5% in a syngas/HRSG gas-fired coal dryer. The assumption that Illinois #6 coal has 5% inherent moisture has been made, but should be verified in the next stage of design. Each gasifier train in the PWR process requires approximately 140 tpd of pure nitrogen as coal transport gas as well as approximately 390 tpd of steam injection.

The PWR process claims an adiabatic flame temperature of ~2600°F, 1,000 psig operating pressure, and 100% carbon conversion. Approximately 490 tpd of slag (100% ash) is removed from the gasification reaction products (replicating the Case 4, Shell partial quench with recycle gas and convective cooling) followed with a candle filter and scrubber to separate the entrained slag. At this point, the syngas is heated to 400°F before entering a hydrolysis reactor, where >99% of the carbonyl sulfide is converted to hydrogen sulfide. The gas is cooled to ~100°F, is cleaned of ammonia and mercury prior to feeding the gas to the acid gas removal system.

A conventional Sulfinol-M process separates the syngas into an acid gas stream containing hydrogen sulfide and carbon dioxide and into a sweet gas stream containing the fuel gas to be combusted in the gas turbine. The acid gas stream is sent to a two bed Claus sulfur recovery plant with a tail gas clean up unit. Using approximately 113 tpd of 95% oxygen, the Claus process catalytically converts the gaseous sulfur compounds into elemental sulfur for collection and sale. A hydrogenation reactor converts the remaining gaseous sulfur dioxide into hydrogen sulfide, which may be separated from the tail gas in an MDEA tail gas treating unit. H_2S is then recycled back to the Claus plant thermal reaction zone to improve overall sulfur recovery.

The clean synthesis gas stream exits the Sulfinol-M unit at approximately 125°F, where it is humidified with hot water at 370°F. The humidifier accomplishes some reheating of the syngas while partially diluting the gas for NOx mitigation in the gas turbine combustors. After sulfur removal, the sweet fuel gas is also depressurized through an expander from 695 psia to 380 psia to generate ~11 MW_e of power.

Further reheating of the syngas, to 535°F, improves the gas turbine heat rate by reducing the amount of combustion energy used for heating the gas. In order to minimize NOx formation, the synthesis gas must be diluted to ~120 Btu/scf (LHV basis). Approximately 11,000 tpd of nitrogen diluent and 2,400 tpd of steam are added to accomplish the dilution. The resultant fuel gas stream is combined with compressed and heated ambient air then combusted in two parallel General Electric 7FB model turbines.

The combustion products exiting the gas turbines are fed to a HRSG for heat recovery and additional power production before discharge to the atmosphere.

4.2 Modeling Assumptions for PWR Gasifier

Refer to Section 2.2 for a detailed discussion on the modeling assumptions used for PWR gasifier performance prediction in this study.

Exhibit 24
Case 3 - PWR Convective IGCC Plant Block Flow Diagram

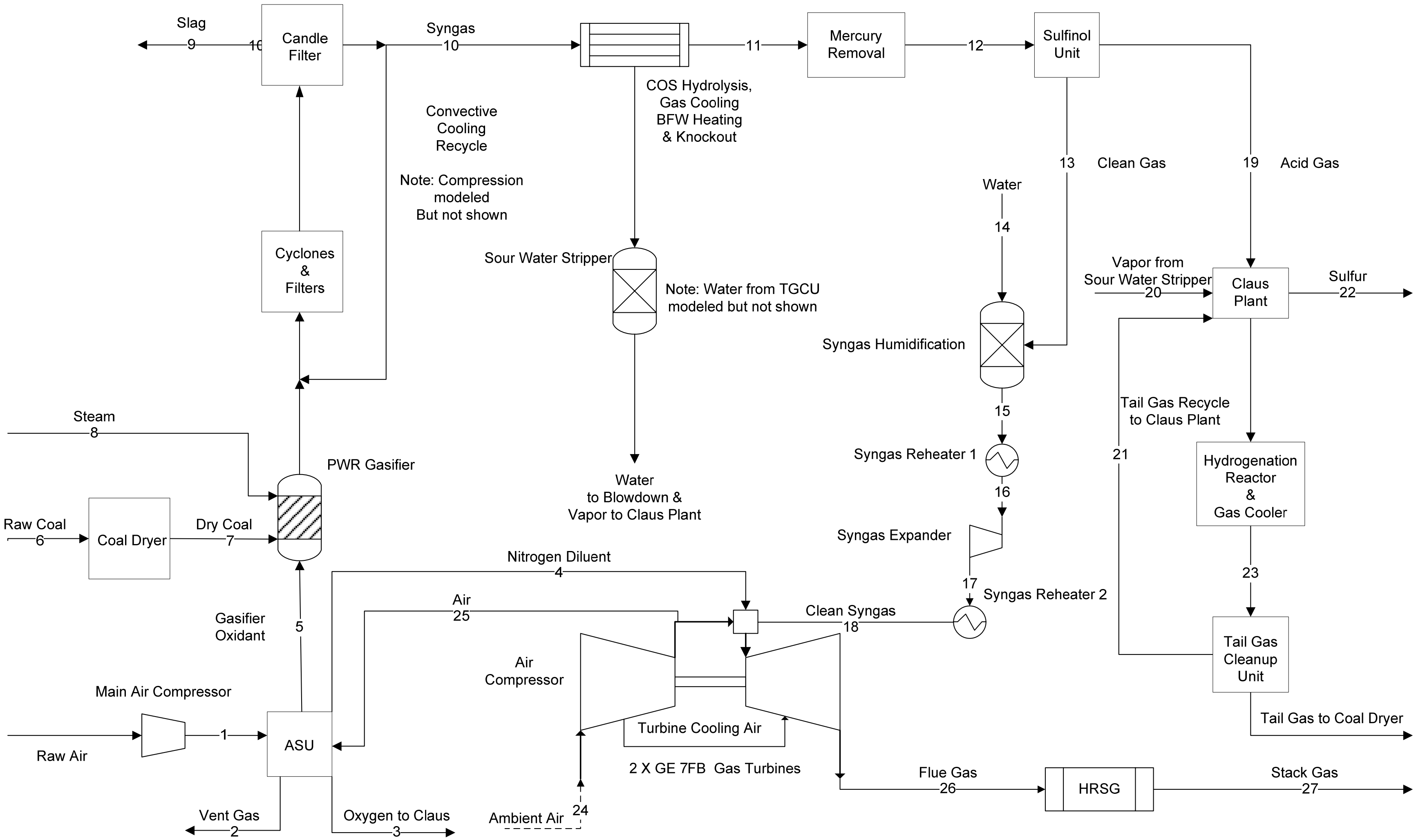

Exhibit 25
Case 3 - PWR Convective IGCC Plant Stream Table

	1	2	3	4	5	6[A]	7[A]	8	9	13	14	15
V-L Mole Fraction												
Ar	0.0094	0.0594	0.0322	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0000	0.0016
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6076	0.0000	0.5072
CO_2	0.0003	0.0138	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0121	0.0000	0.0101
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3383	0.0000	0.2824
H_2O	0.0104	0.4392	0.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0009	1.0000	0.1660
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.4876	0.0178	1.0000	0.0500	0.0000	0.0000	0.0000	0.0000	0.0393	0.0000	0.0328
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	30,775	1,024	293	31,919	9,257	2,586	1,088	3,587	0	35,292	7,468	42,279
V-L Flowrate (lb/hr)	887,988	25,135	9,431	894,172	294,374	46,545	19,580	64,622	0	683,915	134,420	809,784
Solids Flowrate (lb/hr)	0	0	0	0	0	372,029	372,029	0	40,588	0	0	0
Temperature (°F)	271	70	90	450	800	59	195	800	650	124	367	337
Pressure (psia)	225.0	16.4	125.0	375.0	1,191.2	14.7	550.0	1,200.0	975.0	768.0	890.0	700.0
Density (lb/ft^3)	0.83	0.12	0.682	1.08	2.76	--	--	1.60	--	2.38	51.18	1.58
Molecular Weight	28.85	24.55	32.18	28.01	31.80	--	--	18.02	--	19.38	18.02	19.15

A - Solids flowrate includes coal; V-L flowrate includes water from coal (11.12 wt% moisture)
Note: Streams containing proprietary data are excluded from these stream tables.

Exhibit 25 (continued)
Case 3 - PWR Convective IGCC Plant Stream Table

	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0082	0.0094	0.0094	0.0071	0.0071
CH_4	0.0016	0.0016	0.0016	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.5072	0.5072	0.5072	0.0042	0.0067	0.0000	0.0000	0.0050	0.0000	0.0000	0.0000	0.0000
CO_2	0.0101	0.0101	0.0101	0.4531	0.0030	0.7115	0.0000	0.2823	0.0003	0.0003	0.0789	0.0789
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000
H_2	0.2824	0.2824	0.2824	0.0024	0.0006	0.0003	0.0000	0.1305	0.0000	0.0000	0.0000	0.0000
H_2O	0.1660	0.1660	0.1660	0.0057	0.0000	0.0391	0.0000	0.4418	0.0104	0.0104	0.1160	0.1160
H_2S	0.0000	0.0000	0.0000	0.5344	0.0068	0.2490	0.0000	0.0251	0.0000	0.0000	0.0000	0.0000
N_2	0.0328	0.0328	0.0328	0.0002	0.0004	0.0002	0.0000	0.1071	0.7722	0.7722	0.7017	0.7017
NH_3	0.0000	0.0000	0.0000	0.0000	0.9824	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.0962	0.0962
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	42,279	42,279	42,279	607	271	124	0	1,282	222,574	12,413	278,728	278,728
V-L Flowrate (lb/hr)	809,784	809,784	809,784	23,294	4,680	5,024	0	32,015	6,422,210	358,167	7,967,270	7,967,270
Solids Flowrate (lb/hr)	0	0	0	0	0	0	10,414	0	0	0	0	0
Temperature (°F)	535	421	535	124	450	120	297	300	59	828	1,120	270
Pressure (psia)	695.0	380.0	375.0	375.0	364.5	28.0	22.6	15.5	14.7	282.2	14.8	14.7
Density (lb/ft^3)	1.25	0.77	0.67	2.31	0.67	0.18	--	0.05	0.08	0.59	0.03	0.05
Molecular Weight	19.15	19.15	19.15	38.39	17.30	40.51	--	24.97	28.85	28.85	28.58	28.58

4.3 Equipment Descriptions

Coal Preparation and Feed Systems

The coal as received contains 11.12 percent moisture, and must be dried to 5 percent or less moisture. The coal is simultaneously crushed and dried using a combination of Claus tail gas and air. Crushed and dried coal is delivered to a surge hopper with an approximate 2-hour capacity.

The coal is drawn from the surge hoppers and fed through a developmental proprietary dry coal feed pump system, which uses nitrogen to convey the coal to the gasifiers.

Air Separation Unit

The air separation plant is designed to produce a nominal output of 3,700 tons/day of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 110 tons/day, is used in the Claus plant. The air compressor is powered by an electric motor. Approximately 11,000 tons/day of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor.

Gasifier

The PWR gasifier uses a plug-flow entrained reactor and a multi-port injection nozzle to increase the kinetics and conversion of the gasification reaction. The PWR gasification process gasifies dried coal with steam and 95% (by volume) oxygen at ~2600°F and 1,000 psia. The PWR process claims a 100% carbon conversion and faster kinetics allowing for a more compact gasifier design. The prototype reactor designed to process 3,000 tons of dried coal per day is anticipated to be 39 inches in diameter and 15 feet in length. The amount of dried coal processed in this study is approximately 5,000 tons per day.

Syngas Cooling

High-temperature cooling heat recovery in each gasifier train is accomplished in two steps. The product gas from the gasifier is cooled to ~1650°F by adding cooled recycled fuel gas to lower the temperature below the ash melting point. Gas then goes through a convective raw gas cooler, which lowers the gas temperature from ~1650°F to 650°F, and produces high-pressure steam for use in the steam cycle. Boiler feedwater in the tube walls is saturated, and then steam and water are separated in a steam drum. Approximately 1.1 MMlb/hour of saturated steam at 1800 psia is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

Particulate Removal

A candle filter is used to remove any particulate material exiting the secondary gasification zone. The filter is comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with fuel gas to remove the fines material.

Synthesis Gas Recycle Compressor

A fraction of the raw gas from the filter is recycled back to the gasifier as quench gas. A single-stage compressor is utilized to boost the pressure of a cooled fuel gas stream and provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubbing

The "sour" gas leaving the particulate filter system consists mostly of hydrogen, CO_2, CO, water vapor, nitrogen, and smaller quantities of methane, carbonyl sulfide (COS), H_2S, and NH_3.

The sour gas is cooled to 95ºF before H_2S is removed. The cooling is accomplished by several heat exchangers, where water in the syngas condenses; the condensate contains NH_3 and some of the H_2S and CO_2. The sour condensate is sent to water treatment.

The raw synthesis gas exiting the ceramic particulate filter then enters the scrubber for particulate removal at 450°F. The quench scrubber washes the syngas in a counter-current flow in two packed beds. After leaving the scrubber at a temperature of 310ºF, the gas has a residual soot content of less than 1 mg/m^3. The quench scrubber removes essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. The bottoms from the scrubber are sent to the slag removal and handling system for processing.

The syngas enters the syngas scrubber and is directed downwards by a dip tube into a water sump at the bottom of the syngas scrubber. Most of the solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. From the overhead of the syngas scrubber, the syngas enters the low-temperature gas cooling section for further cooling.

The slag handling system removes solids from the gasification process equipment. These solids normally consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. For this study, 100% carbon conversion was assumed. As a result, the "slag" is 100% ash. These solids are in the form of glass, which is non-leaching and fully encapsulates any metals.

COS Hydrolysis / Low Temperature Gas Cooling

H_2S and COS are at significant concentrations, requiring removal for the power plant to achieve the low design level of SO_2 emissions. H_2S is removed in an acid gas removal process; however, because COS is not readily removable, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the quench/scrubber system, the gas is reheated to 400°F and fed to the COS hydrolysis reactor. The COS is hydrolyzed with steam in the gas over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Any HCN in the syngas will also be reacted in the COS hydrolysis unit.

Before the raw fuel gas can be treated in the AGR process, it must be cooled to about 100°F. During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section.

Mercury Removal

Mercury removal was based on packed beds of sulfur-impregnated carbon similar to what has been used at Eastman Chemical's gasification plant. Dual beds of sulfur-impregnated carbon with approximately a 20-second superficial gas residence time of should achieve >90 percent reduction of mercury in addition to removal of other volatile heavy metals such as arsenic.

Acid Gas Removal

The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA), while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than straight aqueous amines. Sulfinol-M was selected for this application.

The acid gas stream, consisting of hydrogen sulfide and carbon dioxide, is separated from the syngas by physical and chemical absorption in the Sulfinol solvent. The rich Sulfinol solvent is regenerated in a stripping column and is then recycled back to the absorber as lean solvent in a continuous loop. The stripping column feeds the acid gas taken from the Sulfinol solvent to the Claus plant for sulfur recovery.

Sour Water Stripper

The sour water stripper removes NH_3, H_2S, and other impurities from the waste stream of the scrubber and water condensed in the low temperature gas cooling section. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from syngas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen instead of air followed by a SCOT tail gas unit. The Claus plant produces molten sulfur by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and SCOT tail gas technology will result in a sulfur recovery exceeding 99 percent of that fed to the Claus plant and a vent gas of less than 2 ppmv of SO_2.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 112 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stripper in the gasifier section. Vent gas from the tail gas treatment unit is vented to the coal dryer, contributing to total plant sulfur emissions of less than 0.033 lb/MMBtu, meeting air quality standards.

Syngas Expander

After sulfur removal, the sweet fuel gas is saturated with condensate, reheated, and depressurized through an expander from 695 psia to 380 psia, which is near the pressure required by the gas turbine. The expander generates ~11 MW_e of power.

Gas Turbine Generator

Both of the combustion turbine generators are General Electric 7FB model turbines modified for syngas firing. The maximum output of each is expected to be 232 MW, based on the rotor torque limit. Each machine is an axial flow, single spool, constant speed unit, equipped with variable inlet guide vanes and syngas version of diffusion-flame combustor with nitrogen diluent injection. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain.

The gas turbine generator selected for this application is based on a natural gas fired 7FB machine. In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the medium-Btu gas and expand the combustion products in the turbine section of the machine. A reduction in rotor inlet temperature of about 50°F is expected, relative to a production model 7FB machine firing natural gas. This temperature reduction may be necessary to not exceed design basis gas path temperatures throughout the expander. If the first-stage rotor inlet temperature were maintained at the design value, gas path temperatures downstream of the inlet to the first (HP) turbine stage may increase, relative to natural-gas-fired temperatures, due to gas property changes.

The syngas fired 7FB gas turbine is a developmental machine that GE expects to have available in the 2010 time frame for commercial applications.

Heat Recovery Steam Generator / Steam Turbine

The HRSG supplies steam to a steam turbine generator which is a tandem compound, two-flow exhaust, single reheat, condensing, GE model D-11, or equal. The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The overall power output from the steam turbine is 240 MWe.

4.4 Performance Results

For Case 3, the combustion turbines are two General Electric 7FB model turbines in parallel, each producing 232 MWe for a total of 464 MWe. The steam turbine produces 240 MWe, and the sweet gas expander produces 11 MWe. Total auxiliary power required is 101 MWe, yielding a net plant power output of 614 MWe.

Overall plant efficiency (HHV) is 42.9%, with a heat rate of 7,957 Btu/kWh.

The performance results are summarized in Exhibit 26.

Exhibit 26
Case 3 - PWR Convective IGCC
Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Gas Turbine Power	464,000	kW_e
Sweet Gas Expander Gross Power	10,920	kW_e
Steam Turbine Power	239,870	kW_e
Total	**714,790**	**kW_e**
Auxiliary Load		
Coal Handling	540	kW_e
Coal Milling	1,090	kW_e
Dry Coal Pump	1,500	kW_e
Slag Handling	330	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	38,300	kW_e
Oxygen Compressor	9,470	kW_e
Nitrogen Compressor	26,150	kW_e
Syngas Recycle Compressor	1,870	kW_e
Boiler Feedwater Pump	5,590	kW_e
Condensate Pump	230	kW_e
Circulating Water Pump	4,780	kW_e
Cooling Tower Fans	1,080	kW_e
Scrubber Pumps	300	kW_e
Sulfinol Unit Auxiliaries	500	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
Claus Plant/TGTU Auxiliaries	200	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	2,200	kW_e
Total	**101,130**	**kW_e**
Plant Performance		
Net Plant Power	613,660	kW_e
Net Plant Efficiency (HHV)	42.9%	
Net Plant Heat Rate (HHV)	7,957	Btu/kWh
Coal Feed Flowrate	418,574	lb/hr
Thermal Input[1]	1,431,091	kW_t
Condenser Duty	1,150	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

4.5 Economic Results

The capital and operating costs estimate results are shown in Exhibit 27 through Exhibit 30. The Total Plant Cost is estimated to be 1,211 $/kW. At a 94%, 90% and 85% capacity factor, the Levelized Cost of Electricity is 41.5, 42.8 and 44.6 mills/kWh, respectively.

Exhibit 27
Case 3 - PWR Convective IGCC Total Plant Capital Costs

Client: DEPARTMENT OF ENERGY — **Report Date:** 17-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 3 -Rocketdyne/Shell IGCC
Plant Size: 613.66 MW,net — **Estimate Type:** Conceptual — **Cost Base (December)** 2005 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOT. PLANT COST $	TOT. PLANT COST $/kW
1	COAL & SORBENT HANDLING	9,776	1,817	7,828	548	**19,969**	1,997		4,393	**$26,358**	$43
2	COAL & SORBENT PREP & FEED	12,900		9,968	137	**28,986**	2,899		6,377	**$38,261**	$62
3	FEEDWATER & MISC. BOP SYSTEMS	7,704		7,822	548	**22,450**	2,245		5,727	**$30,422**	$50
4	GASIFIER & ACCESSORIES										
4.1	PWR Gasification System	w/ 4.2	w/ 4.2								
4.2	Syngas Cooler w/Gasifier	52,462	13,198	24,360	1,706	**91,726**	9,173		12,079	**$112,977**	$184
4.3	ASU/Oxidant Compression	61,415		w/equip.		**61,415**	6,141		3,378	**$70,934**	$116
4.4-4.9	Other Gasification Equipment	w/ 4.2	w/ 4.2								
	Subtotal 4	113,877	13,198	24,360	1,706	**153,140**	15,314		15,456	**$183,911**	$300
5	GAS & CLEANUP AND PIPING	19,843	3,819	17,412	1,219	**42,293**	4,229		8,044	**$54,566**	$89
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		13,167	**$144,840**	$236
6.2-6.9	Combustion Turbine Accessories	3,327	555	1,272	89	**5,243**	524		846	**$6,613**	$11
	Subtotal 6	118,586	555	5,425	380	**124,946**	12,495		14,013	**$151,453**	$247
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		3,838	**$42,215**	$69
7.2-7.9	SCR System, Ductwork and Stack	2,736	2,782	3,264	228	**9,010**	901		1,682	**$11,593**	$19
	Subtotal 7	33,276	2,782	7,328	513	**43,899**	4,390		5,519	**$53,808**	$88
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	28,015		2,958	207	**31,180**	3,118		3,430	**$37,728**	$61
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	6,096	560	4,253	298	**11,207**	1,121		2,135	**$14,462**	$24
	Subtotal 8	34,111	560	7,211	505	**42,387**	4,239		5,565	**$52,190**	$85
9	COOLING WATER SYSTEM	7,542	4,696	6,654	466	**19,358**	1,936		3,906	**$25,200**	$41
10	ASH/SPENT SORBENT HANDLING SYS	11,011	6,163	10,473	733	**28,380**	2,838		3,359	**$34,577**	$56
11	ACCESSORY ELECTRIC PLANT	13,368	5,955	15,451	1,082	**35,856**	3,586		6,673	**$46,114**	$75
12	INSTRUMENTATION & CONTROL	5,879		4,531	317	**11,617**	1,162		1,809	**$14,587**	$24
13	IMPROVEMENTS TO SITE	2,907	1,713	6,487	454	**11,561**	1,156		3,815	**$16,532**	$27
14	BUILDINGS & STRUCTURES		4,835	5,851	450	**11,136**	1,114		3,063	**$15,313**	$25
	TOTAL COST	**$390,780**	**$59,341**	**$136,801**	**$9,056**	**$595,977**	**$59,598**		**$87,719**	**$743,294**	**$1,211**

Exhibit 28
Case 3 - PWR Convective IGCC Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION						1/20/2006
Case:	Case 3 -Rocketdyne/Shell IGCC					
Plant Size:		613.66	(MW,net)	Heat Rate	7,957	Btu/kWh
Fuel(type):		Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:		3.5	(years)	BookLife:	20	(years)
TPC(Plant Cost) Year:		2004		TPI Year:	2004	(Jan.)
Capacity Factor:		94.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			**$x1000**	**$/kW**
Process Capital & Facilities			595,977	971.2
Engineering(incl.C.M.,H.O.& Fee)			59,598	97.1
Process Contingency			0	0.0
Project Contingency			87,719	142.9
	TOTAL PLANT COST(TPC)		743,294	1,211.2
	TOTAL CASH EXPENDED	$743,294		
	AFDC	55,595		
	TOTAL PLANT INVESTMENT(TPI)		798,888	1,301.8
Royalty Allowance			1,000	1.6
Preproduction Costs			20,985	34.2
Inventory Capital			7,395	12.1
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$828,823	1,350.6
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**	**$/kW-yr**
Operating Labor			5,466	8.9
Maintenance Labor			8,442	13.8
Maintenance Material			15,998	26.1
Administrative & Support Labor			4,127	6.7
	TOTAL OPERATION & MAINTENANCE(2004)		$34,034	55.5
	FIXED O & M (2004)		$31,992	52.1
	VARIABLE O & M (2004)		$2,042	3.3
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**	**¢/kWh**
Water			4,711	0.09
Chemicals			4,546	0.09
Other Consumables			0	0.00
Waste Disposal			3,209	0.06
	TOTAL CONSUMABLES(2004)		$12,466	0.25
BY-PRODUCT CREDITS (2004)			($2,437)	(0.05)
FUEL COST(2004)			$51,063	1.01

		2004 Costs
PRODUCTION COST SUMMARY		**¢/kWh**
Fixed O & M		0.63
Variable O & M		0.04
Consumables		0.25
By-product Credit		(0.05)
Fuel		1.01
	TOTAL PRODUCTION COST	1.88
2004 CARRYING CHARGES (Capital)		2.26
	FCR=0.138	
2004 BUSBAR COST OF POWER		4.15

Exhibit 29
Case 3 - PWR Convective IGCC Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION					1/20/2006
Case:	Case 3 -Rocketdyne/Shell IGCC				
Plant Size:	613.66 (MW,net)		Heat Rate	7,957	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2004	(Jan.)
Capacity Factor:	90.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			**$x1000**	**$/kW**
Process Capital & Facilities			595,977	971.2
Engineering(incl.C.M.,H.O.& Fee)			59,598	97.1
Process Contingency			0	0.0
Project Contingency			87,719	142.9
	TOTAL PLANT COST(TPC)		743,294	1,211.2
	TOTAL CASH EXPENDED	$743,294		
	AFDC	55,595		
	TOTAL PLANT INVESTMENT(TPI)		798,888	1,301.8
Royalty Allowance			1,000	1.6
Preproduction Costs			20,940	34.1
Inventory Capital			7,170	11.7
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$828,553	1,350.2
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**	**$/kW-yr**
Operating Labor			5,466	8.9
Maintenance Labor			8,442	13.8
Maintenance Material			15,998	26.1
Administrative & Support Labor			4,127	6.7
	TOTAL OPERATION & MAINTENANCE(2004)		$34,034	55.5
	FIXED O & M (2004)		$30,631	49.9
	VARIABLE O & M (2004)		$3,403	5.5
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**	**¢/kWh**
Water			4,511	0.09
Chemicals			4,352	0.09
Other Consumables			0	0.00
Waste Disposal			3,073	0.06
	TOTAL CONSUMABLES(2004)		$11,936	0.25
BY-PRODUCT CREDITS (2004)			($2,333)	(0.05)
FUEL COST(2004)			$48,890	1.01

		2004 Costs
PRODUCTION COST SUMMARY		**¢/kWh**
Fixed O & M		0.63
Variable O & M		0.07
Consumables		0.25
By-product Credit		(0.05)
Fuel		1.01
	TOTAL PRODUCTION COST	1.91
2004 CARRYING CHARGES (Capital)		2.36
	FCR=0.138	
2004 BUSBAR COST OF POWER		4.28

Exhibit 30
Case 3 - PWR Convective IGCC Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					**1/20/2006**
Case:	**Case 3 -Rocketdyne/Shell IGCC**				
Plant Size:	**613.66 (MW,net)**		**Heat Rate**	**7,957**	**Btu/kWh**
Fuel(type):	**Illinois #6**		**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:	**3.5 (years)**		**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:	**2004**		**TPI Year:**	**2004**	**(Jan.)**
Capacity Factor:	**85.0%**		**CO2 Removed**		**(TPD)**
CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			595,977		971.2
Engineering(incl.C.M.,H.O.& Fee)			59,598		97.1
Process Contingency			0		0.0
Project Contingency			87,719		142.9
	TOTAL PLANT COST(TPC)		743,294		1,211.2
	TOTAL CASH EXPENDED	$743,294			
	AFDC	55,595			
	TOTAL PLANT INVESTMENT(TPI)		798,888		1,301.8
Royalty Allowance			1,000		1.6
Preproduction Costs			20,885		34.0
Inventory Capital			6,888		11.2
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$828,217		1,349.6
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**		**$/kW-yr**
Operating Labor			5,466		8.9
Maintenance Labor			8,442		13.8
Maintenance Material			15,998		26.1
Administrative & Support Labor			4,127		6.7
	TOTAL OPERATION & MAINTENANCE(2004)		$34,034		55.5
	FIXED O & M (2004)		$28,929		47.1
	VARIABLE O & M (2004)		$5,105		8.3
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**		**¢/kWh**
Water			4,260		0.09
Chemicals			4,111		0.09
Other Consumables			0		0.00
Waste Disposal			2,902		0.06
	TOTAL CONSUMABLES(2004)		$11,273		0.25
BY-PRODUCT CREDITS (2004)			($2,204)		(0.05)
FUEL COST(2004)			$46,174		1.01
				2004 Costs	
PRODUCTION COST SUMMARY				**¢/kWh**	
Fixed O & M				0.63	
Variable O & M				0.11	
Consumables				0.25	
By-product Credit				(0.05)	
Fuel				1.01	
	TOTAL PRODUCTION COST			1.95	
2004 CARRYING CHARGES (Capital)				2.50	
	FCR=0.138				
2004 BUSBAR COST OF POWER				4.46	

5 CASE 4 - SHELL GASIFIER BASED IGCC PLANT DESCRIPTION AND RESULTS

Case 4 produces 624.6 MWe at 42.0% efficiency (8,130 BTU/kWh heat rate). The plant costs $949MM and, at 85% CF, provides electricity at 52.8 mills/kWh. A plant with a redundant gasifier train costs $1,045MM and at 90% CF, provides electricity at 54.2 mills/kWh, and at 94% CF, provides electricity at 52.5 mills/kWh

A block flow diagram and associated stream tables for the Case 4 Shell gasifier-based IGCC plant in syngas quench/convective syngas cooling heat recovery mode are presented in Exhibit 31 and Exhibit 32, respectively. Performance, capital costs and operating costs are presented in Exhibit 33 through Exhibit 38.

5.1 Process Description

Case 4 is similar to Case 3 with the following exception:

- The gasifier used in Case 4 is the Shell Gasifier with an operating pressure of 465 psia.

This IGCC plant design is based on the Shell Global Solutions gasification technology, which utilizes a pressurized entrained-flow dry-feed gasifier to meet the syngas fuel requirements for two General Electric 7FB combustion turbines. The ASU supplies 95 percent pure oxygen to the gasifier.

The pressurized entrained-flow Shell gasifier uses a dry-coal feed and oxygen to produce a medium heating value fuel gas. The syngas produced in the gasifier at about 2700°F is quenched to around 1650°F by cooled recycled syngas. The syngas passes through a convective cooler and leaves near 650°F. High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply.

Raw gas leaving the syngas cooler is cleaned of particulate matter and passes through a COS hydrolysis reactor before entering a Sulfinol-M acid gas removal process. Elemental sulfur is produced as a salable byproduct. The clean gas exiting the AGR system is conveyed to the combustion turbines where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the combustion turbine and HRSG is released to the atmosphere via a conventional stack.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling modules).

The hot combustion gases are conveyed to the inlet of the turbine section, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to a separate stack.

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gas, as well as utilizing steam generation opportunities in the gasifier process. As the turbine exhaust gas passes through the HRSG, it progressively transfers heat for reheating steam (cold reheat to hot reheat), superheating main steam, and generating main steam in an HP drum. The HRSG also generates and superheats steam from an IP drum (as reheat, and for use in the integral deaerator), and heats feedwater.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one casing, with the LP section in a second casing.

Exhibit 31
Case 4 - Shell Gasifier-Based IGCC Plant Block Flow Diagram

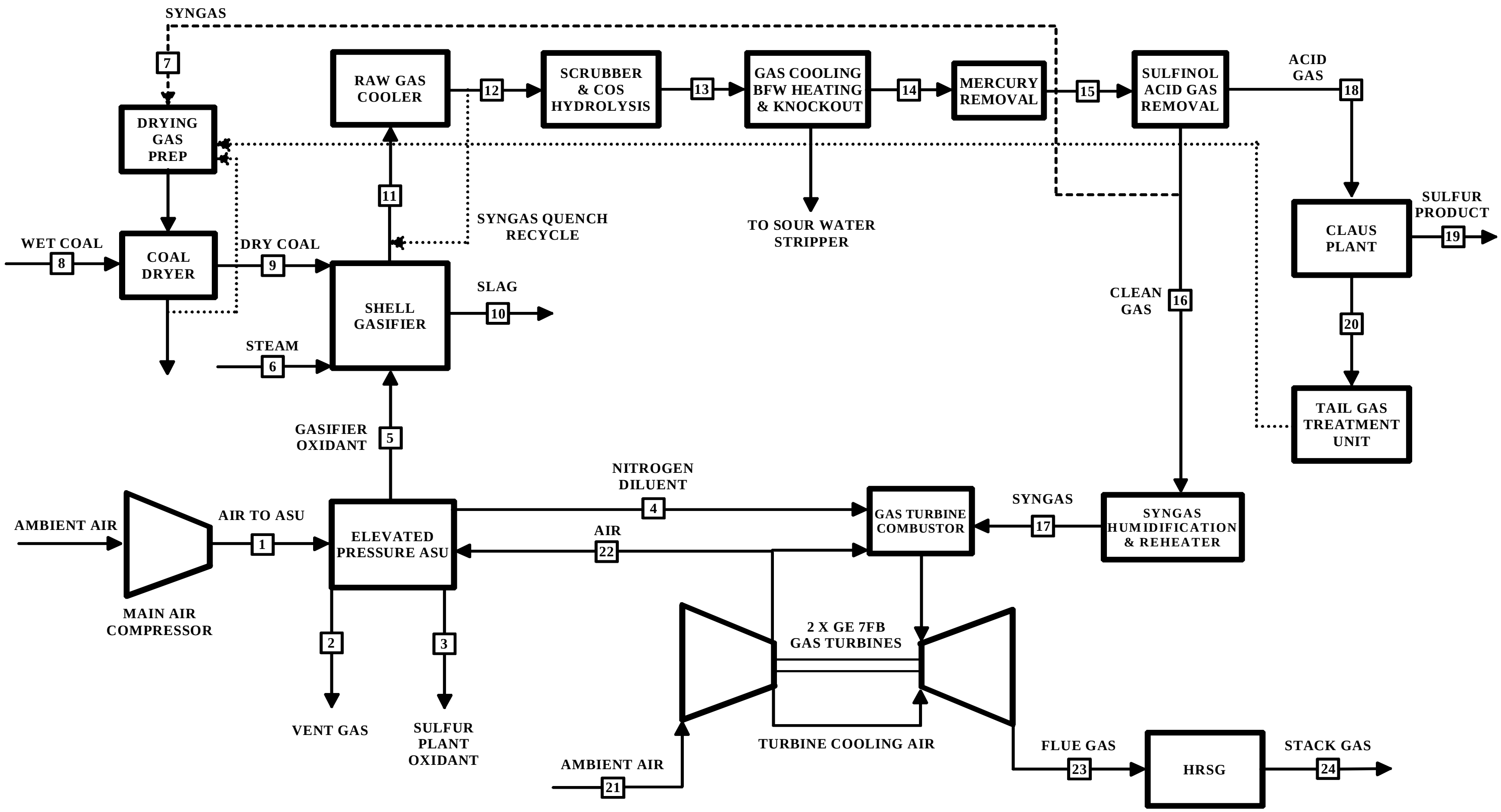

Exhibit 32
Case 4 - Shell Gasifier-Based IGCC Plant Stream Table

	1	2	3	4	5	6	7	8[A]	9[A]	10
V-L Mole Fraction										
Ar	0.0094	0.0145	0.0360	0.0000	0.0360	0.0000	0.0105	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6152	0.0000	0.0000	0.0000
CO_2	0.0003	0.0046	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3140	0.0000	0.0000	0.0000
H_2O	0.0104	0.1413	0.0000	0.0000	0.0000	1.0000	0.0020	1.0000	1.0000	0.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.7247	0.0140	1.0000	0.0140	0.0000	0.0576	0.0000	0.0000	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.1149	0.9500	0.0000	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000
V-L Flowrate (lb_{mol}/hr)	40,000	3,717	181	37,283	10,461	2,331	450	2,688	1,131	0
V-L Flowrate (lb/hr)	1,154,180	101,484	5,840	1,044,430	337,137	41,989	8,988	48,390	20,356	0
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	386,771	386,771	44,394
Temperature (°F)	255	63	90	448	208	450	124	300	1,650	448
Pressure (psia)	190.0	16.4	30.0	300.0	650.0	500.0	357.0	464.4	464.4	430.9
Density (lb/ft^3)	0.715	0.091	0.164	0.863	2.925	47.395	1.138	---	---	---
Molecular Weight	28.854	27.305	32.229	28.013	32.229	18.015	19.962	---	---	---

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal
Note: Streams containing proprietary data are excluded from these stream tables.

Exhibit 32 (continued)
Case 4 - Shell Gasifier-Based IGCC Plant Stream Table

	16	17	18	19	20	21	22	23	24
V-L Mole Fraction									
Ar	0.0105	0.0086	0.0003	0.0000	0.0038	0.0094	0.0094	0.0086	0.0086
CH_4	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.6152	0.5051	0.0113	0.0000	0.0549	0.0000	0.0000	0.0000	0.0000
CO_2	0.0006	0.0005	0.6300	0.0000	0.5500	0.0003	0.0003	0.0760	0.0760
COS	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000
H_2	0.3140	0.2577	0.0063	0.0000	0.0122	0.0000	0.0000	0.0000	0.0000
H_2O	0.0020	0.1807	0.0062	0.0000	0.2982	0.0104	0.0104	0.0738	0.0738
H_2S	0.0000	0.0000	0.2617	0.0000	0.0017	0.0000	0.0000	0.0000	0.0000
N_2	0.0576	0.0473	0.0842	0.0000	0.0762	0.7722	0.7722	0.7372	0.7372
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1043	0.1043
SO_2	0.0000	0.0000	0.0000	0.0000	0.0028	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	35,402	43,125	1,290	0	1,847	235,560	11,778	287,742	287,742
V-L Flowrate (lb/hr)	706,714	845,840	50,914	0	62,205	6,796,930	339,846	8,347,350	8,347,350
Solids Flowrate (lb/hr)	0	0	0	10,891	0	0	0	0	0
Temperature (°F)	124	530	124	344	280	59	724	1,120	270
Pressure (psia)	357.0	345.0	60.0	23.6	23.6	14.7	225.6	14.8	14.7
Density (lb/ft^3)	1.138	0.637	0.378	---	0.101	0.076	0.512	0.025	0.056
Molecular Weight	19.962	19.614	39.458	---	33.679	28.854	28.854	29.010	29.010

5.2 Equipment Descriptions

Coal Preparation and Feed Systems

The coal as received contains 11.12 percent moisture, and must be dried to 5 percent or less moisture. The coal is simultaneously crushed and dried. Crushed and dried coal is delivered to a surge hopper with an approximate 2-hour capacity.

The coal is drawn from the surge hoppers and fed through a pressurization lock hopper system to a dense phase pneumatic conveyor, which uses nitrogen to convey the coal to the gasifiers.

Air Separation Unit

The air separation plant is designed to produce a nominal output of 4,100 tpd of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 70 tpd, is used in the Claus plant. The air compressor is powered by an electric motor. Approximately 12,500 tpd of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor.

Gasifier

There are two Shell entrained-flow gasifiers, operating at 465 psia each processing 2,440 tons per day of dry coal. Sized coal is stored in surge hoppers, which serve as a reserve of raw material for the pressurization lock hoppers below. Coal is pressurized and fluidized with nitrogen, and transported to horizontally opposed burners on each gasifier along with 240 tpd steam, 2,020 tpd oxygen and recirculated solids from the raw gas filter. Gas exits the gasifier at 1650°F, and contains elutriated particulate matter. The gas passes through the raw gas cooler and then through the raw gas filter in which a majority of the fine particles are removed and are returned to the gasifier with the coal fuel.

Fines produced by the gasification system are recirculated to extinction. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form. The slag is solidified in a quench tank for disposal. A pressure reduction system is used to reduce the pressure of the solids from 465 to 15 psia.

Syngas Cooling

High-temperature cooling heat recovery in each gasifier train is accomplished in two steps. The product gas from the gasifier is cooled to 1650°F by adding cooled recycled fuel gas to lower the temperature below the ash melting point. Gas then goes through a raw gas cooler, which lowers the gas temperature from 1650°F to 650°F, and produces high-pressure steam for use in the steam cycle.

Hot raw gas after quenching from the gasification zone exits the gasifier and is cooled to 650ºF in a convective cooler. The waste heat from this cooling is used to generate high-pressure steam. Boiler feedwater in the tube walls is saturated, and then steam and water are separated in a steam drum. Approximately 830,000 lb/hour of saturated steam at 1800 psia is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

Particulate Removal

A candle filter is used to remove any particulate material exiting the secondary gasification zone. This material, char and fly ash, is recycled back to the gasifier. The filter is comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with fuel gas to remove the fines material. Raw gas exits the candle filter at 448ºF and 431 psia.

Syngas Recycle Compressor

A fraction of the raw gas from the filter is recycled back to the gasifier as quench gas. A single-stage compressor is utilized to boost the pressure of a cooled fuel gas stream from 431 psia to 470 psia to provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubbing

The "sour" gas leaving the particulate filter system consists mostly of hydrogen, CO_2, CO, water vapor, nitrogen, and smaller quantities of methane, carbonyl sulfide (COS), H_2S, and NH_3.

The sour gas is cooled to 95ºF before H_2S is removed. The cooling is accomplished by several heat exchangers, where water in the syngas condenses; the condensate contains NH_3 and some of the H_2S and CO_2. The sour condensate is sent to water treatment.

The raw synthesis gas exiting the ceramic particulate filter at 448°F then enters the scrubber for particulate removal. The quench scrubber washes the syngas in a counter-current flow in two packed beds. After leaving the scrubber at a temperature of 230ºF, the gas has a residual soot content of less than 1 mg/m^3. The quench scrubber removes essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. The bottoms from the scrubber are sent to the slag removal and handling system for processing.

COS Hydrolysis

Refer to Case 3 in section 4.3 for a description of the COS Hydrolysis system used in Case 4, since they are similar.

Mercury Removal

Refer to Case 3 in section 4.3 for a description of the Mercury Removal system used in Case 4, since they are similar.

Acid Gas Removal

Refer to Case 3 in section 4.3 for a description of the Acid Gas Removal system used in Case 4, since they are similar.

Sour Water Stripper

Refer to Case 3 in section 4.3 for a description of the Acid Gas Removal system used in Case 4, since they are similar.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen instead of air followed by a SCOT tail gas unit. The Claus plant produces molten sulfur by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and SCOT tail gas technology will result in an overall sulfur recovery exceeding 99 percent and a vent gas of less than 2 ppmv of SO_2.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 117 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stripper in the gasifier section. Vent gas from the tail gas treatment unit is vented to the coal dryer.

Gas Turbine Generator

Refer to Case 3 in section 4.3 for a description of the Gas Turbine Generator used in Case 4, since they are similar.

Heat Recovery Steam Generator / Steam Turbine

Refer to Case 3 in section 4.3 for a description of the HRSG and Steam Turbine used in Case 4, since they are similar. The overall power output from the steam turbine is 270.4 MWe.

5.3 Performance Results

For Case 4, the combustion turbines are two General Electric Model 7FB turbines in parallel, each producing 232 MWe for a total of 464 MWe. The steam turbine produces 270 MWe. Total auxiliary power required is 110 MWe, yielding a net plant power output of 625 MWe.

Overall plant efficiency (HHV) is 42.0%, with a heat rate of 8,130 Btu/kWh.

The performance results are summarized in Exhibit 33.

Exhibit 33
Case 4 - Shell Gasifier-Based IGCC Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Gas Turbine Power	464,000	kW_e
Steam Turbine Power	270,370	kW_e
Total	**734,370**	**kW_e**
Auxiliary Load		
Coal Handling	80	kW_e
Coal Milling	2,030	kW_e
Slag Handling	520	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	46,460	kW_e
Oxygen Compressor	7,450	kW_e
Nitrogen Compressor	29,390	kW_e
Plant Tail Gas Recycle Compressor	2,240	kW_e
Incinerator Air Blower	110	kW_e
Boiler Feedwater Pump	4,080	kW_e
Condensate Pump	250	kW_e
Circulating Water Pump	5,810	kW_e
Cooling Tower Fans	1,310	kW_e
Scrubber Pumps	300	kW_e
Sulfinol Unit Auxiliaries	340	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
Claus Plant/TGTU Auxiliaries	240	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	2,140	kW_e
Total	**109,750**	**kW_e**
Plant Performance		
Net Auxiliary Load	109,750	kW_e
Net Plant Power	624,620	kW_e
Net Plant Efficiency (HHV)	42.0%	
Net Plant Heat Rate (HHV)	8,130	Btu/kWh
Coal Feed Flowrate	435,161	lb/hr
Thermal Input[1]	1,487,801	kW_t
Condenser Duty	1,399	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

Note: GT air extraction yields 23% air integration

5.4 Economic Results

The capital and operating costs estimate results for Case 4 are shown in Exhibit 34 through Exhibit 38. The Total Plant Cost with a dual gasifier train is estimated to be 1,519 $/kW and 1,674 $/kW for a plant with a redundant three gasifier train. At 94% and 90% capacity factors, the Levelized Cost of Electricity for the redundant train arrangements are 52.5 and 54.2 mills/kWh, respectively. At 85% capacity factor, the LCOE for the dual train arrangement is 52.8 mills/kWh.

Exhibit 34
Case 4 - Shell Gasifier-Based IGCC Total Plant Capital Costs with Dual Gasifier Train

Client: DEPARTMENT OF ENERGY **Report Date:** 20-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 4 Shell IGCC for Power Production
Plant Size: 624.62 MW,net **Estimate Type:** Conceptual **Cost Base (December)** 2004 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOT. PLANT COST $	TOT. PLANT COST $/kW
1	COAL HANDLING	9,964	1,901	8,316	582	**20,763**	2,076		3,083	**$25,922**	$42
2	COAL PREP & FEED	78,700	5,833	13,931	975	**99,440**	9,944		14,767	**$124,151**	$199
3	FEEDWATER & MISC. BOP SYSTEMS	6,941	6,256	7,369	516	**21,082**	2,108		3,131	**$26,321**	$42
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	83,340		41,009	2,871	**127,220**	12,722		18,892	**$158,834**	$254
4.2	Syngas Cooling	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	64,216		w/Equip		**64,216**	6,422		9,536	**$80,174**	$128
4.4-4.9	Other Gasification Equipment	35,531	5,502	10,974	768	**52,776**	5,278		7,837	**$65,891**	$105
	Subtotal 4	183,087	5,502	51,984	3,639	**244,212**	24,421		36,265	**$304,899**	$488
5	GAS & CLEANUP AND PIPING	23,655	2,630	15,774	1,104	**43,163**	4,316		6,410	**$53,889**	$86
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		17,776	**$149,449**	$239
6.2-6.9	Combustion Turbine Accessories		555	624	44	**1,223**	122		182	**$1,527**	$2
	Subtotal 6	115,259	555	4,777	334	**120,925**	12,093		17,957	**$150,975**	$242
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		5,181	**$43,558**	$70
7.2-7.9	SCR System, Ductwork and Stack	2,681	1,650	2,414	169	**6,914**	691		1,027	**$8,632**	$14
	Subtotal 7	33,221	1,650	6,478	453	**41,802**	4,180		6,208	**$52,190**	$84
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	30,783		3,763	263	**34,810**	3,481		5,169	**$43,460**	$70
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	7,411	682	5,875	411	**14,379**	1,438		2,135	**$17,952**	$29
	Subtotal 8	38,194	682	9,638	675	**49,189**	4,919		7,305	**$61,412**	$98
9	COOLING WATER SYSTEM	9,297	5,036	7,937	556	**22,825**	2,283		3,390	**$28,498**	$46
10	ASH/SPENT SORBENT HANDLING SYS	15,219	1,232	8,042	563	**25,056**	2,506		3,721	**$31,283**	$50
11	ACCESSORY ELECTRIC PLANT	14,218	6,335	16,077	1,125	**37,755**	3,775		5,607	**$47,137**	$75
12	INSTRUMENTATION & CONTROL	6,727	1,017	5,061	354	**13,159**	1,316		1,954	**$16,429**	$26
13	IMPROVEMENTS TO SITE	2,443	1,441	5,728	401	**10,013**	1,001		1,487	**$12,501**	$20
14	BUILDINGS & STRUCTURES		4,430	5,686	398	**10,514**	1,051		1,561	**$13,126**	$21
	TOTAL COST	**$536,925**	**$44,498**	**$166,799**	**$11,676**	**$759,898**	**$75,990**		**$112,845**	**$948,732**	**$1,519**

Exhibit 35
Case 4 - Shell Gasifier-Based IGCC Total Plant Capital Costs with Redundant Gasifier Train

Client: DEPARTMENT OF ENERGY — **Report Date:** 20-Jan-06
Project: Rocketdyne IGCC Power Plant

TOTAL PLANT COST SUMMARY

Case: Case 4 Shell IGCC for Power Production
Plant Size: 624.62 MW,net — **Estimate Type:** Conceptual — **Cost Base (December)** 2004 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL HANDLING	9,964	1,901	8,316	582	**20,763**	2,076		3,083	**$25,922**	$42
2	COAL PREP & FEED	78,700	5,833	13,931	975	**99,440**	9,944		14,767	**$124,151**	$199
3	FEEDWATER & MISC. BOP SYSTEMS	6,941	6,256	7,369	516	**21,082**	2,108		3,131	**$26,321**	$42
4	GASIFIER & ACCESSORIES										
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	125,000		60,000	4,200	**189,200**	18,920		28,096	**$236,216**	$378
4.2	Syngas Cooling	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	64,216		w/Equip		**64,216**	6,422		9,536	**$80,174**	$128
4.4-4.9	Other Gasification Equipment	45,563	5,502	16,056	1,124	**68,245**	6,825		10,134	**$85,204**	$136
	Subtotal 4	234,779	5,502	76,056	5,324	**321,661**	32,166		47,767	**$401,594**	$643
5	GAS & CLEANUP AND PIPING	23,655	2,630	15,774	1,104	**43,163**	4,316		6,410	**$53,889**	$86
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator	115,259		4,153	291	**119,703**	11,970		17,776	**$149,449**	$239
6.2-6.9	Combustion Turbine Accessories		555	624	44	**1,223**	122		182	**$1,527**	$2
	Subtotal 6	115,259	555	4,777	334	**120,925**	12,093		17,957	**$150,975**	$242
7	HRSG, DUCTING & STACK										
7.1	Heat Recover Stream Generator	30,540		4,064	284	**34,888**	3,489		5,181	**$43,558**	$70
7.2-7.9	SCR System, Ductwork and Stack	2,681	1,650	2,414	169	**6,914**	691		1,027	**$8,632**	$14
	Subtotal 7	33,221	1,650	6,478	453	**41,802**	4,180		6,208	**$52,190**	$84
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	30,783		3,763	263	**34,810**	3,481		5,169	**$43,460**	$70
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	7,411	682	5,875	411	**14,379**	1,438		2,135	**$17,952**	$29
	Subtotal 8	38,194	682	9,638	675	**49,189**	4,919		7,305	**$61,412**	$98
9	COOLING WATER SYSTEM	9,297	5,036	7,937	556	**22,825**	2,283		3,390	**$28,498**	$46
10	ASH/SPENT SORBENT HANDLING SYS	15,219	1,232	8,042	563	**25,056**	2,506		3,721	**$31,283**	$50
11	ACCESSORY ELECTRIC PLANT	14,218	6,335	16,077	1,125	**37,755**	3,775		5,607	**$47,137**	$75
12	INSTRUMENTATION & CONTROL	6,727	1,017	5,061	354	**13,159**	1,316		1,954	**$16,429**	$26
13	IMPROVEMENTS TO SITE	2,443	1,441	5,728	401	**10,013**	1,001		1,487	**$12,501**	$20
14	BUILDINGS & STRUCTURES		4,430	5,686	398	**10,514**	1,051		1,561	**$13,126**	$21
	TOTAL COST	**$588,617**	**$44,498**	**$190,871**	**$13,361**	**$837,347**	**$83,735**		**$124,346**	**$1,045,428**	**$1,674**

Exhibit 36
Case 4 - Shell Gasifier-Based IGCC Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION					1/20/2006
Case:	Case 4 Shell IGCC for Power Production				
Plant Size:		624.62 (MW,net)	Heat Rate	8,130	Btu/kWh
Fuel(type):		Illinois #6	Fuel Cost:	1.27	($/MMBtu)
Design/Construction:		3.5 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:		2004	TPI Year:	2004	(Jan.)
Capacity Factor:		94.0%	CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000	$/kW
Process Capital & Facilities			837,347	1,340.6
Engineering(incl.C.M.,H.O.& Fee)			83,735	134.1
Process Contingency			0	0.0
Project Contingency			124,346	199.1
	TOTAL PLANT COST(TPC)		1,045,428	1,673.7
	TOTAL CASH EXPENDED	$1,045,428		
	AFDC	78,193		
	TOTAL PLANT INVESTMENT(TPI)		1,123,621	1,798.9
Royalty Allowance			1,000	1.6
Preproduction Costs			28,536	45.7
Inventory Capital			7,600	12.2
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$1,161,312	1,859.2

OPERATING & MAINTENANCE COSTS(2004)		$x1000	$/kW-yr
Operating Labor		5,466	8.8
Maintenance Labor		11,873	19.0
Maintenance Material		22,502	36.0
Administrative & Support Labor		4,127	6.6
	TOTAL OPERATION & MAINTENANCE(2004)	$43,968	70.4
	FIXED O & M (2004)	$41,330	66.2
	VARIABLE O & M (2004)	$2,638	4.2

CONSUMABLE OPERATING COSTS, LESS FUEL(2004)		$x1000	¢/kWh
Water		4,637	0.09
Chemicals		6,697	0.13
Other Consumables		0	0.00
Waste Disposal		3,336	0.06
	TOTAL CONSUMABLES(2004)	$14,670	0.29
BY-PRODUCT CREDITS (2004)		($2,144)	(0.04)
FUEL COST(2004)		$53,086	1.03

PRODUCTION COST SUMMARY		2004 Costs ¢/kWh
Fixed O & M		0.80
Variable O & M		0.05
Consumables		0.29
By-product Credit		(0.04)
Fuel		1.03
	TOTAL PRODUCTION COST	2.13
2004 CARRYING CHARGES (Capital)		3.12
	FCR=0.138	
2004 BUSBAR COST OF POWER		5.25

Exhibit 37
Case 4 - Shell Gasifier-Based IGCC Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION					1/20/2006
Case:	Case 4 Shell IGCC for Power Production				
Plant Size:	624.62 (MW,net)		Heat Rate	8,130	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2004	(Jan.)
Capacity Factor:	90.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000	$/kW
Process Capital & Facilities			837,347	1,340.6
Engineering(incl.C.M.,H.O.& Fee)			83,735	134.1
Process Contingency			0	0.0
Project Contingency			124,346	199.1
	TOTAL PLANT COST(TPC)		1,045,428	1,673.7
	TOTAL CASH EXPENDED	$1,045,428		
	AFDC	78,193		
	TOTAL PLANT INVESTMENT(TPI)		1,123,621	1,798.9
Royalty Allowance			1,000	1.6
Preproduction Costs			28,483	45.6
Inventory Capital			7,360	11.8
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$1,161,019	1,858.8
OPERATING & MAINTENANCE COSTS(2004)			$x1000	$/kW-yr
Operating Labor			5,466	8.8
Maintenance Labor			11,873	19.0
Maintenance Material			22,502	36.0
Administrative & Support Labor			4,127	6.6
	TOTAL OPERATION & MAINTENANCE(2004)		$43,968	70.4
	FIXED O & M (2004)		$39,571	63.4
	VARIABLE O & M (2004)		$4,397	7.0
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			$x1000	¢/kWh
Water			4,440	0.09
Chemicals			6,412	0.13
Other Consumables			0	0.00
Waste Disposal			3,194	0.06
	TOTAL CONSUMABLES(2004)		$14,046	0.29
BY-PRODUCT CREDITS (2004)			($2,052)	(0.04)
FUEL COST(2004)			$50,827	1.03

		2004 Costs
PRODUCTION COST SUMMARY		¢/kWh
Fixed O & M		0.80
Variable O & M		0.09
Consumables		0.29
By-product Credit		(0.04)
Fuel		1.03
	TOTAL PRODUCTION COST	2.17
2004 CARRYING CHARGES (Capital)		3.25
	FCR=0.138	
2004 BUSBAR COST OF POWER		5.42

Exhibit 38
Case 4 - Shell Gasifier-Based IGCC Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					**1/20/2006**
Case:	**Case 4 Shell IGCC for Power Production**				
Plant Size:	**624.62 (MW,net)**		**Heat Rate**	**8,130**	**Btu/kWh**
Fuel(type):	**Illinois #6**		**Fuel Cost:**	**1.27**	**($/MMBtu)**
Design/Construction:	**3.5 (years)**		**BookLife:**	**20**	**(years)**
TPC(Plant Cost) Year:	**2004**		**TPI Year:**	**2004**	**(Jan.)**
Capacity Factor:	**85.0%**		**CO2 Removed**		**(TPD)**

CAPITAL INVESTMENT			**$x1000**		**$/kW**
Process Capital & Facilities			759,898		1,216.6
Engineering(incl.C.M.,H.O.& Fee)			75,990		121.7
Process Contingency			0		0.0
Project Contingency			112,845		180.7
	TOTAL PLANT COST(TPC)		948,732		1,518.9
	TOTAL CASH EXPENDED	$948,732			
	AFDC	70,960			
	TOTAL PLANT INVESTMENT(TPI)		1,019,693		1,632.5
Royalty Allowance			1,000		1.6
Preproduction Costs			26,075		41.7
Inventory Capital			7,060		11.3
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.9
	TOTAL CAPITAL REQUIREMENT(TCR)		$1,054,382		1,688.0
OPERATING & MAINTENANCE COSTS(2004)			**$x1000**		**$/kW-yr**
Operating Labor			5,466		8.8
Maintenance Labor			10,775		17.3
Maintenance Material			20,421		32.7
Administrative & Support Labor			4,127		6.6
	TOTAL OPERATION & MAINTENANCE(2004)		$40,789		65.3
	FIXED O & M (2004)		$34,670		55.5
	VARIABLE O & M (2004)		$6,118		9.8
CONSUMABLE OPERATING COSTS, LESS FUEL(2004)			**$x1000**		**¢/kWh**
Water			4,193		0.09
Chemicals			6,056		0.13
Other Consumables			0		0.00
Waste Disposal			3,017		0.06
	TOTAL CONSUMABLES(2004)		$13,266		0.29
BY-PRODUCT CREDITS (2004)			($1,938)		(0.04)
FUEL COST(2004)			$48,004		1.03
				2004 Costs	
PRODUCTION COST SUMMARY				**¢/kWh**	
Fixed O & M				0.75	
Variable O & M				0.13	
Consumables				0.29	
By-product Credit				(0.04)	
Fuel				1.03	
	TOTAL PRODUCTION COST			2.15	
2004 CARRYING CHARGES (Capital)				3.13	
	FCR=0.138				
2004 BUSBAR COST OF POWER				5.28	

6 CASE 5 - PWR GASIFIER BASED H_2 PRODUCTION PLANT DESCRIPTION AND RESULTS

Consuming 419,050 lb/hr of Illinois #6 coal, the PWR hydrogen production plant produces 56,179 lb/hr of 99.99%+ H_2. The plant requires an additional 31 MWe of power from another source to meet a total auxiliary load of 117 MWe.

A block flow diagram and associated stream tables for the Case 5 PWR gasifier-based H_2 production plant in partial quench mode are presented in Exhibit 39 and Exhibit 40, respectively.

6.1 Process Description

The Case 5 PWR H_2 production plant consists of two compact, partially quenched gasifiers each fed with approximately 1,800 tpd of 95% oxygen produced via an on site Air Separation Unit (ASU) and approximately 2,500 tpd of Illinois #6 coal dried from 11.12% to 5% in an AGR tail gas-fired coal dryer. It is assumed that Illinois #6 coal has 5% inherent moisture.

A proprietary PWR coal extrusion feed system is utilized for feeding dried coal to the PWR gasifier. Each train in the PWR process requires approximately 140 tpd of CO_2 as coal transport gas as well as approximately 390 tpd of steam injection.

The PWR process claims an adiabatic flame temperature of ~2500°F, 1,000 psig operating pressure, and 100% carbon conversion. Approximately 487 tpd of slag (100% ash) is removed from the gasification reaction products by using a partial quench to cool and then a candle filter to separate the slag.

In order to maximize H_2 production, the syngas is sent through a series of Water Gas Shift (WGS) reactors with intercooling to maximize overall conversion. Steam is injected into the syngas upstream of the WGS reactors to maintain a 1.1:1 molar ratio of water to dry gas at the inlet to the first reactor. Approximately 99% of the CO and a stoichiometric amount of H_2O in the syngas are converted to CO_2 and H_2. The shifted gas then goes through a series of gas coolers and cleanup processes including a carbon bed mercury removal system. A dual stage Selexol AGR treats the stream of synthesis gas to reduce the level of total sulfur (H_2S and COS) to no more than 30 ppm while concentrating the CO_2 for compression and capture. Carbon dioxide from the Selexol system is compressed to 2,200 psia for transport off site. COS hydrolysis is accomplished in the WGS reactors, eliminating the need for dedicated reactors to facilitate the reaction. Sour gas from the AGR plant is fed to a Claus plant, where elemental sulfur is recovered.

The cleaned H_2-rich stream from the Selexol unit is sent to a Pressure Swing Adsorption (PSA) system design to provide a concentrated H_2 product at 99.99%+ purity. Off-gas from the PSA is sent to a gas-fired waste heat boiler for combustion and subsequent steam generation. A portion of the steam generated is used to drive a non-reheat steam turbine for power generation, all of which is used to off-set the auxiliary power demand of the plant.

6.2 Modeling Assumptions for PWR Gasifier

Refer to Section 2.2 for a detailed discussion on the modeling assumptions used for PWR gasifier performance prediction in this study.

Exhibit 39
Case 5 - PWR H_2 Production Plant Block Flow Diagram

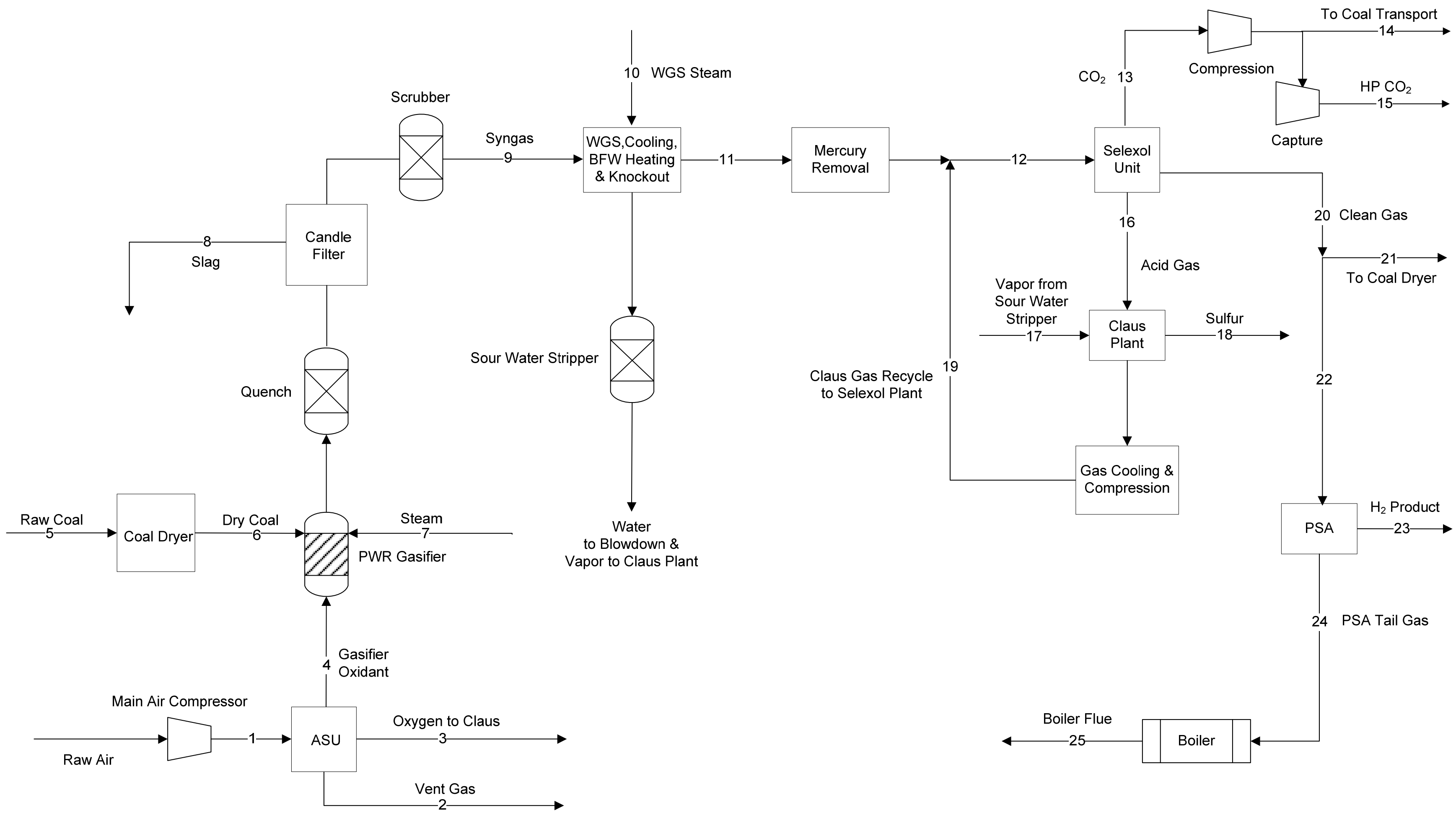

Exhibit 40
Case 5 - PWR H_2 Production Plant Stream Table

	1	2	3	4	5[A]	6[A]	7	8	10	13
V-L Mole Fraction										
Ar	0.0094	0.0036	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
CO_2	0.0003	0.0005	0.0000	0.0000	0.0000	0.3257	0.0000	0.0000	0.0000	0.9963
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020
H_2O	0.0104	0.0172	0.0000	0.0000	0.0000	0.6743	1.0000	0.0000	1.0000	0.0015
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.9786	0.0140	0.0500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	42,993	26,080	240	9,268	2,589	1,614	3,591	0	6,907	20,161
V-L Flowrate (lb/hr)	1,240,520	727,474	7,730	294,709	46,598	42,706	64,696	0	124,427	884,738
Solids Flowrate (lb/hr)	0	0	0	0	372,452	372,452	0	40,634	0	0
Temperature (°F)	271	55	90	800	59	195	800	500	600	58
Pressure (psia)	225.0	16.4	56.4	1,191.2	14.7	1,200.0	1,200.0	990.0	1,000.0	55.0
Enthalpy (Btu/lb)										
Density (lb/ft^3)	0.83	0.08	0.31	2.76	---	---	1.60	---	1.93	0.43
Molecular Weight	28.85	27.89	32.23	31.80	---	---	18.02	---	18.02	43.88

A - Solids flowrate includes coal; V-L flowrate includes water from coal (11.12 wt% moisture)
Note: Streams containing proprietary data are excluded from these stream tables

Exhibit 40 (continued)
Case 5 - PWR H2 Production Plant Stream Table

	14	15	16	17	18	19	20	21	22	23	24	25
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	0.0001	0.0000	0.0098	0.0002	0.0002	0.0002	0.0000	0.0009	0.0058
CH_4	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0015	0.0015	0.0015	0.0000	0.0058	0.0000
CO	0.0001	0.0001	0.0000	0.0124	0.0000	0.0121	0.0108	0.0108	0.0108	0.0000	0.0414	0.0000
CO_2	0.9963	0.9963	0.4941	0.3466	0.0000	0.5693	0.0586	0.0586	0.0586	0.0000	0.2253	0.0879
COS	0.0000	0.0000	0.0003	0.0004	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0020	0.0020	0.0000	0.0136	0.0000	0.1806	0.8810	0.8810	0.8810	1.0000	0.5421	0.0000
H_2O	0.0015	0.0015	0.0133	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0000	0.0002	0.1842
H_2S	0.0000	0.0000	0.4127	0.0404	0.0000	0.0366	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0001	0.0001	0.0795	0.0031	0.0000	0.1908	0.0479	0.0479	0.0479	0.0000	0.1843	0.7017
NH_3	0.0000	0.0000	0.0000	0.5831	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0204
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	527	19,634	851	331	41	880	37,777	120	37,656	27,866	9,790	30,419
V-L Flowrate (lb/hr)	23,126	861,612	32,577	8,965	0	28,837	227,864	725	227,139	56,179	170,960	843,488
Solids Flowrate (lb/hr)	0	0	0	0	10,478	0	0	0	0	0	0	0
Temperature (°F)	195	353	120	450	296	95	70	70	70	193	170	280
Pressure (psia)	1,194.2	2,900.0	71.0	113.5	51.0	767.5	678.0	678.0	678.0	668.0	67.8	14.5
Enthalpy (Btu/lb)												
Density (lb/ft^3)	7.46	14.59	0.44	0.32	---	4.22	0.72	0.72	0.72	0.19	0.18	0.05
Molecular Weight	43.88	43.88	38.30	27.06	---	32.76	6.03	6.03	6.03	2.02	17.46	27.73

6.3 Equipment Descriptions

Coal Preparation and Feed Systems

The coal as received contains 11.12 percent moisture, and must be dried to 5 percent or less moisture. The coal is simultaneously crushed and dried using an air-fed combustion of clean synthesis gas from the exit of the Selexol unit. Crushed and dried coal is delivered to a surge hopper with an approximate 2-hour capacity.

The coal is drawn from the surge hoppers and fed through a developmental proprietary dry coal feed pump system, which uses CO_2 to convey the coal to the gasifiers.

Air Separation Unit

The air separation plant is designed to produce a nominal output of 3,600 tons/day of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 92 tons/day, is used in the Claus plant. The air compressor is powered by an electric motor.

Gasifier

The PWR gasifier uses a plug-flow entrained reactor and a multi-port injection nozzle to increase the kinetics and conversion of the gasification reaction. The PWR gasification process gasifies dried coal with steam and 95% (by volume) oxygen at ~2500°F and 1,000 psia. The PWR process claims a 100% carbon conversion and faster kinetics allowing for a more compact gasifier design. The prototype reactor designed to process 3,000 tons of dried coal per day is anticipated to be 39 inches in diameter and 15 feet in length. The amount of dried coal processed in this study is approximately 5,000 tons per day.

Syngas Cooling

Hot syngas and molten solids from the reactor flow downward through a quench region where the syngas is cooled to ~500°F. The gas and solidified slag then flow through a cyclone and candle filter system for dry particulate removal, from which the recovered solids are let down to ambient pressure.

Syngas Scrubbing

The syngas enters the syngas scrubber and is directed downwards by a dip tube into a water sump at the bottom of the syngas scrubber. Most of the solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. From the overhead of the syngas scrubber, the syngas enters the low-temperature gas cooling section for further cooling.

The water removed from the syngas scrubber contains all the solids that were not removed in the quench gasifier water sump. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas scrubber. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating scrubbing water is pumped by the syngas scrubber circulating pumps to the quench gasifier.

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. These solids are in the form of glass, which is non-leaching and fully encapsulates any metals.

Water Gas Shift Reaction

The saturated syngas enters the WGS system fully saturated at 446°F. The raw-gas shift to produce H_2 requires 124,427 lb/hr of steam, fulfilling a vendor-specified steam to dry gas molar ratio of 1.1. Steam at 600°F and 1,000 psia is added to the syngas, bringing the stream temperature to ~460°F as it enters the WGS reactors. The water gas shift reaction is as follows:

$$CO + H_2O \rightarrow H_2 + CO_2$$

There are a total of three WGS reactors containing proprietary sulfur-tolerant catalyst. Each of these reactor stages is intercooled, bringing the stream temperature down to 450°F before entering the next WGS reactor. The WGS reaction is exothermic and increases the temperature of the syngas stream, though conversion is favored at lower temperatures. Lowering the temperature to 450°F before each stage results in a 98.6% overall conversion of CO.

The WGS reactors also hydrolyzes COS and converts HCN to NH_3, therefore, no dedicated COS hydrolysis reactor is required.

Low Temperature Gas Cooling

Before the raw fuel gas can be treated in the AGR process, it must be cooled to about 100°F. During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section.

Mercury Removal

Refer to Case 1 in section 2.3 for a description of the Mercury Removal system used in Case 5, since they are similar.

Acid Gas/CO_2 Removal

Case 5 utilizes a multi-stage Selexol process to remove sulfur with ~90% CO_2 capture. The Selexol process treats the stream of synthesis gas to reduce the level of total sulfur (H_2S and COS) to no more than 30 ppm prior to it being sent to the PSA, while concentrating the CO_2 for compression and capture. A recycle stream of acid gas from the sulfur recovery unit (SRU) is also treated. An acid gas stream that contains ~50 percent sulfur is produced.

High sulfur, shifted gas is sent to the first absorber, which is labeled the H_2S absorber. Here it contacts a "CO_2-loaded" solvent, which enters at the top of the tower. In the H_2S absorber, H_2S, COS, CO_2, and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent to the CO_2 absorber where the gas first contacts a "semi-lean" solvent in the middle stages of the absorber. In these stages of the CO_2 absorber, the large majority of the CO_2 is transferred from the gas phase to the liquid phase. Fully regenerated, lean solvent enters the upper stages of this CO_2 absorber, removing additional CO_2 from the gas stream. The gas then leaves the CO_2 absorber for treatment in the Pressure Swing Adsorption system to concentrate the H_2. The solvent from the CO_2 absorber is split and a portion is sent to the H_2S absorber as the "CO_2-loaded" solvent. The remaining portion of the solvent is passed through a series of flash drums which transfer the absorbed CO_2 from the liquid phase into the gas phase for compression. The remaining solvent is sent to the mid-stages of the CO_2 absorber as the "semi-lean" solvent to absorb the majority of gas phase CO_2.

The solvent stream from the H_2S absorber is termed rich solvent and is sent to the H_2S concentrator, where portions of the CO_2, CO, H_2, and other gases are stripped from the solvent. Nitrogen from the ASU is used as the stripping medium. A portion of the overhead gas is recycled back to the H_2S absorber for further treatment. The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is fully regenerated. All gases are transferred from the liquid phase to the gas phase in this stripper and sent to the Sulfur Recovery System (SRS). The Tail gas from the SRS is recycled back to the AGR unit and enters with the feed to the H_2S absorber.

Sour Water Stripper

Refer to Case 1 in section 2.3 for a description of the Sour Water Stripper used in Case 5, since they are similar.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by reacting approximately a third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 113 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stream in the gasifier section. Tail gas from the Claus unit, after hydrogenation, is recycled to the Selexol unit. The combination of Claus technology and tail gas recycle will result in an overall sulfur recovery exceeding 99 percent.

Pressure Swing Adsorption System

The H_2-rich gas from the Selexol unit enters multiple, parallel beds of proprietary adsorbent. These beds are used in a semi-batch adsorption/desorption sequence for continuous H_2 production. The H_2-rich stream is fed at high pressure (~680 psia) to force contaminant adsorption onto the beds. The H_2 does not adsorb as strongly as the contaminant compounds, thus, can exit the beds at concentrations in excess of 99.99% before the beds become saturated.

Desorption occurs by depressurizing the beds to ~70 psia and back-flushing them with H_2 product. This low pressure flush purges the contaminants consisting of CO, CO_2, N_2, and CH_4 from the bed in a stream of ~50% H_2. Overall H_2 recovery for the PSA system is 84%; however, the overall H_2 recovery of the plant is slightly less than 84% due to the fuel requirement for coal drying.

Boiler

Off-gas from the PSA unit is combusted with excess air in a waste heat boiler to provide heat for steam generation. A conventional natural gas-fired boiler must be retrofitted with syngas burners to provide stable combustion with low NOx generation.

Steam Turbine

A non-reheat steam turbine is used to expand the excess 1,200 psia/1000°F steam generated in the Waste Heat Boiler to approximately 2" Hga (the condenser backpressure dictated in the design basis). The power output of the steam turbine does not fully off-set the auxiliary power demand of the plant, which was a design decision made in the interest of maximizing the efficiency of H_2 production.

6.4 Performance Results

Consuming 419,050 lb/hr of Illinois #6 coal, the PWR hydrogen production plant produces 56,179 lb/hr of 99.99%+ H_2. The steam produced by the plant generates 86 MWe for use in the plant. The plant requires an additional 31 MWe for a total auxiliary load of 116 MW_e.

The performance results are summarized in Exhibit 41.

Exhibit 41
Case 5 - PWR H_2 Production Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Steam Turbine Power	85,855	kW_e
Total	**85,855**	**kW_e**
Auxiliary Load		
Coal Handling	540	kW_e
Coal Milling	1,100	kW_e
Slag Handling	330	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	53,500	kW_e
Oxygen Compressor	9,327	kW_e
CO_2 Compression	38,995	kW_e
Tail Gas Compression	2,417	kW_e
Boiler Air Compressor	381	kW_e
Quench Pumps	667	kW_e
Condensate Pump	230	kW_e
Scrubber Pumps	300	kW_e
WGS Makeup Pump	948	kW_e
Cooling Tower Fans	570	kW_e
Selexol Unit Auxiliaries	2,700	kW_e
Claus Plant Auxiliaries	200	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	260	kW_e
Total	**116,465**	**kW_e**
Plant Performance		
Net Plant Power	-30,610	kW_e
H_2 (99.99%) Production	56,179	lb/hr
Coal Feed Flowrate	419,050	lb/hr
Thermal Input[1]	1,432,718	kW_t
Condenser Duty	606	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

6.5 Economic Results

The capital and operating costs estimate results are shown in Exhibit 42 through Exhibit 45. The Total Plant Cost is estimated to be 700,000 \$/TPD H_2. At a 94%, 90% and 85% capacity factor, the Levelized Cost of Hydrogen is 730, 748 and 773 \$/Ton, respectively.

Exhibit 42
Case 5 - PWR H_2 Production Total Plant Capital Costs

Client: DEPARTMENT OF ENERGY **Report Date:** 27-Mar-06
Project: Rocketdyne Power Plant Studies

TOTAL PLANT COST SUMMARY

Case: Case 5 -Rocketdyne Gasifier, H2 Coprod, Sequest, Boiler
Plant Size: 674.15 H2 TPD **Estimate Type:** Conceptual **Cost Base (January)** 2005 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/TPDH2
1	COAL & SORBENT HANDLING	9,776	1,817	7,827	548	**19,968**	1,997		4,393	**$26,358**	$39
2	COAL PREP & FEED SYSTEMS	12,900	5,981	9,968	137	**28,986**	2,899		6,377	**$38,261**	$57
3	FEEDWATER & MISC. BOP SYSTEMS	1,836	1,378	1,984	139	**5,336**	534		1,376	**$7,246**	$11
4	GASIFIER & ACCESSORIES										
4.1	Gasification System	30,395	9,978	16,280	1,140	**57,793**	5,779		7,077	**$70,648**	$105
4.2	Other Gasifier	w/4.1									
4.3	ASU/Oxidant Compression	61,415		w/equip.		**61,415**	6,142		3,378	**$70,934**	$105
4.4-4.9	Other Gasification Equipment	w/4.1									
	Subtotal 4	91,810	9,978	16,280	1,140	**119,208**	11,921		10,454	**$141,583**	$210
5	GAS & CLEANUP AND PIPING	68,263	3,864	34,065	2,385	**108,576**	10,858		21,242	**$140,676**	$209
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator										
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	BOILER, DUCTING & STACK										
7.1	Gas-Fired Steam Boiler	2,698		719	50	**3,467**	347		572	**$4,386**	$7
7.2-7.9	SCR System, Ductwork and Stack	601	701	888	62	**2,251**	225		455	**$2,932**	$4
	Subtotal 7	3,298	701	1,607	113	**5,719**	572		1,027	**$7,318**	$11
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	6,816		914	64	**7,794**	779		857	**$9,431**	$14
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	1,859	162	1,396	98	**3,515**	352		671	**$4,538**	$7
	Subtotal 8	8,676	162	2,310	162	**11,309**	1,131		1,529	**$13,969**	$21
9	COOLING WATER SYSTEM	2,121	1,280	2,014	141	**5,557**	556		1,127	**$7,239**	$11
10	ASH/SPENT SORBENT HANDLING SYS	9,965	5,577	9,478	663	**25,684**	2,568		3,040	**$31,292**	$46
11	ACCESSORY ELECTRIC PLANT	6,998	3,152	7,813	547	**18,510**	1,851		3,452	**$23,813**	$35
12	INSTRUMENTATION & CONTROL	2,649	379	1,888	132	**5,048**	505		779	**$6,332**	$9
13	IMPROVEMENTS TO SITE	2,000	1,489	5,290	370	**9,150**	915		3,019	**$13,084**	$19
14	BUILDINGS & STRUCTURES		4,522	5,789	436	**10,748**	1,075		2,957	**$14,779**	$22
	TOTAL COST	**$220,292**	**$40,281**	**$106,313**	**$6,912**	**$373,798**	**$37,380**		**$60,772**	**$471,950**	**$700**

Exhibit 43
Case 5 - PWR H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION						3/27/2006
Case:	Case 5 -Rocketdyne Gasifier, H2 Coprod, Sequest, Boiler					
Plant Size:	Case 594	674.15 TPD H2		Heat Rate	N/A	Btu/kWh
Fuel(type):		Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:		3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:		2004		TPI Year:	2010	(Jan.)
Capacity Factor:		94.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000		$/TPD H2
Process Capital & Facilities			373,798		554.47
Engineering(incl.C.M.,H.O.& Fee)			37,380		55.45
Process Contingency			0		0.00
Project Contingency			60,772		90.15
	TOTAL PLANT COST(TPC)		471,950		700.07
	TOTAL CASH EXPENDED	$471,950			
	AFDC	35,299			
	TOTAL PLANT INVESTMENT(TPI)		507,249		752.43
Royalty Allowance			1,000		1.48
Preproduction Costs			14,121		20.95
Inventory Capital			6,550		9.72
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.82
	TOTAL CAPITAL REQUIREMENT(TCR)		$529,475		785.40
OPERATING & MAINTENANCE COSTS(2005)			$x1000		$/Ton
Operating Labor			4,625		20.00
Maintenance Labor			5,360		23.17
Maintenance Material			10,158		43.92
Administrative & Support Labor			3,492		15.10
	TOTAL OPERATION & MAINTENANCE(2005)		$23,636		102.19
	FIXED O & M (2005)		$22,218		96.06
	VARIABLE O & M (2005)		$1,418		6.13
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			$x1000		$/Ton
Water			2,852		12.33
Chemicals			5,111		22.10
Other Consumables			0		0.00
Waste Disposal			2,515		10.87
	TOTAL CONSUMABLES(2005)		$10,478		45.30
BY-PRODUCT CREDITS (2005)			($2,157)		-9.32
FUEL COST(2005)			$51,121		221.02
PURCHASED ELECTRICITY COST(2005)			$12,603		54.49
PRODUCTION COST SUMMARY (2005)				$/Ton	
Fixed O & M				$96.06	
Variable O & M				$6.13	
Consumables				$45.30	
By-product Credit				($9.32)	
Fuel				$221.02	
Purchased Electricity				$54.49	
	TOTAL PRODUCTION COST			$413.67	
2005 CARRYING CHARGES (Capital)				$315.90	
	FCR=0.138				
2005 COST OF HYDROGEN				$729.57	
			or $/kg	$0.80	

Exhibit 44
Case 5 - PWR H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION					3/27/2006
Case:	Case 5 -Rocketdyne Gasifier, H2 Coprod, Sequest, Boiler				
Plant Size:	Case 590	674.15 TPD H2	Heat Rate	N/A	Btu/kWh
Fuel(type):		Illinois #6	Fuel Cost:	1.27	($/MMBtu)
Design/Construction:		3.5 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:		2004	TPI Year:	2010	(Jan.)
Capacity Factor:		90.0%	CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000		$/TPD H2
Process Capital & Facilities			373,798		554.47
Engineering(incl.C.M.,H.O.& Fee)			37,380		55.45
Process Contingency			0		0.00
Project Contingency			60,772		90.15
	TOTAL PLANT COST(TPC)		471,950		700.07
	TOTAL CASH EXPENDED	$471,950			
	AFDC	35,299			
	TOTAL PLANT INVESTMENT(TPI)		507,249		752.43
Royalty Allowance			1,000		1.48
Preproduction Costs			14,084		20.89
Inventory Capital			6,331		9.39
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.82
	TOTAL CAPITAL REQUIREMENT(TCR)		$529,219		785.02
OPERATING & MAINTENANCE COSTS(2005)			$x1000		$/Ton
Operating Labor			4,625		20.89
Maintenance Labor			5,360		24.20
Maintenance Material			10,158		45.87
Administrative & Support Labor			3,492		15.77
	TOTAL OPERATION & MAINTENANCE(2005)		$23,636		106.73
	FIXED O & M (2005)		$21,272		96.06
	VARIABLE O & M (2005)		$2,364		10.67
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			$x1000		$/Ton
Water			2,730		12.33
Chemicals			4,894		22.10
Other Consumables			0		0.00
Waste Disposal			2,408		10.87
	TOTAL CONSUMABLES(2005)		$10,032		45.30
BY-PRODUCT CREDITS (2005)			($2,065)		-9.32
FUEL COST(2005)			$48,946		221.02
PURCHASED ELECTRICITY COST(2005)			$12,066		54.49
PRODUCTION COST SUMMARY (2005)				$/Ton	
Fixed O & M				$96.06	
Variable O & M				$10.67	
Consumables				$45.30	
By-product Credit				($9.32)	
Fuel				$221.02	
Purchased Electricity				$54.49	
	TOTAL PRODUCTION COST			$418.21	
2005 CARRYING CHARGES (Capital)				$329.78	
	FCR=0.138				
2005 COST OF HYDROGEN				$747.99	
			or $/kg	$0.82	

Exhibit 45
Case 5 - PWR H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					3/27/2006
Case:	Case 5 -Rocketdyne Gasifier, H2 Coprod, Sequest, Boiler				
Plant Size:	674.15 TPD H2		Heat Rate	N/A	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2010	(Jan.)
Capacity Factor:	85.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			**$x1000**	**$/TPD H2**
Process Capital & Facilities			373,798	554.47
Engineering(incl.C.M.,H.O.& Fee)			37,380	55.45
Process Contingency			0	0.00
Project Contingency			60,772	90.15
	TOTAL PLANT COST(TPC)		471,950	700.07
	TOTAL CASH EXPENDED	$471,950		
	AFDC	35,299		
	TOTAL PLANT INVESTMENT(TPI)		507,249	752.43
Royalty Allowance			1,000	1.48
Preproduction Costs			14,037	20.82
Inventory Capital			6,058	8.99
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.82
	TOTAL CAPITAL REQUIREMENT(TCR)		$528,900	784.55
OPERATING & MAINTENANCE COSTS(2005)			**$x1000**	**$/Ton**
Operating Labor			4,625	22.11
Maintenance Labor			5,360	25.63
Maintenance Material			10,158	48.57
Administrative & Support Labor			3,492	16.70
	TOTAL OPERATION & MAINTENANCE(2005)		$23,636	113.01
	FIXED O & M (2005)		$20,091	96.06
	VARIABLE O & M (2005)		$3,545	16.95
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			**$x1000**	**$/Ton**
Water			2,579	12.33
Chemicals			4,622	22.10
Other Consumables			0	0.00
Waste Disposal			2,274	10.87
	TOTAL CONSUMABLES(2005)		$9,475	45.30
BY-PRODUCT CREDITS (2005)			($1,950)	-9.32
FUEL COST(2005)			$46,226	221.02
PURCHASED ELECTRICITY COST(2005)			$11,396	54.49

PRODUCTION COST SUMMARY (2005)			**$/Ton**
Fixed O & M			$96.06
Variable O & M			$16.95
Consumables			$45.30
By-product Credit			($9.32)
Fuel			$221.02
Purchased Electricity			$54.49
	TOTAL PRODUCTION COST		$424.49
2005 CARRYING CHARGES (Capital)			$348.97
	FCR=0.138		
2005 COST OF HYDROGEN			$773.45
		or $/kg	$0.85

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7 CASE 6 - GE ENERGY GASIFIER BASED H_2 PRODUCTION PLANT DESCRIPTION AND RESULTS

Consuming 419,050 lb/hr of Illinois #6 coal, the GE Energy hydrogen production plant produces 50,322 lb/hr of 99.99%+ H_2. The plant requires an additional 50 MWe of power from another source to meet a total auxiliary load of 125 MWe.

A block flow diagram and associated stream tables for the Case 6 GE Energy gasifier-based H_2 production plant in quench mode are presented in Exhibit 46 and Exhibit 47, respectively.

7.1 Process Description

Case 6 is similar to Case 2 but the gasifier operates in a total quench mode rather than the radiant-quench mode, with the H_2 production similar to Case 5.

Exhibit 46
Case 6 - GE Energy H_2 Production Plant Block Flow Diagram

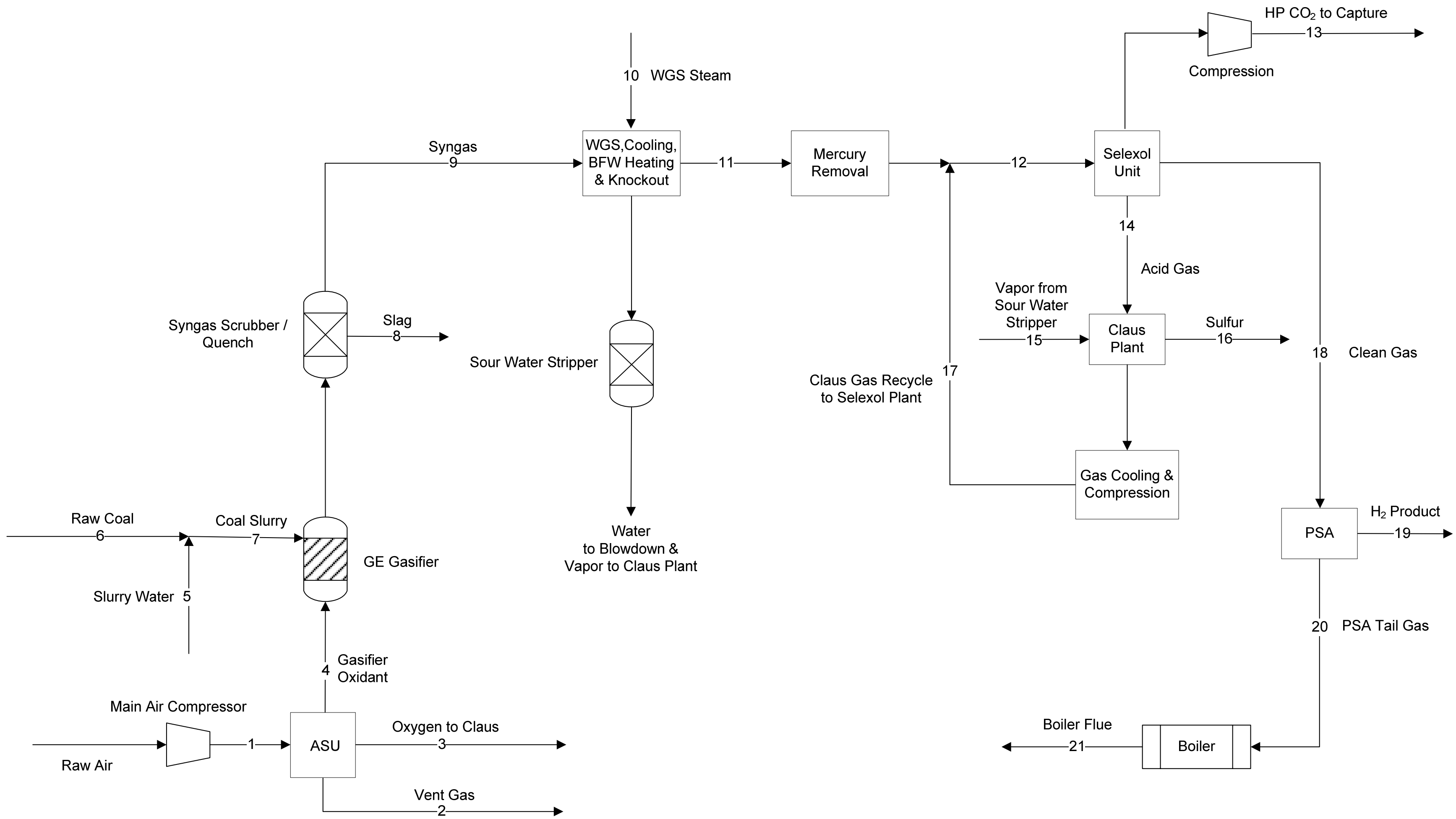

Exhibit 47
Case 6 - GE Energy H_2 Production Plant Stream Table

	1	2	3	4	5	6[A]	7[A]	8	10	13
V-L Mole Fraction										
Ar	0.0094	0.0034	0.0360	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
CO_2	0.0003	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.9965
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0018
H_2O	0.0104	0.0156	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0014
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7722	0.9804	0.0140	0.0180	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2077	0.0000	0.9500	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	50,677	33,735	178	10,900	9,556	2,589	12,152	0	8,499	19,477
V-L Flowrate (lb/hr)	1,462,260	941,410	5,729	350,770	172,146	46,598	218,744	0	153,103	854,918
Solids Flowrate (lb/hr)	0	0	0	0	0	372,452	372,452	45,998	0	0
Temperature (°F)	271	55	90	205	60	59	60	429	700	353
Pressure (psia)	225.0	16.4	56.4	1,025.0	1,050.0	14.7	1,050.0	804.7	1,000.0	2,900.0
Enthalpy (Btu/lb)										
Density (lb/ft^3)	0.83	0.08	0.31	4.62	62.58	---	---	---	1.66	14.60
Molecular Weight	28.85	27.91	32.23	32.18	18.02	---	---	---	18.02	43.89

A - Solids flowrate includes coal; V-L flowrate includes water from coal (11.12 wt% moisture)
Note: Streams containing proprietary data are excluded from these stream tables

Exhibit 47 (continued)
Case 6 - GE Energy H2 Production Plant

	14	15	16	17	18	19	20	21
V-L Mole Fraction								
Ar	0.0000	0.0021	0.0000	0.0093	0.0104	0.0000	0.0393	0.0190
CH_4	0.0000	0.0002	0.0000	0.0000	0.0008	0.0000	0.0031	0.0000
CO	0.0000	0.0044	0.0000	0.0088	0.0064	0.0000	0.0240	0.0000
CO_2	0.4848	0.5879	0.0000	0.6929	0.0630	0.0000	0.2378	0.0919
COS	0.0003	0.0001	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0268	0.0000	0.1027	0.8751	1.0000	0.5287	0.0000
H_2O	0.0123	0.0000	0.0000	0.0006	0.0000	0.0000	0.0002	0.1911
H_2S	0.4356	0.0486	0.0000	0.0643	0.0000	0.0000	0.0000	0.0000
N_2	0.0670	0.0011	0.0000	0.1210	0.0442	0.0000	0.1669	0.6785
NH_3	0.0000	0.3287	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0196
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	838	176	41	724	33,953	24,960	8,993	25,986
V-L Flowrate (lb/hr)	32,084	5,874	10,462	26,759	216,725	50,322	166,402	724,426
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	120	450	295	95	70	193	170	280
Pressure (psia)	71.0	113.5	51.0	767.5	678.0	668.0	67.8	14.5
Enthalpy (Btu/lb)								
Density (lb/ft^3)	0.44	0.39	---	5.77	0.76	0.19	0.19	0.05
Molecular Weight	38.30	33.43	---	36.94	6.38	2.02	18.50	27.88

7.2 Equipment Descriptions

Air Separation Unit

The air separation plant is designed to produce a nominal output of 4,300 tons/day of 95 percent pure O_2 from two ASU production trains. Most of the oxygen is used in the gasifier. A small portion, approximately 70 tons/day, is used in the Claus plant. The air compressor is powered by an electric motor.

Gasifier

This plant utilizes two gasification trains to process a total of 5,000 tons per day of coal. The slurry feed pump takes suction from the slurry run tank, and the discharge is sent to the feed injector of the GEE gasifier. Oxygen from the ASU is vented during preparation for startup and is sent to the feed injector during normal operation. The air separation plant supplies 2,100 tons of 95 percent purity oxygen per day to each gasifier.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel is located a combination fuel injector through which coal slurry feedstock and oxidant (oxygen) are fed. The coal slurry and the oxygen feeds react in the gasifier at about 815 psia at a high temperature (in excess of 2,400°F) to produce syngas.

The syngas consists primarily of hydrogen and carbon monoxide, with lesser amounts of water vapor and carbon dioxide, and small amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, and nitrogen. The heat in the gasifier liquefies coal ash.

Syngas Cooling

Hot syngas and molten solids from the reactor flow downward through a quench region where the syngas is cooled to ~430°F. The gas and solidified slag then flow into a water-filled quench chamber. The solids collect in the water sump at the bottom of the gasifier and are removed periodically, using a lock hopper system.

Solids collected in the quench gasifier water sump are removed by gravity and forced circulation of water from the lock hopper circulating pump. Fine material, which does not settle as easily, is removed in the gasification blowdown which is sent to the vacuum flash drum by way of the syngas scrubber.

Syngas Scrubbing

The syngas enters the syngas scrubber and is directed downwards by a dip tube into a water sump at the bottom of the syngas scrubber. Most of the solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. From the overhead of the syngas scrubber, the syngas enters the low-temperature gas cooling section for further cooling.

The water removed from the syngas scrubber contains all the solids that were not removed in the quench gasifier water sump. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas scrubber.

The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating scrubbing water is pumped by the syngas scrubber circulating pumps to the quench gasifier.

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. These solids are in the form of glass, which is non-leaching and fully encapsulates any metals.

Water Gas Shift (WGS) Reactors

The saturated syngas enters the WGS system fully saturated at ~430°F. The raw-gas shift to produce H_2 requires 153,103 lb/hr of steam, fulfilling a vendor-specified steam to dry gas ratio of 1.1. Steam at 700°F and 1,000 psia is added to the syngas, bringing the stream temperature to ~460°F as it enters the WGS reactors. The water gas shift reaction is as follows:

$$CO + H_2O \rightarrow H_2 + CO_2$$

There are a total of three WGS reactors containing proprietary sulfur-tolerant catalyst. Each of these reactor stages is intercooled, bringing the stream temperature down to 450°F before entering the next WGS reactor. The WGS reaction is exothermic and increases the temperature of the syngas stream, though conversion is favored at lower temperatures. Lowering the temperature to 450°F before each stage results in a 98.6% overall conversion of CO.

The WGS reactors also hydrolyzes COS and converts HCN to NH_3, therefore, no dedicated COS hydrolysis reactor is required.

Low Temperature Gas Cooling

Before the raw fuel gas can be treated in the AGR process, it must be cooled to about 100°F. During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section.

Mercury Removal

Refer to Case 1 in section 2.3 for a description of the Mercury Removal system used in Case 6, since they are similar.

Acid Gas/CO_2 Removal

Case 6 utilizes a multi-stage Selexol process to remove sulfur with ~90% CO_2 capture. The Selexol process treats the stream of synthesis gas to reduce the level of total sulfur (H_2S and COS) to no more than 30 ppm prior to it being sent to the PSA, while concentrating the CO_2 for compression and capture. A recycle stream of acid gas from the sulfur recovery unit (SRU) is also treated. An acid gas stream that contains ~50 percent sulfur is produced.

High sulfur, shifted gas is sent to the first absorber, which is labeled the H_2S absorber. Here it contacts a "CO_2-loaded" solvent, which enters at the top of the tower. In the H_2S absorber, H_2S, COS, CO_2, and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent to the CO_2 absorber where the gas first contacts a "semi-lean" solvent in the middle stages of the absorber. In these stages of the CO_2 absorber, the large majority of the CO_2 is transferred from the gas phase to the liquid phase. Fully regenerated, lean solvent enters the upper stages of this CO_2 absorber, removing additional

CO_2 from the gas stream. The gas then leaves the CO_2 absorber for treatment in the Pressure Swing Adsorption system to concentrate the H_2. The solvent from the CO_2 absorber is split and a portion is sent to the H_2S absorber as the "CO_2-loaded" solvent. The remaining portion of the solvent is passed through a series of flash drums which transfer the absorbed CO_2 from the liquid phase into the gas phase for compression. The remaining solvent is sent to the mid-stages of the CO_2 absorber as the "semi-lean" solvent to absorb the majority of gas phase CO_2.

The solvent stream from the H_2S absorber is termed rich solvent and is sent to the H_2S concentrator, where portions of the CO_2, CO, H_2, and other gases are stripped from the solvent. Nitrogen from the ASU is used as the stripping medium. A portion of the overhead gas is recycled back to the H_2S absorber for further treatment. The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is fully regenerated. All gases are transferred from the liquid phase to the gas phase in this stripper and sent to the Sulfur Recovery System (SRS). The Tail gas from the SRS is recycled back to the AGR unit and enters with the feed to the H_2S absorber.

Sour Water Stripper

Refer to Case 1 in section 2.3 for a description of the Sour Water Stripper used in Case 6, since they are similar.

Sulfur Recovery System

The sulfur recovery unit is a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by reacting approximately a third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant will produce approximately 113 long tons of elemental sulfur per day. Feed for this case consists of acid gas from both acid gas cleanup units and a vent stream from the sour water stream in the gasifier section. Tail gas from the Claus unit, after hydrogenation, is recycled to the Selexol unit. The combination of Claus technology and tail gas recycle will result in an overall sulfur recovery exceeding 99 percent.

Pressure Swing Adsorption System

The H_2-rich gas from the Selexol unit enters multiple, parallel beds of proprietary adsorbent. These beds are used in a semi-batch adsorption/desorption sequence for continuous H_2 production. The H_2-rich stream is fed at high pressure (~680 PSI) to force contaminant adsorption onto the beds. The H_2 does not adsorb as strongly as the contaminant compounds, thus, can exit the beds at concentrations in excess of 99.99% before the beds become saturated.

Desorption occurs by depressurizing the beds to ~70 PSI and back-flushing them with H_2 product. This low pressure flush purges the contaminants consisting of CO, CO_2, N_2, and CH_4 from the bed in a stream of ~50% H_2. Overall H_2 recovery for the PSA system is designed to be 84%.

Waste Heat Boiler

Off-gas from the PSA unit is combusted with excess air in a waste heat boiler to provide heat for steam generation. A conventional natural gas-fired boiler must be retrofitted with syngas burners to provide stable combustion with low NOx generation.

Steam Turbine

A non-reheat steam turbine is used to expand the excess 1,200 psia/1000°F steam generated in the Waste Heat Boiler to approximately 2" Hga (the condenser backpressure dictated in the design basis). The power output of the steam turbine does not fully off-set the auxiliary power demand of the plant, which was a design decision made in the interest of maximizing the efficiency of H_2 production.

7.3 Performance Results

Utilizing 419,050 lb/hr of Illinois #6 coal, the GE gasifier hydrogen plant produces 50,322 lb/hr of 99.99%+ H_2. The steam produced by the plant generates 75 MWe for internal use. The plant requires an additional 50 MWe to meet a total auxiliary load of 125MWe.

The performance results are summarized in Exhibit 48.

Exhibit 48
Case 6 - GE Energy H_2 Production Plant Performance Summary

POWER SUMMARY – 100 Percent Load (Gross Power at Generator Terminals, kWe		
Plant Output		
Steam Turbine Power	75,050	kW_e
Total	**75,050**	**kW_e**
Auxiliary Load		
Coal Handling	540	kW_e
Coal Milling	1,100	kW_e
Slag Handling	330	kW_e
Air Separation Unit Auxiliaries	1,000	kW_e
ASU Main Air Compressor	63,070	kW_e
Oxygen Compressor	10,150	kW_e
CO_2 Compression	38,100	kW_e
Tail Gas Compression	1,900	kW_e
Boiler Air Compressor	320	kW_e
Slurry Water Pump	240	kW_e
Quench Pumps	180	kW_e
Condensate Pump	230	kW_e
Scrubber Pumps	300	kW_e
WGS Makeup Pump	770	kW_e
Cooling Tower Fans	460	kW_e
Selexol Unit Auxiliaries	2,700	kW_e
Claus Plant Auxiliaries	200	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	230	kW_e
Total	**124,820**	**kW_e**
Plant Performance		
Net Plant Power	-49,770	kW_e
H_2 (99.99%) Production	50,322	lb/hr
Coal Feed Flowrate	419,050	lb/hr
Thermal Input[1]	1,432,718	kW_t
Condenser Duty	489	MMBtu/hr

1 - HHV of Illinois #6 11.12% Moisture Coal is 11,666 Btu/lb

7.4 Economic Results

The capital and operating costs estimate results for Case 6 are shown in Exhibit 49 through Exhibit 53. The Total Plant Cost with a dual gasifier train is estimated to be 920,000 \$/Ton H_2 and 982,000 \$/Ton H_2 for a plant with a redundant three gasifier train. At 94% and 90% capacity factors, the Levelized Cost of Hydrogen for the redundant train arrangements are 975 and 1,001 \$/Ton H_2, respectively. At 85% capacity factor, the LCOH for the dual train arrangement is 997 \$/Ton H_2.

Exhibit 49

Case 6 - GE Energy H_2 Production Total Plant Capital Costs with Dual Gasifier Train

Client: DEPARTMENT OF ENERGY | **Report Date:** 25-Mar-06

Project: Rocketdyne Power Plant Studies

TOTAL PLANT COST SUMMARY

Case: Case 6 -GE Gasifier, H2 Coprod, Sequest, Boiler

Plant Size: 603.86 H2 TPD | **Estimate Type:** Conceptual | **Cost Base (January)** 2005 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/TPDH2
1	COAL HANDLING	8,217	1,486	6,295	441	**16,438**	1,644		3,616	**$21,698**	$36
2	COAL PREP & FEED SYSTEMS	12,688	6,148	9,271	649	**28,756**	2,876		3,921	**$35,553**	$59
3	FEEDWATER & MISC. BOP SYSTEMS	2,555	1,917	2,760	193	**7,425**	743		1,915	**$10,083**	$17
4	GASIFIER & ACCESSORIES										
4.1	Quench Gasification System	30,915	9,985	17,923	1,255	**60,078**	6,008		6,609	**$72,694**	$120
4.2	Syngas Quench System (w/Gasifier-$)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	76,473		w/equip.		**76,473**	7,647		4,206	**$88,326**	$146
4.4-4.9	Other Gasification Equipment	15,372	15,498	18,076	1,265	**50,212**	5,021		6,218	**$61,450**	$102
	Subtotal 4	122,760	25,483	35,999	2,520	**186,763**	18,676		17,032	**$222,471**	$368
5	GAS & CLEANUP AND PIPING	66,123	3,800	33,919	2,374	**106,216**	10,622		20,710	**$137,548**	$228
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator										
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	BOILER, DUCTING & STACK										
7.1	Gas-Fired Steam Boiler	2,698		719	50	**3,467**	347		572	**$4,386**	$7
7.2-7.9	SCR System, Ductwork and Stack	601	701	888	62	**2,251**	225		455	**$2,932**	$5
	Subtotal 7	3,298	701	1,607	113	**5,719**	572		1,027	**$7,318**	$12
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	9,485		1,272	89	**10,845**	1,085		1,193	**$13,123**	$22
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	2,587	225	1,943	136	**4,891**	489		934	**$6,314**	$10
	Subtotal 8	12,072	225	3,214	225	**15,737**	1,574		2,127	**$19,437**	$32
9	COOLING WATER SYSTEM	2,952	1,781	2,803	196	**7,732**	773		1,568	**$10,073**	$17
10	ASH/SPENT SORBENT HANDLING SYS	11,119	6,223	10,575	740	**28,658**	2,866		3,392	**$34,916**	$58
11	ACCESSORY ELECTRIC PLANT	7,354	3,313	8,211	575	**19,453**	1,945		3,628	**$25,025**	$41
12	INSTRUMENTATION & CONTROL	2,783	399	1,984	139	**5,305**	530		819	**$6,654**	$11
13	IMPROVEMENTS TO SITE	2,000	1,489	5,290	370	**9,150**	915		3,019	**$13,084**	$22
14	BUILDINGS & STRUCTURES		3,618	4,385	433	**8,436**	844		2,321	**$11,601**	$19
	TOTAL COST	**$253,922**	**$56,582**	**$126,315**	**$8,968**	**$445,787**	**$44,579**		**$65,096**	**$555,461**	**$920**

Exhibit 50
Case 6 - GE Energy H_2 Production Total Plant Capital Costs with Redundant Gasifier Train

Client: DEPARTMENT OF ENERGY | **Report Date:** 25-Mar-06
Project: Rocketdyne Power Plant Studies

TOTAL PLANT COST SUMMARY

Case: Case 690 -GE Gasifier, H2 Coprod, Sequest, Boiler
Plant Size: 603.86 H2 TPD | **Estimate Type:** Conceptual | **Cost Base (January)** 2005 ; $x1000

Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O.& Fee	Process	Project	$	$/TPDH2
1	COAL & SORBENT HANDLING	8,217	1,486	6,295	441	**16,438**	1,644		3,616	**$21,698**	$36
2	COAL PREP & FEED SYSTEMS	12,688	6,148	9,271	649	**28,756**	2,876		3,921	**$35,553**	$59
3	FEEDWATER & MISC. BOP SYSTEMS	2,555	1,917	2,760	193	**7,425**	743		1,915	**$10,083**	$17
4	GASIFIER & ACCESSORIES										
4.1	Quench Gasification System	46,373	14,978	26,884	1,882	**90,117**	9,012		9,913	**$109,042**	$181
4.2	Syngas Scrubber System (w/Gasifier-$)	w/4.1		w/4.1							
4.3	ASU/Oxidant Compression	76,473		w/equip.		**76,473**	7,647		4,206	**$88,326**	$146
4.4-4.9	Other Gasification Equipment	15,372	15,962	18,386	1,287	**51,006**	5,101		6,392	**$62,499**	$103
	Subtotal 4	138,218	30,939	45,270	3,169	**217,596**	21,760		20,511	**$259,867**	$430
5	GAS & CLEANUP AND PIPING	66,123	3,800	33,919	2,374	**106,216**	10,622		20,710	**$137,548**	$228
6	COMBUSTION TURBINE/ACCESSORIES										
6.1	Combustion Turbine Generator										
6.2-6.9	Combustion Turbine Accessories										
	Subtotal 6										
7	BOILER, DUCTING & STACK										
7.1	Gas-Fired Steam Boiler	2,698		719	50	**3,467**	347		572	**$4,386**	$7
7.2-7.9	SCR System, Ductwork and Stack	601	701	888	62	**2,251**	225		455	**$2,932**	$5
	Subtotal 7	3,298	701	1,607	113	**5,719**	572		1,027	**$7,318**	$12
8	STEAM TURBINE GENERATOR										
8.1	Steam TG & Accessories	9,485		1,272	89	**10,845**	1,085		1,193	**$13,123**	$22
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	2,587	225	1,943	136	**4,891**	489		934	**$6,314**	$10
	Subtotal 8	12,072	225	3,214	225	**15,737**	1,574		2,127	**$19,437**	$32
9	COOLING WATER SYSTEM	2,952	1,781	2,803	196	**7,732**	773		1,568	**$10,073**	$17
10	ASH/SPENT SORBENT HANDLING SYS	11,119	6,223	10,575	740	**28,658**	2,866		3,392	**$34,916**	$58
11	ACCESSORY ELECTRIC PLANT	7,354	3,313	8,211	575	**19,453**	1,945		3,628	**$25,025**	$41
12	INSTRUMENTATION & CONTROL	2,783	399	1,984	139	**5,305**	530		819	**$6,654**	$11
13	IMPROVEMENTS TO SITE	2,000	1,489	5,290	370	**9,150**	915		3,019	**$13,084**	$22
14	BUILDINGS & STRUCTURES		3,618	4,385	433	**8,436**	844		2,321	**$11,601**	$19
	TOTAL COST	**$269,379**	**$62,038**	**$135,586**	**$9,617**	**$476,621**	**$47,662**		**$68,575**	**$592,858**	**$982**

Exhibit 51
Case 6 - GE Energy H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (94% Capacity factor)

TITLE/DEFINITION					3/27/2006
Case:	Case 694 -GE Gasifier, H2 Coprod, Sequest, Boiler				
Plant Size:	603.86 TPD H2		Heat Rate	N/A	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2010	(Jan.)
Capacity Factor:	94.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000	$/TPD H2
Process Capital & Facilities			476,621	789.28
Engineering(incl.C.M.,H.O.& Fee)			47,662	78.93
Process Contingency			0	0.00
Project Contingency			68,575	113.56
	TOTAL PLANT COST(TPC)		592,858	981.77
	TOTAL CASH EXPENDED	$592,858		
	AFDC	44,343		
	TOTAL PLANT INVESTMENT(TPI)		637,200	1,055.21
Royalty Allowance			1,000	1.66
Preproduction Costs			17,113	28.34
Inventory Capital			6,612	10.95
Initial Catalyst & Chemicals(w/equip.)				
Land Cost			555	0.92
	TOTAL CAPITAL REQUIREMENT(TCR)		$662,480	1,097.07
OPERATING & MAINTENANCE COSTS(2005)			$x1000	$/Ton H2
Operating Labor			4,625	22.32
Maintenance Labor			6,734	32.50
Maintenance Material			12,760	61.59
Administrative & Support Labor			3,492	16.86
	TOTAL OPERATION & MAINTENANCE(2005)		$27,612	133.27
	FIXED O & M (2005)		$25,955	125.27
	VARIABLE O & M (2005)		$1,657	8.00
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			$x1000	$/Ton H2
Water			3,020	14.57
Chemicals			5,320	25.68
Other Consumables			0	0.00
Waste Disposal			2,882	13.91
	TOTAL CONSUMABLES(2005)		$11,221	54.16
BY-PRODUCT CREDITS (2005)			($2,154)	(10.40)
FUEL COST(2005)			$51,121	246.74
PURCHASED ELECTRICITY COST(2005)			$22,848	110.28

PRODUCTION COST SUMMARY (2005)			$/Ton H2
Fixed O & M			125.27
Variable O & M			8.00
Consumables			54.16
By-product Credit			(10.40)
Fuel			246.74
Purchased Electricity			110.28
	TOTAL PRODUCTION COST		534.05
2005 CARRYING CHARGES (Capital)			441.26
	FCR=0.138		
2005 COST OF HYDROGEN			975.31
		or $/kg	$1.07

Exhibit 52
Case 6 - GE Energy H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (90% Capacity factor)

TITLE/DEFINITION					3/27/2006
Case:	Case 690 -GE Gasifier, H2 Coprod, Sequest, Boiler				
Plant Size:	603.86 TPD H2		Heat Rate		N/A Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:		1.27 ($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:		20 (years)
TPC(Plant Cost) Year:	2004		TPI Year:		2010 (Jan.)
Capacity Factor:	90.0%		CO2 Removed		(TPD)
CAPITAL INVESTMENT			$x1000		$/TPD H2
Process Capital & Facilities			476,621		789.28
Engineering(incl.C.M.,H.O.& Fee)			47,662		78.93
Process Contingency			0		0.00
Project Contingency			68,575		113.56
	TOTAL PLANT COST(TPC)		592,858		981.77
	TOTAL CASH EXPENDED	$592,858			
	AFDC	44,343			
	TOTAL PLANT INVESTMENT(TPI)		637,200		1,055.21
Royalty Allowance			1,000		1.66
Preproduction Costs			17,073		28.27
Inventory Capital			6,391		10.58
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.92
	TOTAL CAPITAL REQUIREMENT(TCR)		$662,219		1,096.64
OPERATING & MAINTENANCE COSTS(2005)			$x1000		$/Ton H2
Operating Labor			4,625		23.32
Maintenance Labor			6,734		33.94
Maintenance Material			12,760		64.33
Administrative & Support Labor			3,492		17.61
	TOTAL OPERATION & MAINTENANCE(2005)		$27,612		139.19
	FIXED O & M (2005)		$24,850		125.27
	VARIABLE O & M (2005)		$2,761		13.92
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			$x1000		$/Ton H2
Water			2,891		14.57
Chemicals			5,093		25.68
Other Consumables			0		0.00
Waste Disposal			2,759		13.91
	TOTAL CONSUMABLES(2005)		$10,743		54.16
BY-PRODUCT CREDITS (2005)			($2,062)		(10.40)
FUEL COST(2005)			$48,946		246.74
PURCHASED ELECTRICITY COST(2005)			$21,876		110.28
PRODUCTION COST SUMMARY (2005)				$/Ton H2	
Fixed O & M				125.27	
Variable O & M				13.92	
Consumables				54.16	
By-product Credit				(10.40)	
Fuel				246.74	
Purchased Electricity				110.28	
	TOTAL PRODUCTION COST			539.97	
2005 CARRYING CHARGES (Capital)				460.69	
	FCR=0.138				
2005 COST OF HYDROGEN				1,000.66	
			or $/kg	$1.10	

Exhibit 53
Case 6 - GE Energy H_2 Production Plant Capital Investment & Operating Cost Requirement Summary (85% Capacity factor)

TITLE/DEFINITION					3/27/2006
Case:	Case 6 -GE Gasifier, H2 Coprod, Sequest, Boiler				
Plant Size:	603.86 TPD H2		Heat Rate	N/A	Btu/kWh
Fuel(type):	Illinois #6		Fuel Cost:	1.27	($/MMBtu)
Design/Construction:	3.5 (years)		BookLife:	20	(years)
TPC(Plant Cost) Year:	2004		TPI Year:	2010	(Jan.)
Capacity Factor:	85.0%		CO2 Removed		(TPD)

CAPITAL INVESTMENT			$x1000		$/TPD H2
Process Capital & Facilities			445,787		738.22
Engineering(incl.C.M.,H.O.& Fee)			44,579		73.82
Process Contingency			0		0.00
Project Contingency			65,096		107.80
	TOTAL PLANT COST(TPC)		555,461		919.85
	TOTAL CASH EXPENDED	$555,461			
	AFDC	41,546			
	TOTAL PLANT INVESTMENT(TPI)		597,007		988.64
Royalty Allowance			1,000		1.66
Preproduction Costs			16,084		26.63
Inventory Capital			6,081		10.07
Initial Catalyst & Chemicals(w/equip.)					
Land Cost			555		0.92
	TOTAL CAPITAL REQUIREMENT(TCR)		$620,727		1,027.92
OPERATING & MAINTENANCE COSTS(2005)			$x1000		$/Ton H2
Operating Labor			4,625		24.69
Maintenance Labor			6,309		33.67
Maintenance Material			11,955		63.81
Administrative & Support Labor			3,492		18.64
	TOTAL OPERATION & MAINTENANCE(2005)		$26,382		140.82
	FIXED O & M (2005)		$22,425		119.70
	VARIABLE O & M (2005)		$3,957		21.12
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)			$x1000		$/Ton H2
Water			2,579		13.76
Chemicals			4,559		24.34
Other Consumables			0		0.00
Waste Disposal			2,606		13.91
	TOTAL CONSUMABLES(2005)		$9,744		52.01
BY-PRODUCT CREDITS (2005)			($1,948)		(10.40)
FUEL COST(2005)			$46,226		246.74
PURCHASED ELECTRICITY COST(2005)			$20,660		110.28
PRODUCTION COST SUMMARY (2005)				$/Ton H2	
Fixed O & M				119.70	
Variable O & M				21.12	
Consumables				52.01	
By-product Credit				(10.40)	
Fuel				246.74	
Purchased Electricity				110.28	
	TOTAL PRODUCTION COST			539.45	
2005 CARRYING CHARGES (Capital)				457.22	
	FCR=0.138				
2005 COST OF HYDROGEN				996.67	
			or $/kg	$1.10	

8 SUMMARY

This report compares six gasifier-based plant configurations. The results for each case are summarized in Exhibit 54. All results should be considered preliminary and dictated in large part by the selected design basis. It should also be noted that gasifier performance and cost data for the PWR gasifier was provided by the vendor and that RDS did not apply Process Contingency costs to the data provided. Since the design is conceptual and there has not yet been pilot plant or commercial operation, the performance and cost of the PWR gasifier should be considered preliminary.

Cases 1 and 2 reflect IGCC plants using either a PWR or a GE Energy gasifier respectively in both radiant quench heat recovery mode and similar plant configurations. Case 1 (PWR) shows a 3% net plant efficiency improvement over Case 2 (GE). In addition to the efficiency improvement, Case 1 costs more than $130 million less ($147/kWe) and shows an 8% reduction in the levelized cost of electricity on a common capacity factor. The difference is directly attributable to reduction in gasifier costs, reduction in thermal input to the plant, increased gasifier efficiency (resulting in lower oxygen requirements) and a fairly significant increase in plant availability without a spare gasifier.

Cases 3 and 4 compare PWR and Shell gasifiers in syngas quench/convective heat exchange mode. These cases exhibit more similar plant performance than PWR and GE since both gasifiers are dry coal-fed whereas the GE Energy gasifier in Case 2 is a slurry-fed gasifier (which is inherently less efficient). The net plant efficiency for the PWR gasifier plant is 0.9% higher than the comparable Shell gasification plant. In addition, there is a projected $205 million ($308/kWe) reduction in total plant cost for the PWR IGCC plant, which correlates to a 15% and 20% reduction in the levelized cost of electricity for a capacity factor of 85% and 94%, respectively. This is primarily attributable to a $94 million reduction in gasifier island costs associated with a less expensive PWR gasifier/syngas cooler arrangement but also attributable to a $66 million reduction in coal handling, preparation, and feed costs associated with using a dry coal feed pump instead of a dry coal lockhopper system. The application of a dry feed pump to the Shell gasifier can have similar cost benefits. A prior study has indicated that a capital cost reduction of about $100/kW can be taken from the feed system.[10]

Cases 5 and 6 compare the H_2 production capabilities of comparably sized (by thermal input) gasification plants based on the PWR and GE Energy gasifiers, respectively. The H_2 production of the Case 5 plant was 56,179 lb/hr while the Case 6 plant produced 50,322 lb/hr. This is partially attributable to the improved carbon conversion of the PWR gasifier and the fact that the PWR gasifier is dry coal-fed, both of which allow for increased availability of CO in the syngas that can be shifted in the WGS reactors, yielding increased amounts of H_2 as a result. The steam turbine power output of the PWR case is greater than that of the GE Energy case due to the reduced steam demand of the PWR WGS system and due to the increased CO in the saturated syngas which generates more recoverable WGS reaction heat. Case 5 costs more than $83 million less and shows a 23% reduction in the levelized cost of hydrogen on a common capacity factor.

The following overall conclusions can be reached from this study:

- Based on current expectations, the PWR gasifier system presents conversion efficiencies which are significantly higher than conventional gasifiers. However, future pilot studies must be performed to verify these expectations.
- Based on inclusion of PWR-PWR estimates, the capital and operating costs of the PWR gasifier plant are significantly lower than for conventional gasifiers.
- The PWR gasifier system can offer significantly lower production costs for both power and hydrogen relative to conventional gasifier systems.

Exhibit 54
Performance Summary and Economic Analysis Results

	Case 1 PWR Radiant Quench	**Case 2** GE Energy Radiant Quench	**Case 3** PWR Convective	**Case 4** Shell Convective	**Case 5** PWR H_2 Plant	**Case 6** GE Energy H_2 Plant
Performance						
Gas Turbine Power, MW_e	464.0	464.0	464.0	464.0	None	None
Sweet Gas Expander, MW_e	11.8	11.9	10.9	None	None	None
Steam Turbine Power, MW_e	230.7	282.2	239.9	270.4	85.9	75.0
Gross Power Output, MW_e	706.5	758.1	714.8	734.4	85.9	75.0
Auxiliary Power Load, MW_e	101.3	123.2	101.1	109.8	116.5	124.8
Net Power Output, MW_e	605.2	634.8	613.7	624.6	(30.6)	(49.8)
Net Plant Efficiency (HHV)	42.2%	39.2%	42.9%	42.0%	68.1%	59.4%
Net Plant Heat Rate, Btu/kWh HHV	8,078	8,699	7,957	8,130	N/A	N/A
Thermal Input, MW_t	1,433	1,619	1,431	1,488	1,433	1,433
Consumables/Products						
Coal Feed Flowrate, lb/hr	419,045	473,379	418,574	435,161	419,050	419,050
Gasifier Oxidant (95% O_2), lb/hr	294,706	396,246	294,374	337,137	294,709	350,770
Hydrogen Product, lb/hr	None	None	None	None	56,179	50,322
Sulfur Product, lb/hr	10,452	11,839	10,414	10,891	10,478	10,462
Economics						
85% Capacity Factor						
Total Plant Cost, $x1000	838,323	972,345	743,294	948,732	471,950	555,461
Total Plant Cost, $/kW	1,385	1,532	1,211	1,519	N/A	N/A
LCOE, mills/kWh	48.9	53.4	44.6	52.8	$0.85/kg	$1.10/kg
90% Capacity Factor						
Total Plant Cost, $x1000	838,323	1,057,235	743,294	1,045,428	471,950	592,858
Total Plant Cost, $/kW	1,385	1,665	1,211	1,674	N/A	N/A
LCOE, mills/kWh	46.9	54.3	42.8	54.2	$0.82/kg	$1.10/kg
94% Capacity Factor						
Total Plant Cost, $x1000	838,323	1,057,235	743,294	1,045,428	471,950	592,858
Total Plant Cost, $/kW	1,385	1,665	1,211	1,674	N/A	N/A
LCOE, mills/kWh	45.4	52.5	41.5	52.5	$0.80/kg	$1.07/kg

A – Total Plant Costs for Cases 2, 4 and 6 at 90% and 94% CF in this table include spare gasification trains
B – LCOE is Levelized Cost of Electricity. Costs for a spare gasifier were added to Cases 2 and 4 for 94% CF data.
C – Case 5 & 6 show Total Plant Cost of Hydrogen in $/kg of H_2/day and Levelized Cost of Hydrogen in $/kg H_2.

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