Coal Integrated Gasification Fuel Cell System Study

Final Report

April 2003 to January 2004

Chellappa Balan

Debashis Dey

Sukru-Alper Eker

Max Peter

Pavel Sokolov

Greg Wotzak

January 2004

Performed under DOE/NETL Cooperative Agreement

DE-FC26-01NT40779

Hybrid Power Generations Systems, LLC

19310 Pacific Gateway Drive

Torrance, CA 90502

DISCLAIMER

ACKNOWLEDGEMENTS

This material is based upon work supported by the U.S. Department of Energy under Award No DE-FC26-01NT40779. The authors wish to acknowledge the guidance of Dr. Nguyen Minh, Dr. Rajiv Doshi, Joe Ferrall, Faress Rahman (GE Hybrid Power Generation Systems), Dr. Ken Browall, Lou Schick, Stephane Renou (GE Global Research), David DeAngelis, Richard DePuy, Mike Jandrisetvits, Ray Andrews (GE Power Systems) and the DOE program manger.

ABSTRACT

This study analyzes the performance and economics of power generation systems based on Solid Oxide Fuel Cell (SOFC) technology and fueled by gasified coal. System concepts that integrate a coal gasifier with a SOFC, a gas turbine, and a steam turbine were developed and analyzed for plant sizes in excess of 200 MW. Two alternative integration configurations were selected with projected system efficiency of over 53% on a HHV basis, or about 10 percentage points higher than that of the state-of-the-art Integrated Gasification Combined Cycle (IGCC) systems. The initial cost of both selected configurations was found to be comparable with the IGCC system costs at approximately \$1700/kW. An absorption-based CO_2 isolation scheme was developed, and its penalty on the system performance and cost was estimated to be less approximately 2.7% and \$370/kW. Technology gaps and required engineering development efforts were identified and evaluated.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

Coal is the most abundant of all fossil fuels, and power generation in the United States relies heavily on coal. As seen in Figure 1, 51% of the total power generated in 2001 came from coal. In the next 20 years, coal is expected to remain the primary fuel source for power generation, although its share of total generation declines as natural gas increases its share (U.S. DOE/EIA, "Annual Energy Outlook 2000").

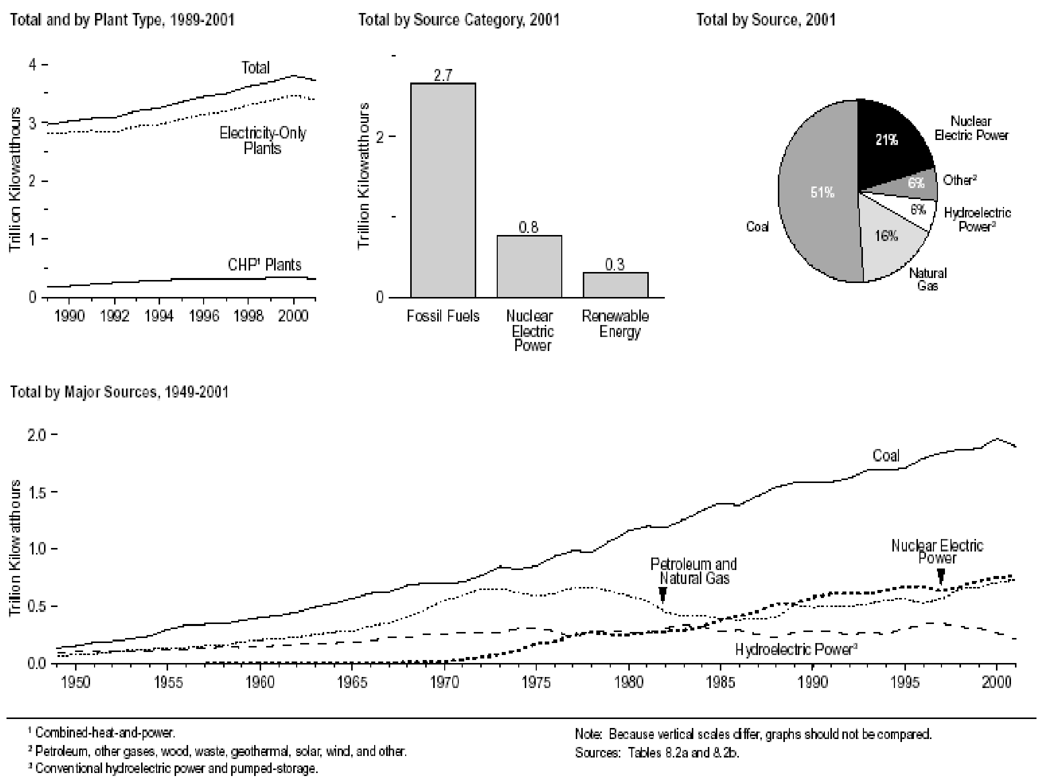

Figure 1. 2001 U.S. Electric Generation by Fuel Type

Source: U.S. DOE/EIA "Annual Energy Review 2001"

As concern about the environment generates interest in clean energy, fuel cell power plants can respond to the challenge. Fuel cells convert hydrocarbon fuels to electricity at efficiencies exceeding conventional heat engine technologies, while generating lower emissions. Emissions of SO_x and NO_x are expected to be well below current and anticipated future standards. Nitrogen oxides products of combustion are expected to be extremely low in this power plant because power is produced electrochemically rather than by combustion. Fuel cell power plants also produce less carbon dioxide. Fuel cells in combination with coal gasification are an efficient and environmentally acceptable means of using the abundant coal reserves both in the United States and around the world (Seinfeld et al.).

1.1 Background

A fundamental part of gasification-based systems is the coal gasifier. A gasifier converts hydrocarbon feedstock into gaseous components by applying heat under pressure in the presence of steam, which is used to produce electricity as depicted in Figure2.

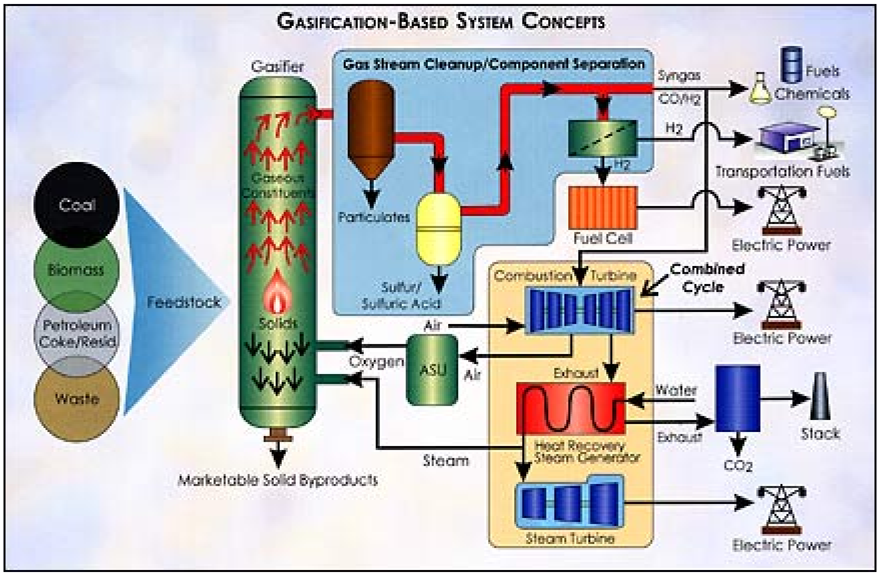

Figure 2. Gasification-based System Concept

Source: U.S. DOE Office of Fossil Energy

The amount of air or oxygen available inside the gasifier is carefully controlled so that only a relatively small portion of the fuel burns completely. This "partial oxidation" process provides the energy for the chemical reactions to take place. Rather than burning, most of the carbon-containing feedstock is chemically broken apart by the gasifier's heat and pressure. Chemical reactions taking place in the gasifier produce so-called syngas, which consists primarily of hydrogen, carbon monoxide, and other gaseous constituents, the proportions of which vary depending on the conditions in the gasifier and the type of feedstock. The gasification reactions are typically endothermic, with the required heat supplied by the combustion process of the remaining carbon-containing feedstock.

Sulfur impurities in the feedstock form hydrogen sulfide, from which sulfur is easily extracted, typically as elemental sulfur or sulfuric acid, both valuable by-products. Nitrogen oxides and other potential pollutants, are not formed in the oxygen-deficient (reducing) environment of the gasifier. Instead, ammonia is created by nitrogen-hydrogen reactions. The ammonia can easily be stripped out of the gas stream.

In Integrated Gasification Combined Cycle (IGCC) systems, the syngas is cleaned of its hydrogen sulfide, ammonia, and particulate matter and burned as fuel in a combustion turbine. The combustion turbine drives an electric generator. Hot air from the combustion turbine is channeled back to the air separation unit (ASU), while exhaust heat from the combustion turbine is recovered and used to create steam in a Heat Recovery Steam Generator (HRSG) for a steam turbine-generator.

The use of these two types of turbines—a combustion turbine and a steam turbine—in combination, known as a combined cycle, is one reason why gasification-based power systems can achieve relatively high power generation efficiencies. Higher efficiencies or lower heat rates mean that less fuel is used to generate the rated power, resulting in better economics (which can mean lower costs to ratepayers) and the formation of less greenhouse gas per unit of produced power. A 60%-efficient gasification power plant could cut the formation of carbon dioxide by 40% compared to a typical coal combustion plant.

All or part of the clean syngas can also be used in other ways:

- As chemical "building blocks" to produce a broad range of liquid or gaseous fuels and chemicals (using processes well established in today's chemical industry);
- As a source of hydrogen that can be separated from the gas stream and used as a fuel or as a feedstock for refineries (which use the hydrogen to upgrade petroleum products);
- As a fuel producer for highly efficient fuel cells that operate on the hydrogen generated in a gasifier or, in the future, fuel cell-turbine hybrid systems of the kind that is the subject of this program.

Another advantage of gasification-based energy systems is that when oxygen is used in the gasifier (rather than air), the carbon dioxide produced by the process is in a concentrated gas stream, making it much easier and less expensive to separate and capture. Once the carbon dioxide is captured, it can be sequestered—that is, prevented from escaping to the atmosphere and potentially contributing to the "greenhouse effect."

1.2 Program Objectives

Integrated Gasification Fuel Cell (IGFC) systems using top-level parametric assessment combined with technical judgment on what was achievable with technology advancement. Various component conceptual designs and cycle configurations were addressed in selecting the systems for analysis. Two down-selected configurations were assessed for impact on system complexity, performance, and estimated costs. The best configuration were selected and, for the selected system:

- The impact of carbon dioxide (CO_2) segregation (but not including eventual sequestration) was assessed.
- The impact of fuel cell fuel gas recycle was assessed.
- A rough order of magnitude (ROM) capital cost assessment was made for the identified configurations.

1.3 Prior and related work

Past studies indicated that using conventional gasification and clean-up technologies at a 200-MW scale, can achieve 43.6 % HHV efficiency with IGCC using British Gasification Lurgi (BGL) gasification and low temperature clean-up (Farooque et al., 1990; Sander et al., 1992; and Sandler and Meyers, 1992). Later studies indicated that higher efficiencies can be achieved with higher methane producing gasifiers and by using hot gas clean-up (EPRI 1990; Meyers 1990; and Seinfeld and Willson 1993). Most recently, studies of hybrid fuel cell/turbine systems have shown that LHV efficiencies of 70% can be achieved on natural gas (Ghezel-Ayagh, Sanderson, and Leo, 1999). In another program by Fuel Cell Energy Inc. (FCE), the goal is to build and test a fuel cell power plant operating on coal-derived gas as a part of the Clean Coal IGCC project.

All of these projects and studies have focused on carbonate fuel cells operating on coal-derived gas. The goal of the project reported here is to identify efficient plant system configurations of coal gasification combined with a planar solid oxide fuel cell (SOFC) and a bottoming cycle.

2 EXECUTIVE SUMMARY

The Solid Oxide Fuel Cell (SOFC) is regarded as one of the most promising power generation technologies for the future. With unmatched thermodynamic efficiencies and the ability to be combined with turbines to form hybrid power plants, SOFC power plants could be of various sizes, ranging in output from a few kilowatts to several hundred megawatts. Traditionally, natural gas is used as the fuel for SOFCs. For large power plants, the use of coal as the fuel becomes a possibility, since the scale permit gasifiers to be integrated in a SOFC-based hybrid power plant. This project studies the integration opportunities between a gasifier and a SOFC-based power plant.

Initial analysis was carried out on a reference Integrated Gasification Combined Cycle (IGCC) plant. This plant includes a BGL oxygen blown gasifier that operates on Pittsburgh No.8 coal feed, two gas turbines, and a steam turbine. This reference plant is estimated to operate with an overall efficiency of 40.8% coal on a HHV basis. In subsequent analyses, one of the two gas turbines in the reference power plant was replaced by SOFC modules. This configuration, referred to as the pre-baseline system, is expected to have a system efficiency of 43%. The primary reasons for the limited performance improvements were identified as the use of status technology fuel cell modules along with a significant amount of fuel being consumed in the combustion gas turbine rather than the more efficient SOFC.

After the initial analysis, a number of system concepts with efficient fuel cell stack thermal management and pressurized SOFC, were proposed and evaluated. Two concepts having the most promising efficiency, cost, and reliability entitlement were downselected from the many configurations evaluated.

After the downselection process, a detailed analysis was carried out on both systems to optimize the overall plant performance. The baseline system was found to be 53.4% efficient at a stack operating pressure of 10 bars, while the alternate configuration had a system efficiency of 53.8%. That is about 10 percentage points more than the efficiency of a state-of-the-art technology IGCC plant.

Two different concepts for CO_2 isolation were evaluated, one based on a Selexol system and the other based on combustion of the spent fuel using pure oxygen from an air separation unit. The Selexol-based CO_2 separation resulted in a performance penalty of about 2.6%, while the oxygen-based combustion resulted in a performance penalty of about 2.2%, for both baseline and alternate systems.

The effect of adding methane to the syngas was found to improve plant performance significantly. This result implies that higher plant efficiencies could be realized if the gasification process parameters are optimized to produce syngas with significant methane content.

This baseline IGFC plant is expected to be cost competitive on a per kW basis with today's IGCC plants, provided the capital cost of the SOFC portion of the plant is consistent with the DOE SECA cost targets. The initial costs of the baseline and alternate concepts were estimated to be \$1654/kW and \$1700/kW, respectively, compared to \$1588/kW for the state-of-the-art IGCC plant. Even with CO_2 isolation, these plant concepts were found to be cost competitive on an initial capital cost basis.

To realize this plant concept, several technology goals must be met, primarily in the SOFC stack. In addition, the turbomachinery and balance of plant (BOP) components will require significant re-engineering.

3 EXPERIMENTAL

No experimental work has been performed as part of this study.

4 RESULTS AND DISCUSSION

4.1 Pre-Baseline Model and Analysis

4.1.1 Approach

The conceptual analysis of the pre-baseline configuration involved the integration of SOFC modules with commercially feasible IGCC elements and syngas treatment. A structured approach was used to analyze each of the necessary subsystems in order to yield a set of optimum elements, which would result in an efficient IGFC system.

The overall system requirements were identified and flowed down to the subsystem level by utilizing a Six Sigma tool, Quality Function Deployment (QFD) analysis.

These candidate subsystems were evaluated against individual sets of subsystem requirements, and the highest-rated subsystem options were integrated into an overall pre-baseline IGFC Design.

4.1.2 System Description

The IGFC system is an evolved system, which combines the current advantages of the IGCC system for the conversion of coal energy into electric power with the highly efficient SOFC technology. For the pre-baseline case, a conventional (available technology) IGCC system with a gasifier/gas cooling/cleanup system, with two GE 6FA+e gas turbines and a bottoming cycle was modified so that one of the gas turbines was replaced by a solid-oxide fuel cell system. This IGFC System included the following subsystems:

- Gasifier subsystem
- Gas cooling and cleanup subsystem
- Air separation subsystem
- Gas turbine subsystem
- Bottoming cycle subsystem
- Fuel cell subsystem
- Fuel cell stack subsystem

The candidates for each of these subsystems were analyzed by means of global and subsystem requirements in order to yield a credible pre-baseline IGFC system.

4.1.3 Major System Development Drivers

Development and integration of the pre-baseline IGFC case were driven by the following concepts:

- Use of near-term available commercial technology whenever possible.
- Use of projected large (MW Size) planar SOFC technology.

- Use of QFD techniques to provide criteria for down-selection of appropriate subsystems.
- System optimization aiming for achievement of 50% short-term and 60% long-term overall system efficiency.

4.1.4 Quality Function Deployment for Subsystems

In order to select a suitable subsystem, an analysis tool, the Quality Function Deployment (QFD) analysis, was used with the following overall DOE expectations and requirements:

DOE Expectations and Requirements

- Low Cost of Electricity (COE)
- Plant capacity (250 MW or greater)
- High efficiency (60% HHV ultimate system efficiency)
- Applicable to use of fuel cells
- “Near Zero” emissions (of traditional pollutants)
- CO_2 reduction or capture
- 2010-2030 Technology feasibility
- Co-product capability (transportation fuels, H_2, etc.)
- Coal flexibility (plus other optional fuels)
- Minimum water usage
- Minimum hazardous waste

These expectations were cross-correlated in a matrix with the following IGFC System Requirements.

IGFC System Requirements

- Plant cost
- System power output
- System efficiency
- System availability
- NO_x Emissions
- CO Emissions
- CO_2 Emissions
- SO_x Emissions
- Maintainability

- Water usage
- Subsystem R&D required
- Technology choice

This yielded the relative ranking of the key system parameters to be used in determining the suitability of any Subsystem for the final IGFC System, as shown in Figure 3. These relative rankings were used as weighting factors for individual Subsystem Requirements. The available commercial offerings for each subsystem were evaluated using this weighted ranking, as shown in Appendix A.

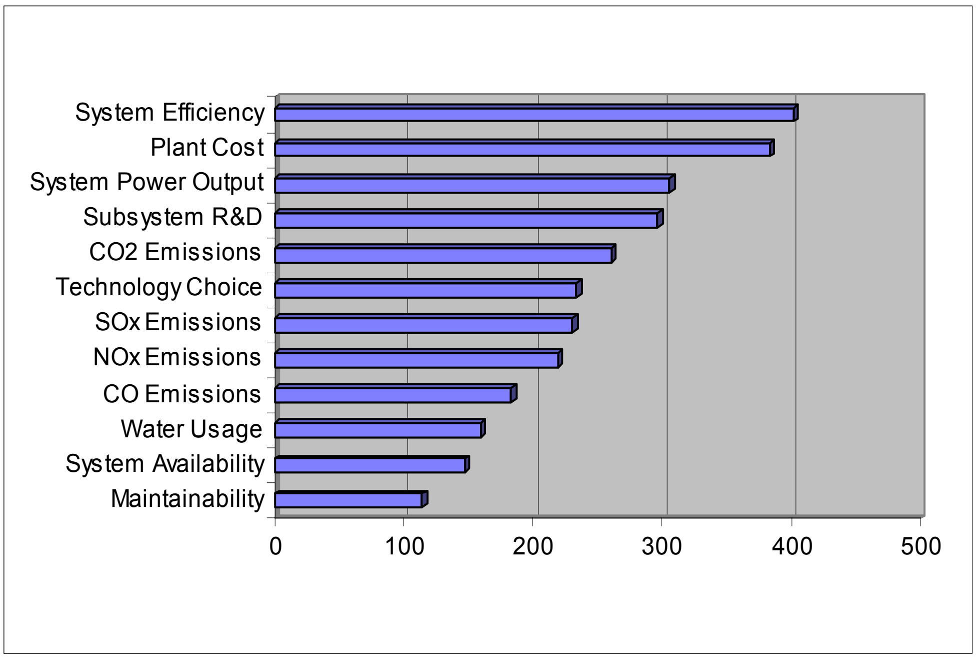

Figure 3. Relative Ranking of Overall System Parameters

4.1.5 Analysis of Pre-Baseline System

The preceding subsystem optimizations must be considered within the framework of existing studies for production of syngas for IGCC systems. A previous IGCC internal study provides the best example for use as a syngas source for the SOFC Fuel Cell Stack. The original BGL IGCC System was modified for integration with the SOFC stack

Syngas from the BGL system is sent to the fuel cell subsystem, which includes a water-gas shift of the syngas to a fuel more suitable for the SOFC fuel cell stack. Fuel from the fuel integration section is then sent to the fuel cell stack. The heat and mass balance is shown in Appendix C and a summary of results is provided in Table 1.

Table 1 Fuel Cell Stack Overview

Material Balance:

Stream No.		FC 1	FC 2	FC 3	FC 4	FC 5
Stream Name		Fuel to FC Stack	Hot Air to FC Stack	Cool Air to FC Stack	Spent Fuel from FC Stack	Vitiated Air from FC Stack
CO	- lbmol/h	1423	0	0	436	0
H2	- lbmol/h	3980	0	0	963	0
CH4	- lbmol/h	406	0	0	0	0
CnHm	- lbmol/h	46	0	0	0	0
H2S+COS	- lbmol/h	0	0	0	0	0
CO2	- lbmol/h	2335	7	15	3648	148
H2O(v)	- lbmol/h	3754	241	507	7418	1006
N2+Ar	- lbmol/h	185	18706	39317	160	58029
SO2	- lbmol/h	0	0	0	0	0
O2	- lbmol/h	0	4959	10424	0	12476
Total Gas:	- lbmol/h	12129	23914	50263	12625	71659
Gas MW	- lb/lbmol	19.09	28.85	28.85	24.82	28.71
Total Gas Mass F	- lb/h	231518	690013	1450287	313390	2057612
Total Flow	- lb/h	231518	690013	1450287	313390	2057612
HHV/Enthalpy	- Btu/lb	3656	0	0	547	0
Energy Flow	- MMBtu/h	846	0	0	171	0
Pressure	- psia	44	44	43	41	41
Temperature	- deg-F	1300	1285	920	1450	1452

Comp	Fuel	Hot Air	Cool Air	Spent Fuel	Vitiated Air
CO	11.7349%			3.4572%	
H2	32.8154%			7.6257%	
CH4	3.3496%			0.0002%	
CnHm	0.3769%			0.0000%	
H2S+COS					
CO2	19.2511%	0.0298%	0.0298%	28.8984%	0.2059%
H2O(v)	30.9506%	1.0090%	1.0090%	58.7551%	1.4035%
N2+Ar	1.5215%	78.2226%	78.2226%	1.2634%	80.9801%
SO2					
O2		20.7386%	20.7386%	0.0000%	17.4105%
Total:	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Analysis of the complete heat and mass balances indicates that mass balances for the complete IGFC system are consistent within 0.002 % and energy balances are found to be consistent within 0.03 %.

Results for the overall net power output and efficiency for the pre-baseline system are given in Table 2.

Table 2. Pre-Baseline Performance Summary

Pre-Baseline System		
Gross Power Gen.		
-Gas Turbines	-kW	70217
-Net Fuel Cell System	-kW	90034
-Steam Turbine	-kW	65207
Sub-Total:	-kW	225458
In-Plant Power Cons.		
-Gasification	-kW	2810
-Air Seperation	-kW	13158
-Combined Cycle	-kW	2149
-Cooling Water CC	-kW	365
-Cooling Water PP	-kW	782
-BOP+Misc	-kW	1283
Sub-Total:	-kW	20548
Net Power To Grid	**-kW**	**204910**
Heat Input, HHV	-MMBtu/h	1625.2
Net Heat Rate, HHV	-Btu/kWh	7931.4
Net Efficiency, HHV	**-%**	**43.0**

4.1.6 Summary of Pre-Baseline system trade-offs

This pre-baseline IGFC system is presented as a commercially feasible integration of an advanced SOFC with current gas turbine technology. The overall efficiency of 43.0% presents a 2.2% improvement in system efficiency over the equivalent IGCC system.

Most of the system trade-offs in the pre-baseline system involve the integration of the fuel cell stack with a fixed gasifier system and a sub-optimized fuel integration system. Within the bounds of the available gasifier system information, and the medium-fidelity HYSYS simulation of the fuel integration system, the pre-baseline system results provide a realistic benchmark case for further optimization in order to yield an acceptable baseline system.

The CO level in the fuel gas for the fuel cell stack system could be kept within the recommended 15% maximum CO level (a nominal 12% CO level) by use of a single WGS reactor in the fuel cell subsystem since the syngas from the gasification system was highly saturated with H_2O. Effects of optimization of the shift level for the syngas from the gasifier system would be the subject of post-baseline studies.

Integration of fuel cell heat energy has not been fully optimized in the pre-baseline case because of the minimal heat energy integration with the gasifier and fuel integration systems. More extensive optimization of heat exchanger approaches, pinches and configurations would be possible in future studies of IGFC systems with more complete integration of the fuel cell system and the gasifier system, as well as alternate cooling strategies for the fuel cell stack system.

This pre-baseline system configuration was set up with initial specifications of pressure drops, cell temperature rises, fuel utilization, and cell losses. The fuel cell stack operating pressure was limited to 3 bars consistent with status technology.

4.2 Design Concept Development

A baseline hybrid SOFC system was designed around the BGL gasifier. Since the gasifier system (gasifier, gas cleanup, and ASU) was fixed, efforts were centered around the design of the fuel cell modules and bottoming cycle and their integration with the gasifier system.

4.2.1 Approach and Analysis Basis

The following considerations were taken into account for proceeding from pre-baseline to baseline**.**

- Air management. Air is needed in the SOFC stack to supply oxygen as well as to cool the stack. Normally, about 5 to 10 times the stoichiometric amount of air is needed on the cathode side for heat removal. This air needs to be fed to the cell at an elevated temperature to ensure proper stack operation. The issue of supplying heat to raise the air to the operating temperature is one of the challenging problems. Once the air has been heated to the operating temperature, it could be passed through multiple stacks.
- Pressure drop in the piping. The piping to and from the stack is extensive, as air and fuel need to be supplied to every single cell. As a result the system experiences a substantial pressure drop. The piping must be made large enough to slow the gases down but not so large as to cause excessive cost penalty. As a general rule of thumb, all piping external to the fuel cell stacks was designed to keep fluid velocities below 30 m/s (about 100 ft/s). This solution proved quite satisfactory in terms of pressure drop and size.
- Heat loss from the piping. Loss of enthalpy along the length of piping could have a substantial effect on the plant performance. This problem can be solved easily and inexpensively by using a reasonable quantity of insulation, and by designing the plant so that the hot-side piping lengths are kept to a minimum.
- Use of large-sized turbomachinery components. For typical large industrial gas turbines, compressor efficiencies are in the high 80s and turbine efficiencies are in the low 90s. These are advanced, high performance components, and their use adds very large performance gains to the plant. The plant is designed to use one or two of these large-scale gas turbines. The alternative approach would be to use microturbines for each fuel cell module. While this solution simplifies the piping issues, the degradation in performance is substantial because of the relatively poor component efficiencies associated with small-sized turbo-machinery.
- Use of SOFC as a topping cycle. Fuel cells are more efficient than combustion-based processes. In order to maximize cycle efficiencies, the entire topping cycle should consist of fuel cells; while the excess heat generated by the fuel cells is recovered in the bottoming cycle.

4.2.2 Plant description

Nominal plant layout

The IGFC plant is sized for a nominal power output of 300 MW. The unit is connected to a BGL gasifier unit, whose syngas output is scaled to 60 kg/s (132 lbm/s, 475200 lbm/hr). The syngas has a molecular weight of 19.1 and HHV of 8503.8 kJ/kg (3656 Btu/lb). The syngas composition fed to the fuel cell is shown in Table 3 (mass fractions are given).

Table 3. Fuel Cell Syngas Composition

	Mass Fraction
H_2	0.03
CO	0.17
CH_4	0.03
H_2O	0.29
CO_2	0.44
N_2	0.01
AR	0.01

The syngas output of the AGR system is distributed uniformly among the forty fuel cell modules in the plant. The air and fuel flow rates inside each module are shown in Figure 4.

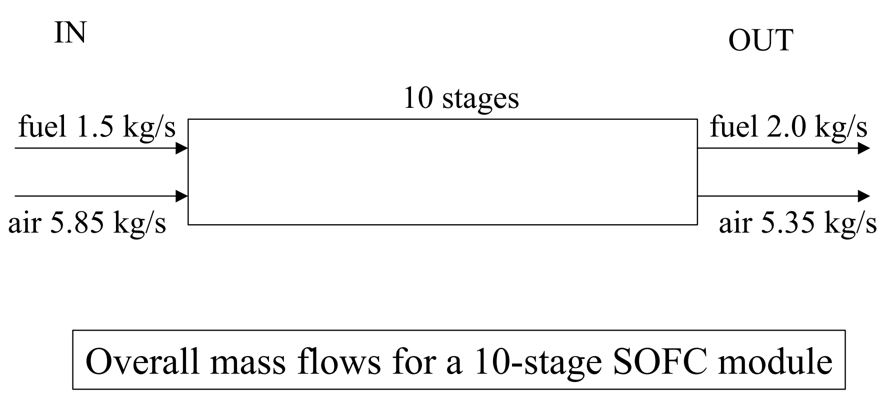

Figure 4. Overall Mass Flow

The plant consists of the following major components:

- the gasifier system (gasifier, ASU, clean-up system)
- forty SOFC modules

- one or two gas turbines
- one HRSG
- one steam turbine
- generators for the gas turbine and the steam turbine

Fuel Cell Modules

A SOFC module is a refractory-lined pressure vessel that includes the following components

- five to ten SOFC stages
- heat exchangers, mixers, or similar units in between SOFC stages
- current collector bus bars
- manifolds for fuel distribution

In this context a stage is viewed as a SOFC stack, or several stacks placed side by side. The baseline design is viewed as three stacks side by side. Thermal insulation with a thickness of 5 cm is placed inside the pressure vessel to preserve strength in the steel casing material and to reduce heat loss from the pressure vessel. The dimensions are in meters.

The stack characteristics are as follows.

- Cell area: 1500 cm^2
- Current density: 0.7 A/cm^2 (power density 0.49 W/cm^2 at cell operating voltage of 0.7 Volts)
- Cell power 735 W; stack power 154.35 kW; stage power 463.05 kW

The above performance parameters are comparable to SECA goals of .35 W/cm^2 at 0.75 volts and 80% utilization. The chosen operating voltage is lower than SECA goals, while the power density is higher. It should also be noted that the SECA goals are for ambient pressure operation, while the IGFC stacks are expected to operate at significantly higher pressures.

Since a 3-stack stage makes 0.46 MW DC power, a pressure vessel with 10 stages would be able to produce 5 MW nominally. The pressure vessel would be 2 m in OD and about 14 m long.

The space between the stacks is large enough to bring the fuel manifolds in and out of the stack. The space between the stacks and the refractory liner would also house the fuel lines and electrical bus bars.

Plant layout

Since large gas turbines have higher component efficiencies, it is more efficient to compress the air going to the SOFC modules with one or two large compressors, and similarly expand the SOFC output flow with one or two large turbines. This approach necessitates a means to distribute the flow uniformly among all 40 of the modules and collect it to burn and expand in the turbine. Various concepts to do this were investigated, and it was decided that the simplest and the most effective arrangement was to have plenum chambers do the air distribution and collection.

The fuel cell modules were arranged in two rows (one on top of the other), adjacent to the gas turbine with two plenums on either side of the fuel cell modules. The plenum further away from the gas turbine is the cold side plenum, while the one closest is the hot side. The compressor outlet flow is collected in the cold side plenum (where the temperature is about 300ºC) and distributed among the fuel cell modules. The large-diameter pipes providing passage to and from the plenums make sure that the pressure drop is minimal. The outlet flow from the modules is collected in the hot side plenum, after which it is mixed with the spent fuel from the modules and burned in the burner before passing into the turbine.

Since the length of the piping is different for each module, the piping must contain auxiliary pressure drop devices to ensure equal pressure differential in all the pipes.

Material Choices for the Fuel Cell Modules:

The primary assumption to meet the requirements of the SOFC module are given below:

- Hot section piping mean temperature is 800°C and the cold section piping mean temperature is 300°C.
- All the piping and the cold section plenum chambers are externally insulated. The hot section plenums and the fuel cell modules are refractory lined on the inside. Fiber wool with thermal conductivity 0.05 W/mK and 5 cm thickness is used for external insulation.
- The fuel cell module and the hot plenum are refractory lined.
- The only part of the piping system that needs stainless steel is the connection between the fuel cell module output and the hot plenum. Because the pipes are relatively small (30 cm ID), 304 stainless is used for this section of the piping. All the remaining piping system is of carbon steel.
- The following pipe dimensions were arrived at in compliance with ASME pressure vessel codes.

Cold side pipes	30 cm ID	0.5 cm wall	214/226
Duct	150 cm ID	2.75 cm wall	214/226
Plenum	500 cm ID	9.0 cm wall	214/226
Module	200 cm ID	3.75 cm wall	214/226
Hot side pipe	30 cm ID	4.25 cm wall	304

4.2.3 Pinch Analysis

In this analysis, heat integration in only one of the fuel cell pressure modules described in the plant layout section is analyzed since all other pressure modules will replicate the design. In order to understand the overall heat integration concept of the process streams in the pressure module, a simplified pinch analysis was performed. This analysis quickly revealed that, for number of cells, n, greater than three, the process hot streams have more heat content than needed to heat the cold streams.

4.2.4 Candidate Baseline Configurations

A number of candidate baseline configuration concepts were developed, and a baseline system was down-selected for further detailed analysis and optimization.

4.2.4.6 Down-Selection to Baseline concept

A design trade-off analysis was performed using standard Design for Six Sigma (DFSS) tools to down-select from the five proposed concepts. This down-selection was made according to the following three critical aspects of the proposed systems

- Achievable maximum efficiency
- Initial capital cost
- System reliability

Preliminary performance evaluation of all of the concepts was performed. The concepts were ranked according to the above-mentioned criteria. The outcome of the analysis is depicted in Figure 5. Concept 2 was selected as the "baseline" for its simplicity, which leads to a lower cost and higher reliability. Concept 4 was also selected for further study as the "alternate". Although the alternate has the risk of higher cost and lower reliability, it has potential for higher efficiency.

Configuration	Rank	Efficiency	Stages	Recycle	Complexity	Cost Potential
Concept 1	3	52.5	10	Yes	Medium	Low
Concept 2	1	51.8	10	yes	Low	Low
Concept 3	5	51.0	10	No	High	Medium
Concept 4	2	52.5	5	No	High	Medium
Concept 5	4	52.2	10	Yes	High	High

All systems evaluated at Pressure Ratio of 8.0

Figure 5. Down-Selection Trade-off Matrix

4.3 Baseline Design and Modeling

4.3.1 Description of the Baseline and Alternate

In this section the detailed layout of the baseline and alternate concepts are presented. The discussion centers on the SOFC and gas turbine part of the plant. The gasifier unit (including clean-up and ASU) and the bottoming cycle stay the same in both cases.

4.3.1.1 Baseline concept

The plant consists of several fuel cell modules. Gases are supplied to the modules by one or two large gas turbines and a syngas expander. Several modules are served by the same gas turbine system. Compressed air is fed to a plenum and distributed equally to the modules. On the fuel side, high-pressure syngas is expanded down to the fuel cell operating pressure and distributed to the various modules and cells inside the module in a similar way.

The design point number of stages per module is ten. The fuel cell stages have built-in fuel pre-heaters. The spent fuel from all the stages is collected and sent to a burner to burn with the cathode exhaust.

4.3.1.2 Alternate concept

In the alternate concept the compressed air from station is preheated to the fuel cell operating temperature through a set of parallel heat exchangers.

4.3.2 Major assumptions in the modeling

The pressure drops and the heat losses at the plant design point are given in Table 4 and are summarized graphically in Figure 6. The actual fuel cell stage pressure losses were varied from the nominal value as a function of the local flow properties at each stage. All components inside the pressure vessel stack modules have been sized for low airflow velocities.

Table 4. Design Point Air Pressure and Heat Losses

Design Point Air Pressure Losses			
Component	**Units**	**Baseline**	**Alternate**
Compressor Inlet	inch H2O	3	3
Compressor Extraction	ΔP/P (%)	2	2
Cold Piping & Plenum	ΔP/P (%)	0.13	0.13
Recycle Mixer	ΔP/P (%)	0.1	0
Air Preheat HEX cold	ΔP/P (%)	0	0.1
Module Inlet	ΔP/P (%)	0.1	0.1
Fuel Cell Stage (nominal)	ΔP/P (%) each	0.1	0.1
Fuel Preheat HEX hot	ΔP/P (%) each	0.05	0.05
Air Preheat HEX hot	ΔP/P (%) each	0	0.1
Air Injection Mixer	ΔP/P (%) each	0.1	0.1
Module Outlet	ΔP/P (%)	0.1	0.1
Hot Piping & Plenum	ΔP/P (%)	0.2	0.2
Turbine Plenum	ΔP/P (%)	2	2
Burner	ΔP/P (%)	3	3
Back Pressure	inch H2O	15	15
TOTAL (compressor exit to turbine inlet)	**ΔP/P (%)**	**11.24**	**10.32**

Design Point Heat Losses		
Component	**Units**	**Loss**
Cold Piping & Plenum	BTU/s	116.1
Pressure Module + Plenum + Hot Piping	BTU/s	161.4

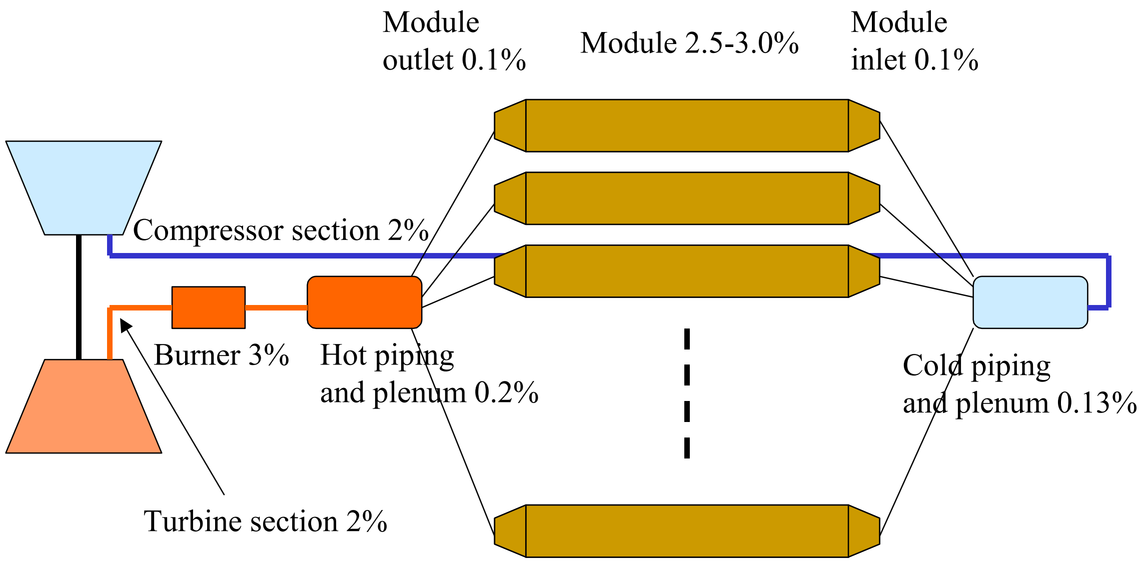

Figure 6. Summary of Baseline Design Point Pressure Drops (ΔP/P)

A maximum fuel cell exit temperature of 775°C was assumed. The largest allowable temperature gradient across the fuel cell stage was assumed to be 125°C, meaning that the inlet temperatures can be no less than 650°C.

A two-pressure steam cycle with reheat was used for the bottoming cycle. In order to use a two-pressure steam system, the minimum allowable temperature for the HRSG inlet was taken to be 1000°F (538°C). The maximum HRSG inlet temperature was 1280°F (693°C), set by material temperature limits. For the CO_2 isolation study, the lower temperature limit on the HRSG inlet was relaxed slightly to 900°F (482°C), although the bottoming cycle efficiency was correspondingly reduced.

4.4 Final Conceptual Design Performance Summary

The performance results for the baseline and alternate designs are discussed below.

4.4.1 Baseline Performance

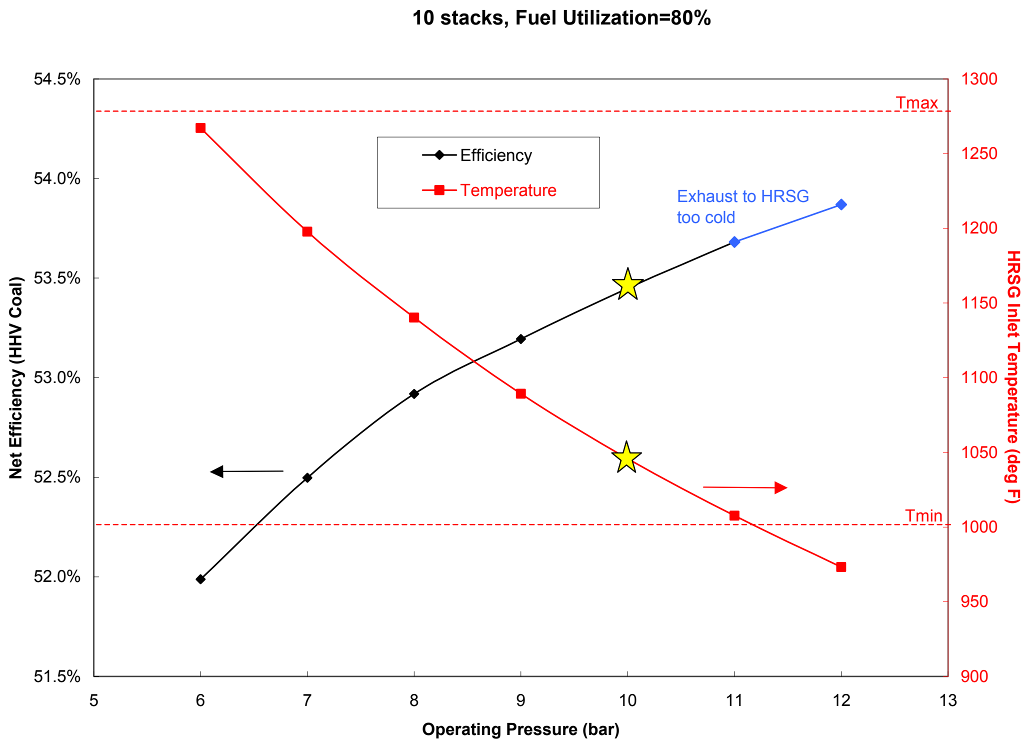

Figure 7. Overall Baseline Performance vs. Pressure

Figure 7 shows the overall plant performance for the baseline design versus fuel cell operating pressure. The HRSG inlet temperatures are also shown in red. The plant efficiency increases with operating pressure for the same compressor inlet mass flow rate and fixed fuel utilization. At operating pressures above 10 bar, the HRSG inlet temperature drops below 1000°F. Below this temperature, the bottoming cycle performance begins to suffer as it becomes difficult to drive a two-pressure reheat steam turbine. This HRSG limit prevents operation at very high pressures and higher efficiencies. At low pressures (below 6 bar), the HRSG inlet temperature exceeds the assumed maximum (1280°F). The design point is shown as a star. At the design point pressure of 10 bar, the net plant efficiency is 53.4% (Coal HHV basis).

4.4.1.1 Sensitivity Analysis

The sensitivity of the baseline plant efficiency to various parameters was examined.

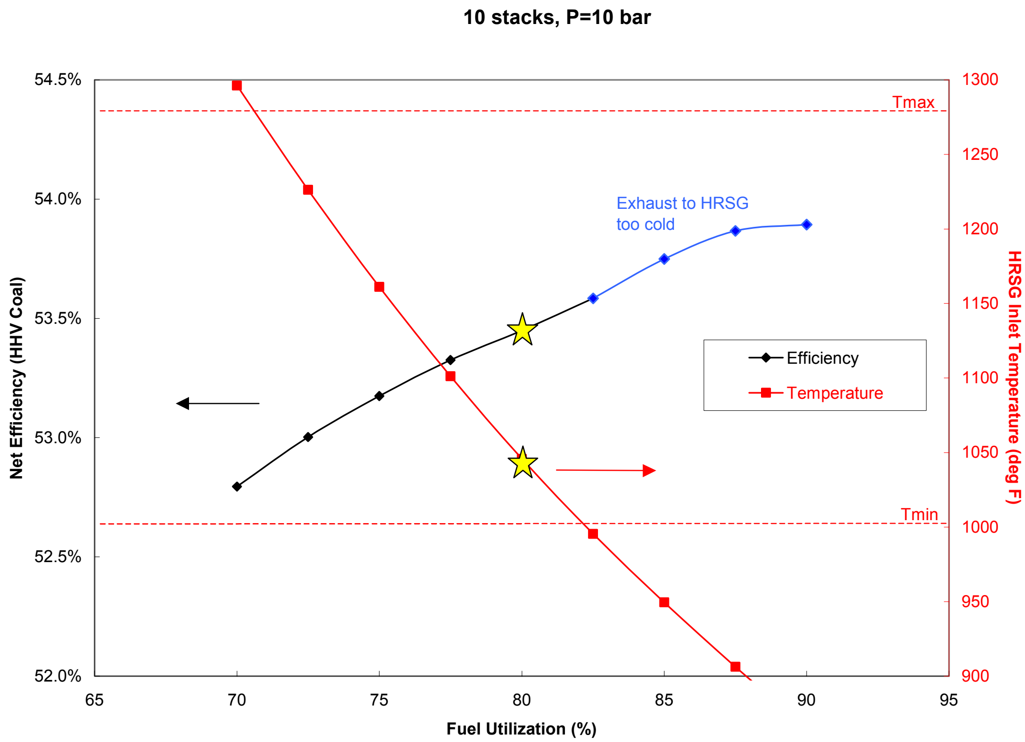

Figure 8. Effect of SOFC Fuel Utilization

Figure 8 shows the effect of SOFC fuel utilization on plant efficiency and HRSG inlet temperature. Higher fuel utilization at a fixed stage exhaust temperature raises the plant efficiency, since the SOFC topping cycle is the most efficient use of fuel. However, as more fuel is consumed in the fuel cell, there is less fuel in the anode exhaust available for combustion. The HRSG inlet temperature drops rapidly, putting an upper limit of about 82% fuel utilization for a two-pressure reheat bottoming cycle. The design point was chosen to be 80% fuel utilization.

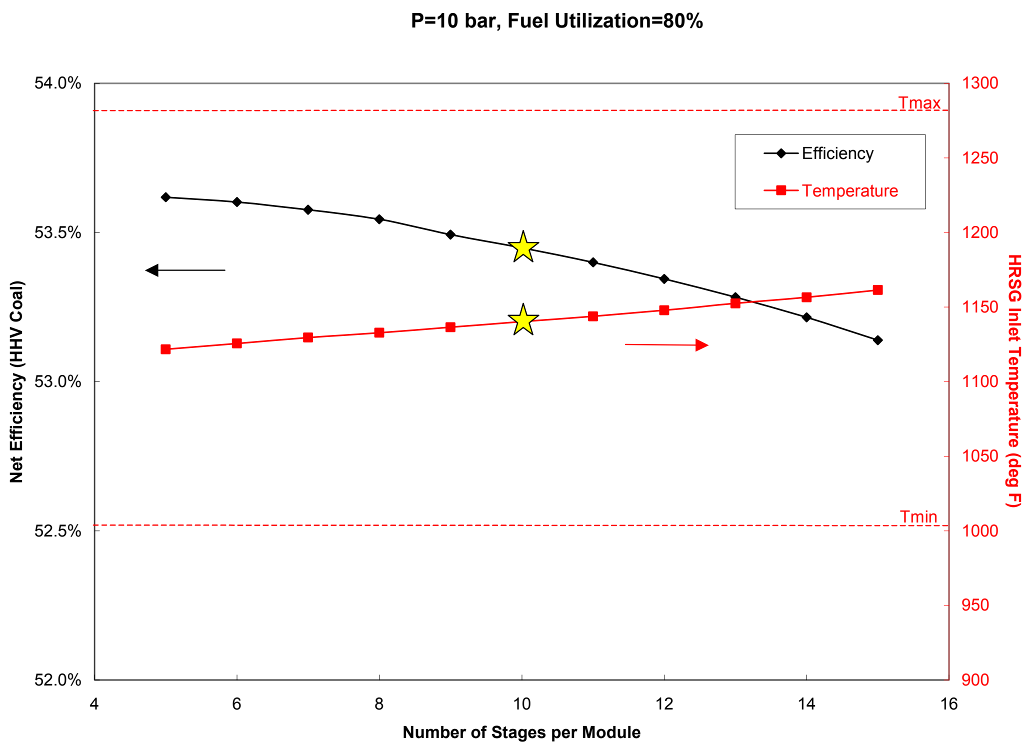

Figure 9. Effect of Number of Stages

Figure 9 shows the effect of the number of stages in series per module on plant efficiency. The efficiency decreases slightly as additional stages are added in series. The cathode oxygen concentration decreases slightly as air passes through more stages in series. The design point was chosen at ten stages per module. Slightly higher efficiency could be achieved with fewer stages, but at an increased capital cost due to additional number of modules needed to achieve the same net plant power.

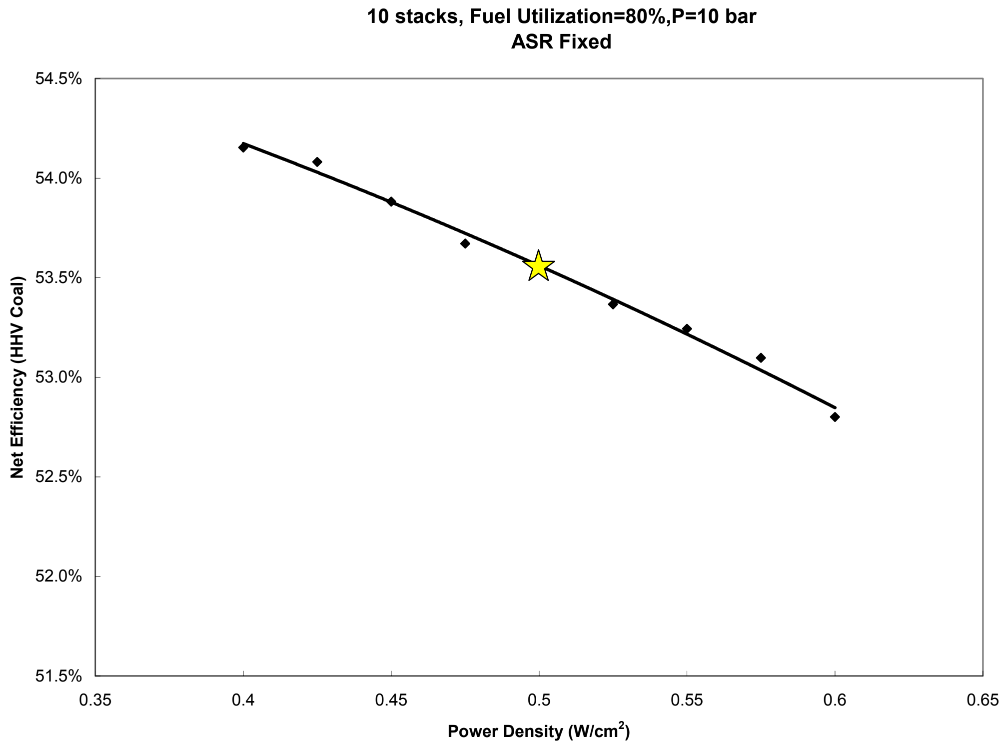

Figure 10. Effect of Fuel Cell Power Density

Figure 10 illustrates the effect of fuel cell power density at a fixed Area Specific Resistance (ASR). For a fixed technology cell, fuel cell efficiency decreases at higher power density. However, capital cost could be reduced as the total number of fuel cell modules will be reduced in proportion to the power density increase. Conversely, if efficiency was the sole criteria, the fuel cells could be operated at lower power densities and increased performance.

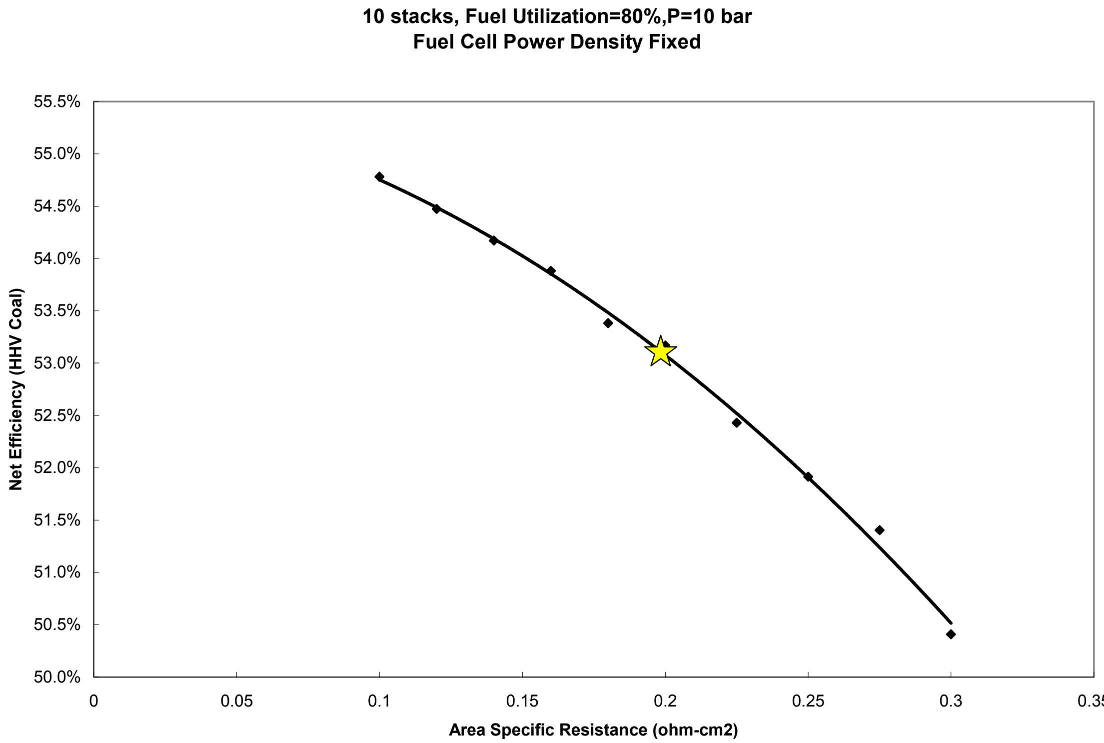

Figure 11. Effect of Area Specific Resistance

The sensitivity of the net plant efficiency to the fuel cell area specific resistance (ASR) is shown in Figure 11. At a fixed power density and fuel utilization, if fuel cell technology is improved and ASR is lowered, the plant efficiency increases as shown in this figure.

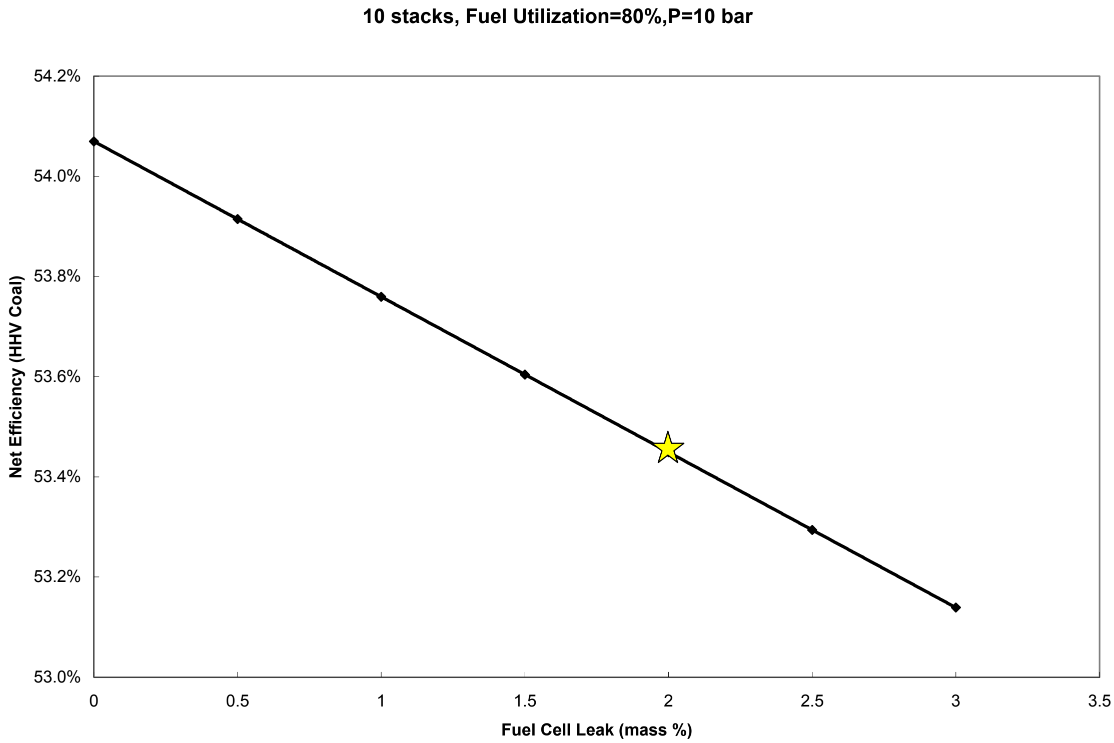

Figure 12. Effect of Fuel Cell Leak

The sensitivity of plant efficiency to fuel cell leak is shown in Figure 12. Total fuel leak (mass basis) is shown on the x-axis. Half the leak is assumed to be at the inlet of the cell, the other half is at the exit of the cell. Since the anode side is slightly pressurized versus the cathode, the fuel leaks into the cathode air. The design point was chosen at 2% fuel leak. Significant improvement in the fuel cell plant performance can be achieved if the fuel leak can be reduced. Such a reduction may be feasible with large area cells, as the total sealing length is reduced considerably.

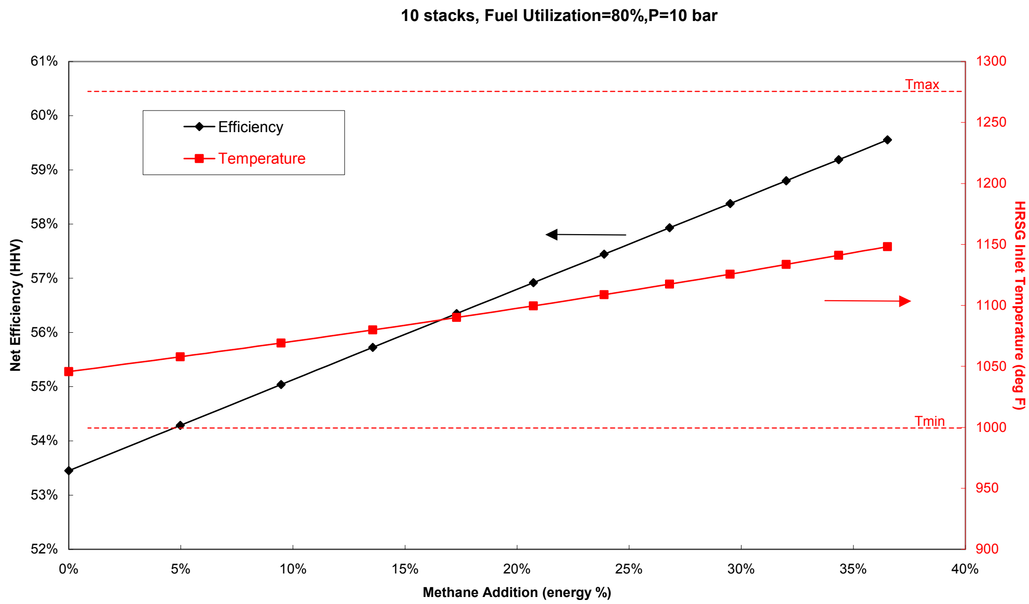

Figure 13. Effect of Methane Addition

The effect of methane addition to the syngas is shown in Figure 13. This was done to simulate a gasifier that produces a higher methane content syngas. Methane addition raises the energy content of the fuel and also provides some additional cooling of the cells as the methane is internally reformed, improving the plant efficiency. In order to achieve a net plant efficiency of 60% (HHV basis), over 35% of the fuel energy must come from methane.

4.4.2 Alternate Design Performance

The performance of the alternate design is compared with the baseline design. Both systems were modeled with equal fidelity.

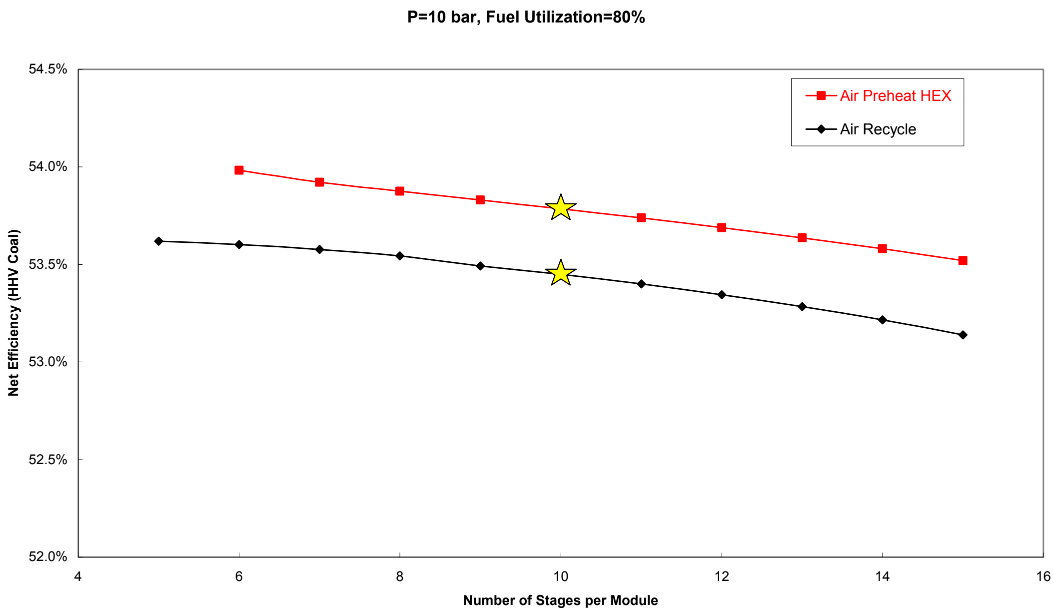

Figure 14. Efficiency Comparison of Baseline and Alternate

Figure 14 compares the performance of the baseline design and the alternate at a fixed operating pressure (10 bar). The alternate design has slightly higher efficiency by about 0.4%, regardless of the number of stages. Although the alternate system is capable of slightly higher efficiency, it may have higher capital costs and lower reliability than the baseline system, as discussed later.

4.4.3 Performance Summary

The power generation breakdowns for the baseline and alternate systems are given in Table 5. The reference IGCC case and the pre-baseline case have also been included for comparison. In the pre-baseline case, the efficiency was improved by 2.2% over the IGCC case simply by sending half the syngas to a fuel cell power island, with minimal heat and pressure integration. This concept also suffered from the fact that the stack operating pressure was only 3 bars, consistent with status technology. This system had only four stages in series and the pressure losses were assumed to be 2% per stage. The baseline system pressure module loss is only about 4% for ten stacks in flow series. In the baseline and alternate systems, the efficiency has been further improved by sending all of the syngas to the highly-efficient fuel cell topping cycle and integrating the fuel cell island with the gas turbines and HRSG. All of these factors significantly increase the systems performance relative to the pre-baseline configuration. A review of the baseline and alternate system performance presented in Table 7 indicate that the primary difference in net performance is the recycle blower power consumption.

Table 5. Baseline Performance Summary

Configuration		IGCC	Pre-Baseline	Baseline	Alternate
Gross Power Gen.					
Gas Turbines	kW	180000	70217	96059	95563
Syngas Expander	kW	0	0	10162	10162
Net Fuel Cell System	kW	0	90034	181038	182912
Steam Turbine	kW	65200	65207	25518	24374
Sub-Total:	kW	245200	225458	312777	313011
In-Plant Power Cons.					
Gasification	kW	3211	2810	3196	3196
Air Separation	kW	15034	13158	14966	14966
Combined Cycle	kW	2190	2149	1333	1312
Cooling Water CC	kW	340	365	226	223
Cooling Water PP	kW	894	782	485	477
Recycle Blowers	kW	0	0	1554	0
BOP+Misc	kW	1379	1283	1459	1459
Sub-Total:	kW	23047	20548	23220	21633
Net Power To Grid	**kW**	**222153**	**204910**	**289557**	**291378**
Heat Input, HHV	MMBtu/h	1856.9	1625.2	1848.5	1848.5
Net Heat Rate, HHV	Btu/kWh	8358.6	7931.4	6383.9	6344.0
Net Efficiency, HHV	**%**	**40.8**	**43.0**	**53.4**	**53.8**

4.5 CO_2 Isolation

4.5.1 Description of CO_2 Isolation Concepts

Two methods for isolating CO_2 from the exhaust were considered. The first was a Selexol-based physical absorption system with anode recycle. The second method combusted the spent fuel with pure O_2 from the ASU rather than with the cathode exhaust. Ideally, this creates a fuel exhaust that is almost completely composed of CO_2 and H_2O. The water can be easily condensed out, isolating the CO_2.

4.5.2 CO_2 Isolation Results

The plant performance with CO_2 isolation and sensitivity to various factors are presented here.

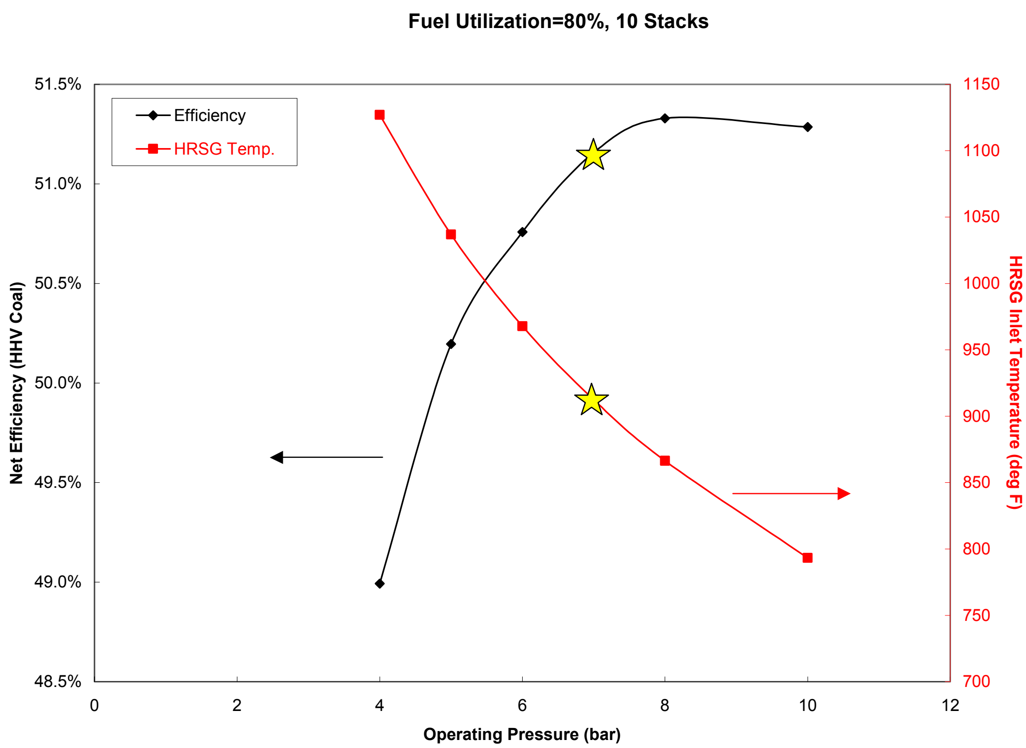

Figure 15. Plant Performance with CO_2 Isolation by Selexol

Figure 15 shows the performance of the plant with 75% of the spent fuel being recycled to the CO_2 capture loop. CO_2 isolation via Selexol imposes a work penalty, thereby lowering the system efficiency compared to the baseline plant. CO_2 isolation via fuel recycle also limits the operating pressure to about 7 bar because less spent fuel is available for combustion, and the corresponding HRSG inlet temperature is lower. The minimum HRSG inlet temperature required for a two-pressure reheat system has been lowered to 900°F to allow operation at reasonable pressure, even though the steam bottoming cycle performance suffers. Higher operating pressure and corresponding higher plant efficiency are possible if less spent fuel is recycled, but the amount of CO_2 captured will decrease. These trends are shown in Figure 16.

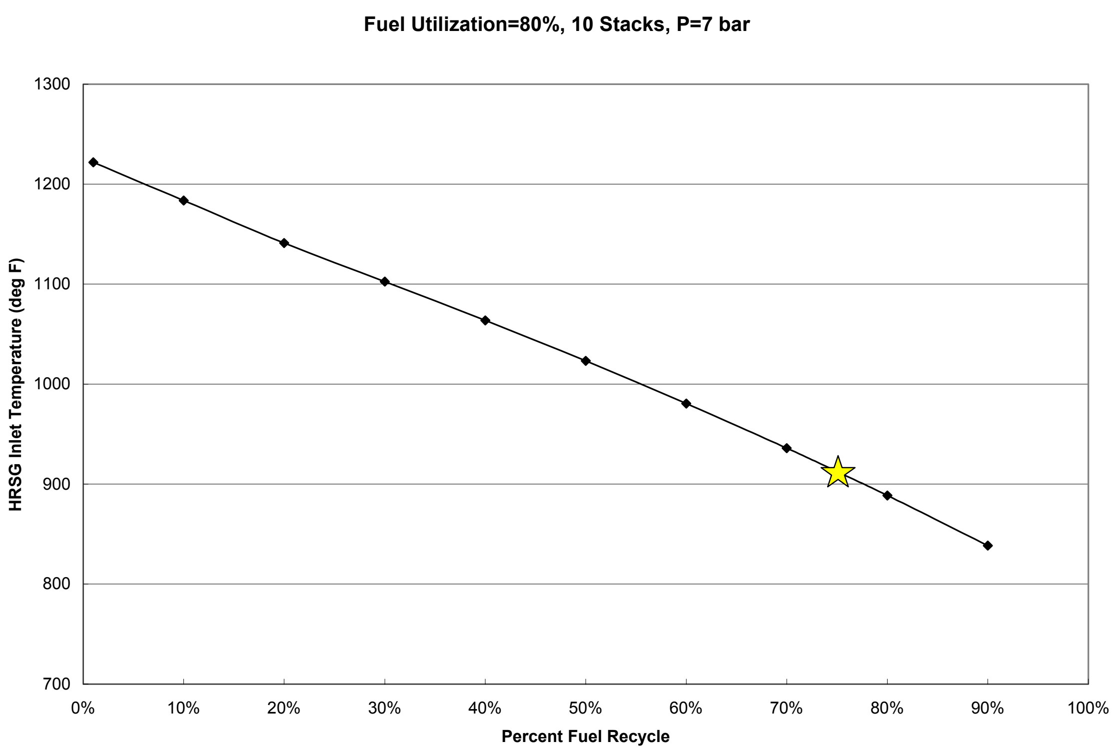

Figure 16. Effect of Fuel Recycle on HRSG Temperature

Figure 16 shows the effect of fuel recycle (mass fraction) on the HRSG inlet temperature. As additional fuel is recycled, less is available for combustion and the turbine exhaust temperature decreases. To maintain a minimum HRSG inlet temperature of 900°F at an operating pressure of 7 bar, no more than 75% of the anode exhaust can be recycled. To maintain an HRSG inlet temperature over 1000ºF at an operating pressure of 7 bar, no more than 50% of the anode exhaust can be recycled.

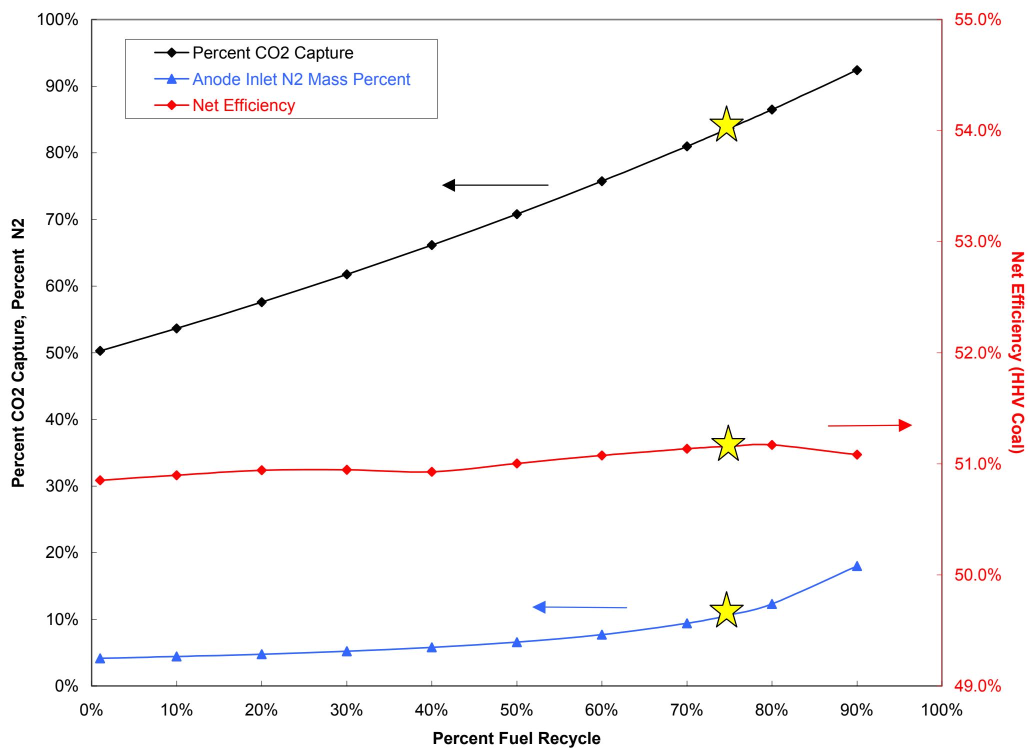

Figure 17. Effect of Fuel Recycle on CO_2 Isolation

Figure 17 shows the effect of fuel recycle on plant performance and CO_2 isolation. As more fuel is recycled and less is combusted, the fraction of CO_2 that is captured rises. At 75% fuel recycle, over 80% CO_2 capture is feasible. The net efficiency shown in red does not significantly increase because the operating pressure has been held constant at 7 bar. At lower fuel recycle fractions, the pressure ratio could be increased and efficiency would increase as described above.

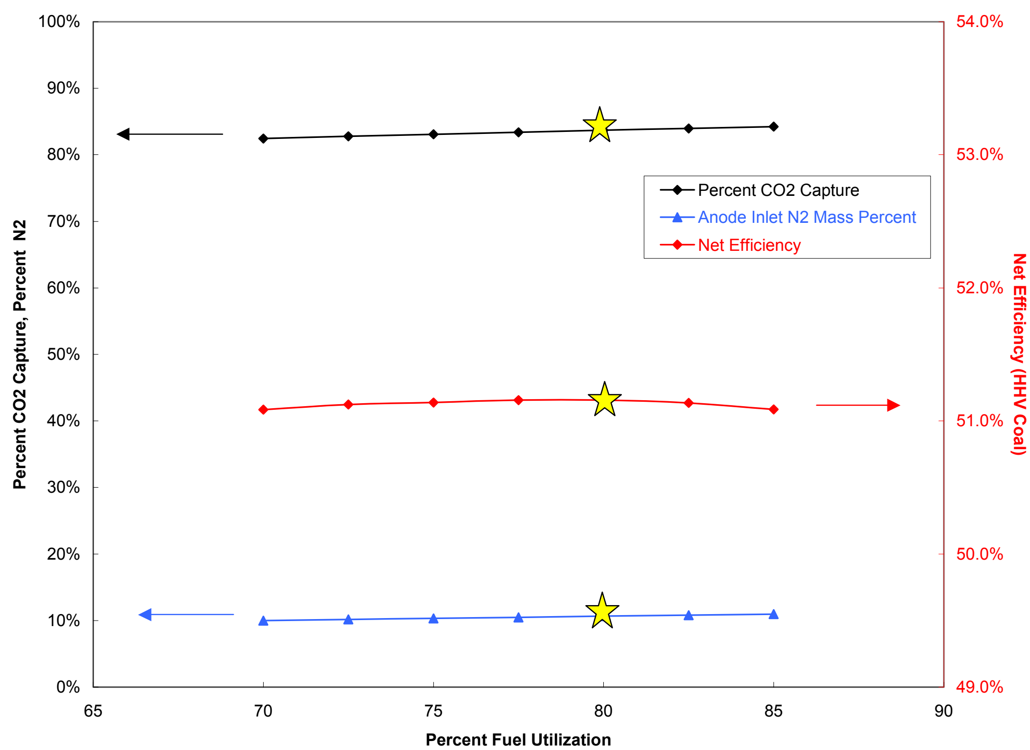

Figure 18. Effect of Fuel Utilization on CO_2 Isolation

The effect of fuel use on plant performance and CO_2 isolation is shown in Figure 18. Because 75% of the spent fuel is recycled, fuel utilization has only a minimal effect. With anode recycle, the fuel cells could be operated at lower fuel utilization at the same plant efficiency, relaxing some of the technology requirements of the fuel cells. This is in contrast to the baseline concept, which has no anode recycle. As described in the Sensitivity Analysis section, for the baseline plant with no anode recycle, the efficiency decreases as the fuel utilization is lowered.

The performance summary for CO_2 isolation concepts is given in Table 6. The CO_2 isolation concepts have been modeled with both the baseline air recycle and alternate air preheat. For reference, the standard baseline and alternate without CO_2 isolation from Table 5 are also included.

Table 6. Performance Summary of CO_2 Isolation Concepts

Configuration		Baseline	Alternate	Selexol, Baseline	Selexol, Alternate	Pure O_2, Baseline	Pure O_2, Alternate
Gross Power Gen.							
Gas Turbines	kW	96059	95563	42699	42862	92206	91685
Syngas Expander	kW	10162	10162	18959	18973	10162	10162
Net Fuel Cell System	kW	181038	182912	226666	228040	181038	182912
Steam Turbine	kW	25518	24374	13320	11673	26067	24991
Sub-Total:	kW	312777	313011	301644	301548	309473	309750
In-Plant Power Cons.							
Gasification	kW	3196	3196	3196	3196	3196	3196
Air Separation	kW	14966	14966	14966	14966	23225	23225
Combined Cycle	kW	1333	1312	1164	1133	1369	1348
Cooling Water CC	kW	226	223	198	192	233	229
Cooling Water PP	kW	485	477	424	412	498	490
Selexol Plant	kW	0	0	2558	2558	0	0
Condensers	kW	0	0	299	299	0	0
Recycle Blowers	kW	1554	0	2558	0	1554	0
BOP+Misc	kW	1459	1459	1459	1459	1459	1459
Sub-Total:	kW	23220	21633	26822	24216	31534	29947
Net Power To Grid	**kW**	**289557**	**291378**	**274822**	**277332**	**277939**	**279803**
Heat Input, HHV	MMBtu/h	1848.5	1848.5	1848.5	1848.5	1848.5	1848.5
Net Heat Rate, HHV	Btu/kWh	6383.9	6344.0	6726.2	6665.3	6650.8	6606.5
Net Efficiency, HHV	**%**	**53.4**	**53.8**	**50.7**	**51.2**	**51.3**	**51.6**

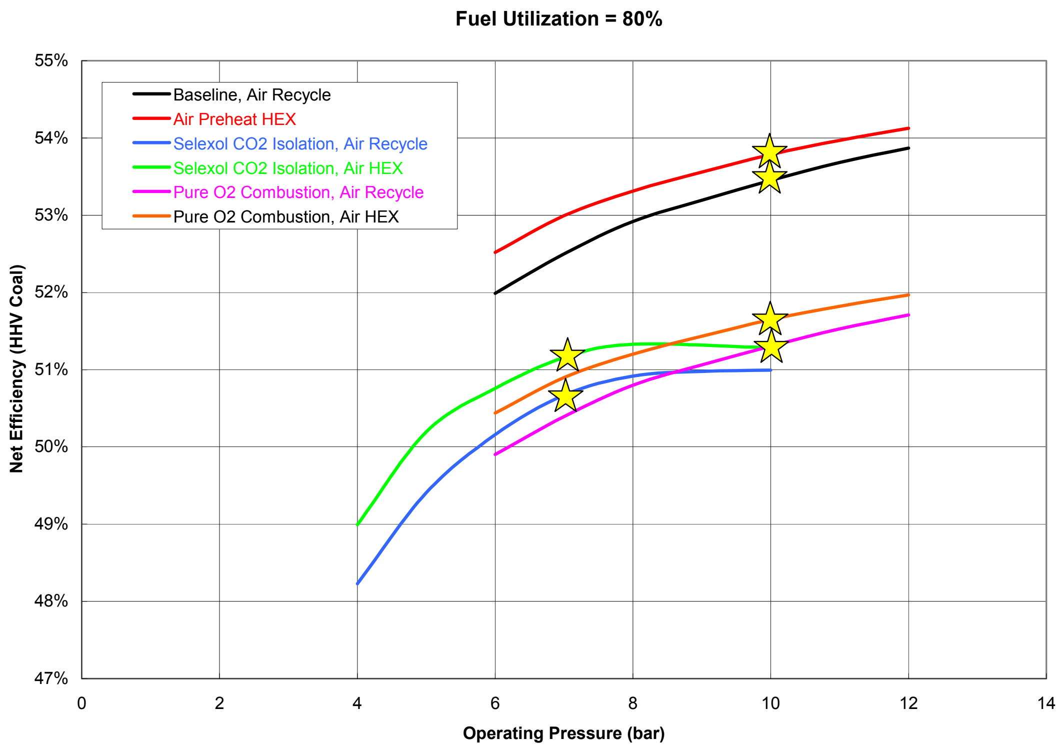

Figure 19. Performance Comparison

Figure 19 summarizes the efficiency of the baseline, alternate, and various CO_2 isolation systems versus operating pressure. The design point for each system is shown with a star. The alternate system has the highest net efficiency at 10 bar of 53.8% on a coal HHV basis. The baseline system has a slightly lower efficiency of 53.4% at 10 bar. Although the alternate system is capable of slightly higher efficiency, it may have higher capital costs and lower reliability than the baseline system, as will be discussed later. Both systems improve with increasing operating pressure.

The Selexol-based CO_2 isolation system results in an efficiency of 50.7% for the baseline and 51.2% for the alternate. Both systems optimize at an operating pressure of about 7 bar. The pure-oxygen combustion CO_2 isolation system results in an efficiency of 51.3% for the baseline and 51.6% for the alternate. Both systems operate at 10 bar.

4.6 Cost Analysis

Estimates of the capital cost were made for the IGCC (reference) case along with the baseline and alternate cases. There were two variations for CO_2 separation, one based on Seloxol process and the other based on pure O_2 combustion. Table 7 summarizes the findings.

The following assumptions were made in this estimate.

- The SOFC costs are consistent with the cost targets laid out by the DOE SECA program on a $/kW basis.
- Gasification costs are specific to the gasifier chosen for this study (BGL) and are estimated from internal GE numbers
- Other component costs were estimated based on scaling of existing components in a typical power plant.

The $/kW capital cost for the baseline and alternate IGFC cases are smaller than the corresponding figure for the reference IGCC configuration. However, the total plant capital cost is higher for the IGFC configurations. Thus the relatively high efficiency of the IGFC plant plays a vital role to keep the $/kW capital costs down.

The capital costs of the baseline and alternate concepts were estimated to be $1654/kW and $1700/kW respectively (Table 7). The difference in costs between the concepts is attributed to the differential cost of replacing the recycle blowers in the baseline configuration with the air heat exchangers. The analysis indicates that the air heat exchangers cost is higher than the recycle blower cost by $45/kW on average. The difference is positive even after estimation errors are included. Hence, the baseline configuration will have a lower capital cost on a per-kW basis than the alternate configuration.

The baseline configuration is the preferred configuration despite its relatively lower efficiency compared to the alternate. The baseline system has a relatively lower initial capital cost on a per-kW basis than the alternate. Additionally, one of the most significant factors in the cost of electricity analysis of power plants is the plant's reliability. The baseline system is more reliable than the alternate system, as failure of one of the high temperature heat exchangers within the pressure vessel would be a reliability issue for the alternate. Standard practice for the baseline case would have "spare" recycle blowers available for quick changeover. In addition, the baseline configuration has the potential to be more cost effective by further optimization of the plant layout.

Similarly, the cost of the CO_2 isolation by direct O_2 combustion of the spent fuel stream is comparable within the ROM cost estimate to the Selexol plant. However, the Selexol plant has the potential for lower cost and better performance by integration of the Sulfur removal.

The capital cost is one of several inputs to the cost of electricity (COE). It should be noted that SOFC stacks are projected to have a replacement period of five years compared to 10 years or more for gasifiers and gas and steam turbines. Therefore, the overhaul and maintenance costs over the life of the plant are higher for the IGFC plant than those for the reference IGCC plant due to the high SOFC replacement costs. These aspects should be taken into consideration in arriving at the merits of the IGFC plant.

Table 7. ROM Initial Capital Cost Summary

	IGFC ROM Capital Cost Overview All in (1000's $, 2003)							
	IGCC Reference	IGCC Base	IGFC Baseline Air Recycle	IGFC Alternate Air Preheat	IGFC Baseline CO2 by Seloxol	IGFC Alternate CO2 by Seloxol	IGFC Baseline CO2 by O2 Burn	IGFC Alternate CO2 by O2 Burn
Basis Clean Syngas to AGR (lbs/hr)	542,691	254,190	253,045	253,045	253,045	253,045	253,045	253,045
Output (kW)	470,767	222,153	289,557	291,378	274,822	277,332	277,939	279,803
HHV Heat Rate (BTU/kWH)	8,421	8,359	6,384	6,344	6,726	6,665	6,651	6,606
Gasification process Capital Cost (K$)	534,917	292,248	290,970	290,970	290,970	290,970	299,970	299,970
Gasification process Capital Cost ($/kW)	1,136	1,316	1,005	999	1,059	1,049	1,079	1,072
GT+ST+HRSG Capital Cost (k$)	168,500	88,158	75,564	75,564	75,564	75,564	75,564	75,564
CC Contingency & Owner's Cost (k$)	44,230	23,141	19,835	19,835	19,835	19,835	19,835	19,835
Fuel Cell stack Capital Cost (k$)	n/a	n/a	**40,159**	**40,603**	**50,987**	**51,296**	**40,168**	**40,584**
Fuel Cell Integration System Capital Cost (k$)	n/a	n/a	**26,301**	**38,859**	**32,134**	**47,478**	**21,531**	**31,812**
Selexol System (K$)					**13,742**	**13,742**	**0**	**0**
Fuel loop Integartion(k$)					**28,082**	**28,082**	**58,798**	**58,798**
FC Contingency & Owner's Cost (k$)	n/a	n/a	26,168	29,581	43,707	47,815	38,084	40,891
Total Power Island Capital Cost (k$)	212,730	111,299	188,027	204,442	264,051	283,813	253,980	267,484
Total Power Island Capital Cost ($/kW)	452	501	649	702	961	1,023	914	956
Total Capital Cost (k$)	747,647	403,547	478,997	495,412	555,021	574,783	553,950	567,454
Total Capital Cost ($/kW)	**1,588**	**1,817**	**1,654**	**1,700**	**2,020**	**2,073**	**1,993**	**2,028**

4.7 Technology Gaps

It is not feasible, at present, to realize the plant concept presented in this report. Significant gaps exist in technology in certain areas, while in other areas, existing products must be extensively re-engineered to achieve the desired objectives. This section lists the gaps and the development requirements and concludes with recommendations for future work.

4.7.1 Gaps

Fuel Cells

- Size. The plant concept assumes reasonably large-sized cells (1500 cm^2). Large cells decrease the cell count in the plant, thereby improving reliability. It also mitigates effects like seal leakage, thereby improving overall performance. Cells currently produced are limited in size. Manufacturing large-sized planar cells could be a challenge.
- Fuel cell performance. The nominal design point for this study assumes a SOFC operating with a power density of 0.5 W/cm^2 at 80% fuel utilization and 0.7 Volts. This performance is also under typical shifted syngas composition. Practical cells meeting these objectives need development. No such planar cell presently exists with an area of 1500 cm^2. The plant concept assumes the SOFC can operate under pressures up to 12 bars.
- Staged SOFC concept. The plant design relies on the staged fuel cell concept for air management and cooling. Conceptually, this design is sound, but it has not been proven by testing.

Overall Plant

- Controls: The plant controls technology under various load conditions for such a large fuel cell plant does not exist. The various requirements of the Gasifier, Gas Clean Up system and the fuel cell modules need to be integrated to ensure proper plant operation. The analysis performed in the evaluation is limited to plant operation under steady state design point conditions.
- Plant Start Up and Shut Down: Specific sequence of operation for both plant start up and shut down needs to be developed.

Turbomachinery

- Low-Btu combustor. The spent fuel sent to the combustion chamber in the gas turbine has a relatively small heating value (~500 Btu/lb LHV). This is because a high percentage of the fuel is utilized in the fuel cell and electrochemically converted into steam. Combustor technology needs to be developed to burn this low-quality fuel.

4.7.2 Engineering developments

- Most of the plant layout surrounding the SOFC modules is novel and untested. Piping and plenums of similar size are found in other applications.
- No gas turbine presently exists with the particular combination of low pressure ratio, flow rate, and low firing temperature called for by this design. Additionally, this design requires 100% of the compressor air to be piped to the fuel cell modules before returning to the combustor and turbine. Engineering is needed to develop compressor and turbine plenums for 100% extraction with low pressure loss.
- The steam turbine in the bottoming cycle is relatively small (~20 MW). Commercial units of this class are available, but some engineering may be required to design a two-pressure reheat turbine of this size.
- No Selexol-based CO_2 capture plant has been built for this particular gas composition. The gas stream entering the Selexol plant is virtually free of sulfur and water, so it should be straightforward to engineer an optimized Selexol plant for this system.
- It is beyond the scope of this project to determine the final fate of the isolated CO_2. Technology that is being developed to inject CO_2 into oil wells, depleted natural gas wells, underground aquifers, and into oceans.
- The CO_2-lean fuel leaving the Selexol plant is almost completely dry. This is not a problem at the low temperature of the Selexol plant, but becomes a problem as the fuel is heated up to the fuel cell operating temperature. Steam must be added to the fuel to prevent carbon deposition in the recuperators and fuel preheaters. Technology to prevent carbon deposition has been developed and implemented in steam methane reformers.
- The spent fuel is sent to its own HRSG, separate from the HRSG for the exhaust air. The spent fuel is still pressurized (~65 psia) so the fuel HRSG must be contained in a pressurized shell. The product steam must be piped to the steam turbine, where it is combined with the steam generated from the air HRSG. Exhaust and re-heat steam must be bled off and returned to the fuel HRSG. Balancing the two HRSG cycles could be a difficult but feasible controls problem.
- If the alternate plant configuration outlined here is to be realized, then the high temperature, low pressure drop heat exchangers used inside the stack module should be engineered for size, cost, and reliability.

4.7.3 Recommendations for further work

- The power electronics design is outside the scope of this work. It is recognized that significant effort needs to go into designing the power electronics for these megawatt-sized SOFC modules.

- The overall plant startup can pose significant problems, and specific subsystems need to be engineered based on the startup strategy and controls requirement.
- The plant configuration outlined has significant volume and thermal inertia between the compressor and turbine, which is expected to have significant issues with plant controllability. This specific control technology needs to be developed.
- High temperature heat exchangers are among the most expensive components in the plant concept. Given their role in the realization of high efficiency SOFC power plants, ideas to make them more cost effective must be investigated.

5 CONCLUSION

The integration of a coal gasifier with a SOFC power generation system has been studied. The proposed plant concept includes an oxygen-blown gasifier system, a set of fuel cell modules, each containing several stacks, one or two large sized gas turbines, an HRSG, and a steam turbine. The possibility of CO_2 isolation from the exhaust products, either by an absorption method using Selexol or by pure O_2 combustion, has also been investigated. Rough Order of Magnitude (ROM) initial capital cost and net plant efficiencies were evaluated for all configurations.

Given the inherently high efficiency of SOFC modules, it is necessary to have the entire topping cycle consist of fuel cells. The spent fuel is then burned and the product expanded through large, high efficiency gas turbines. The gas turbine exhaust is then passed through the HRSG and a relatively small steam turbine for additional energy recovery. The CO_2 separation unit involves an additional HRSG with the spent fuel on the hot side and steam on the cold side. Most of the fuel cell exhaust is recycled and mixed with the shifted syngas before it is cooled and passed through the Selexol system for CO_2 absorption.

Various staging configurations were studied from a thermal management point of view. It was verified that maximum efficiency could be obtained from a staged, inter-cooled system of SOFC stacks. Various inter-cooling methods and associated cycle concepts were investigated. A baseline concept (with air recycle) and an alternate concept (air heat exchange) were downselected for further analysis. The alternate concept was found to have a slightly higher efficiency of 0.4% than the baseline. The ROM cost for the baseline configuration is lower by about $45/kW compared to the alternate configuration. The baseline configuration is the preferred configuration despite the 0.4% lower plant efficiency compared to the alternate configuration. The baseline system is more reliable than the alternate system, as failure of one of the high temperature heat exchangers within the pressure vessel could be a reliability issue for the alternate configuration. In addition, the baseline configuration has the potential to be more cost effective by further optimization of the plant layout.

Similarly, the cost of the CO_2 isolation by direct O_2 combustion of the spent fuel stream is comparable with in the ROM cost estimate to the Selexol plant. However, the Selexol plant may offer more flexibility for integration of the sulfur removal and elimination of the AGR.

Several technology gaps are recognized. Several areas needing significant engineering development work are also identified.

It has been shown that plant efficiency of approximately 53% is possible for the proposed baseline plant layout. The efficiency penalty for CO_2 isolation is about 2.5%. This projected penalty would be about 4% if the CO_2 has to be delivered at 1000 psia for sequestration purposes. ROM initial capital costs for this plant have been estimated to be on the order of $1700/kW for a plant without CO_2 isolation and $2000/kW with CO_2 isolation.

6 REFERENCES[DRK1]

EPRI, AFPS Developments, Gasification/Fuel Cell Study Projects [DRK2]Very Low Heat Rate, Winter 1990 Issue 6.

Farooque, M, G. Steinfeld, G. McCleary, and S. Kremenik, "Assessment of Coal Gasification/ Carbonate Fuel Cell Power Plants," Topical report to DOE/METC, June 1990, DOE/MC/23274-2911. NTIS/DE90015579.

Ghezel-Ayagh, H., R. Sanderson, and A. J. Leo, "Ultra High Efficiency Hybrid Direct Fuel Cell/Turbine Power Plant." Proceedings of Carbonate Fuel Cell Technology V, PV 99-20, Meeting of Electrochemical Society, Oct. 7-22, 1999, Hawaii.

Meyers S., "Advanced Molten Carbonate Fuel Cell Systems using BGL Gasification," presented at the 9th Annual Conference on Gasification Power Plants, October 16-19, 1990 Palo Alto, CA

[DRK3]Sander M.T., et al., Fluor Daniel, G.Steinfeld, Fuel Cell Energy , "Cost and Performance Analysis for a 220 MW phased Construction Carbonate Fuel Cell Power Plant", 11th Annual Conference on Gasification Power Plants, EPRI, October 1992

Sandler, H.S., and S.J Meyers, "Integrated Coal Gasification in Carbonate Fuel Cell Power Plants," 11th Annual Conference on Gasification Power Plants, EPRI , October 1992

Steinfeld, G., W. Willson "Advanced Power System Featuring a Closely Coupled Catalytic Gasification Carbonate Fuel Cell Plant," 17th Biennial Low rank Fuel Symposium, May 10-13, 1993, St. Louis, Missouri

[DRK4]Steinfeld, G., H. Ghezel-Ayagh, R.. Sanderson, S. Abens, "Integrated gasification fuel cell (IGFC) demonstration test"

[DRK5]U.S. DOE Office of Fossil Energy http://www.fe.doe.gov/programs/powersystems/gasification

U.S. DOE/EIA " Annual Energy Outlook 2000".

U.S. DOE/EIA " Annual Energy Review 2001".

[DRK1]These entries are in alphabetical order now. The superior numbers in the text have been removed and brief entries were substituted. I believe that these citations should include page numbers so that the reader of the report could easily check the accuracy of your quotw or paraphrase.

[DRK2]Is the capitalization right?

[DRK3]Even after we delete “Fluor Daniel, there’s still a problem. Please check.

[DRK4]Is this reference adequate?

[DRK5]Could these DOE references be made more specific? Is U.S. needed?

NETL F 510.1-5
(02/2002) OPI=CC01
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY

REQUEST FOR PATENT CLEARANCE FOR RELEASE OF CONTRACTED RESEARCH DOCUMENTS

TO: XX For Technical Reports
AAD Document Control
MS 921-143
U.S. Department of Energy - NETL
P.O. Box 10940
Pittsburgh, PA 15236-0940

☐ For Technical Papers/Journal Articles/Presentations
Mark P. Dvorscak
U.S. Department of Energy
9800 S. Cass Avenue
Argonne, IL 60439
FAX: (630) 252-2779

♦Award No. **DE-FC26-01NT40779**
Name & Phone No. of DOE COR **Norman Holcombe, 412.386.4557**

A. AWARDEE ACTION (AWARDEE COMPLETES PART A. 1-5)

1. Document Title: **Final Report (Topical) for Task 1A.4 "Coal Based System Study"**

2. Type of Document: ☐ Technical Progress Report XX Topical Report ☐ Final Technical Report

☐ Abstract ☐ Technical Paper ☐ Journal Article ☐ Conference Presentation

Other (please specify) ____________________

3. Date Clearance Needed: **1/31/2004**

♦4. Results of Review for Possible Inventive Subject Matter:

a. ☐ No Subject Invention is believed to be disclosed therein.

b. XX Describes a possible Subject Invention relating to ____________________

i. Awardee Docket No.: 147641, 148382

ii. A disclosure of the invention was submitted on Docket #141961 (S-103,736) submitted on 10/22/03

iii. A disclosure of the invention will be submitted by the following date: **2/27/2004 (for 147641 & 148382**

iv. A waiver of DOE's patent rights to the awardee: ☐ has been granted, XX has been applied for, or

☐ will be applied for by the following date: ____________________

♦5. Signed Raymond J. Andrews (Awardee) Date **1/31/2004**

Name & Phone No. **Raymond J. Andrews, 518.385.0336**

Address **GE Energy, Bldg 40-330T, 1 River Road, Schenectady, NY 12345**

B. DOE PATENT COUNSEL ACTION

☐ Patent clearance for release of the above-identified document is granted.

☐ Other: ____________________

Signed ____________________ Date ____________________
(Patent Attorney)

Must be completed by the awardee.