Assessing the Economic Potential of IGCC Innovation with Liquids Sparing

Final Report

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Executive Summary

The U.S. electricity sector is operating today under a number of uncertainties as power providers are forced to make significant long-term investments in the face of potential market structure reform, fundamental changes in fuel prices, and looming environmental regulations. In addition to these largely uncontrollable external forces, technological innovation is presenting a set of new options for investment that have the potential to facilitate a transformation in the industry by allowing it to increase reliance on the nation's most abundant energy resource – coal – in a manner that significantly improves the sector's environmental profile and enhances the nation's energy security objectives. But these nascent technologies come with a set of technological and financial risks that complicate the realization of their potential. This report examines a potential configuration for coal gasification leading to production of electricity (via integrated gasification combined cycle or IGCC) as a primary product, and liquid transportation fuels secondarily, and provides an assessment of the IGCC and coal gas to liquid (CGTL) technologies along with a comprehensive analysis of the economics under various financial structures.

In the U.S., almost any of the coal-fired options has an operating cost advantage over the natural gas-fired combined cycle because of the substantial fuel cost spread that prevails in current markets and is likely to continue in the foreseeable future. Consequently, coal-based plants can be assured of dispatch priority over natural gas and will operate whenever available. Therefore, plant availability is critical to their financial success. Uncertainties regarding the gasifier's ability to be available for an adequate portion of the operating schedule have resulted in cost premiums for those considering investing in these technologies. For the IGCC, the most relevant enhancement is to build a spare gasifier train which can eliminate the largest source of planned outages for refractory refurbishment and drive the overall plant availability into the 90+% range. An IGCC system consisting of three (2 plus 1 spare) gasifier trains and the necessary syngas to liquid fuel production facility can achieve 85 to 90% targeted availability for power generation and 85% availability for liquid fuel production assuming two year refractory life and 5% plant forced outage.

This study examines using a spare gasifier train as an operating unit to assure electrical output and using the surplus syngas after power generation needs have been met to produce marketable liquid fuels ("liquid sparing") to enhance revenues to the facility. The liquid fuels production technology incorporated into this study is the well-established Fischer-Tropsch (F-T) technology. The F-T technology is used to convert natural gas and syngas to liquid fuels and is available for license from Sasol, Rentech, Exxon, Shell, and others. Other options such as storing syngas to fire co-located peaking generation units might also be attractive should liquid prices drop. The key is to keep the capital equipment as productive as possible while assuring high system availability for power generation. This study also considers a number of ownership perspectives, each with different financing structures, financing costs, desired rate of return, and/or taxes obligations. The ownership perspectives considered include independent power producer (IPP), non-recourse financing; corporate owned, balance sheet financing; regulated investor-owned utility (IOU); and municipal-owned utility (MOU). Two forms of corporate-owned structures, leveraged corporate financing (LCF) and non-leveraged financing or Generating Company (GenCo) financing, are also evaluated.

This analysis indicates that:

A. At coal liquid prices of greater than $55 per barrel – equivalent to crude oil price of $44.40 per barrel (assuming a $10 per barrel premium for coal liquids in 2033 dollars) – IGCC with a spare gasifier for liquid production could be competitive with PC systems depending on the project financial structure. While at $55 per barrel, IGCC with liquid sparing could be competitive with PC systems, coal liquid prices of about $100 – equivalent to crude oil price of $89.40 per barrel is needed to make IGCC with liquid sparing competitive with PC system using a GenCO financing structure. The coal liquid prices needed for other financing structure considered; IOU, LCF, and IPP, falls in $55 - $100 per barrel rang.

B. At liquid prices of greater than $38 per barrel, MOU and IOU financing structures favor IGCC with liquid sparing to IGCC.

C. A reduction of about 20% in the capital costs will make IGCC with liquid sparing competitive with PC systems at liquid prices of about $38 per barrel under financing structures considered except for IPP financing.

D. At liquid prices of up to $50 per barrel, GenCo, LCF, and IPP financing structures favor IGCC without liquid sparing to IGCC with liquid sparing. A 10%-18% reduction in the capital cost of IGCC without liquid sparing will make this system competitive with PC. A reduction of 15% - 33% in the capital costs will be needed to make IGCC with sparing liquids competitive with PC systems at liquid prices of about $50 per barrel under GenCo, LCF, and IPP financing structures.

The production of liquid fuel from coal can enhance our national energy and economic security. However, at low coal liquid fuel (less than $55 per barrel) a larger coal to liquid plant than the one considered in this study should be considered to potentially take advantage of economy of scale. The size of liquid production plant in this study is relatively small as electric power is considered the primary product and the liquid fuel as a by-product. It may be more economic to produce liquid fuel as the primary product and utilize the resulting waste gas to produce electricity.

MOUs (and COOP's, who have a similar financing structure as MOUs) due to their lower cost of capital, tax exempt status, and the ability to spread the risk of the new plant over the entire system equity can overcome the additional capital cost of IGCC with “liquid sparing” at lower liquid fuel prices than other ownership/financing structures.

This analysis also indicates that capital cost reductions of up to 20% will make IGCC systems (with and without liquid sparing) competitive with PC systems under most financing structures.

Such a reduction in capital costs seems possible. Forecasts indicates that IGCC learning curve and economy-of-scale will reduce IGCC costs by 25-30% while PC costs can be reduced only by 10-15% as a result of supercritical technology.
Furthermore, repowering of old coal-fired plants could help to reduce capital costs:

A. Repowering provides an estimated 100-150$/kW advantage over green-field IGCC plants.

B. An off-the-books 250MW steam PC plant with 30-33% efficiency can be converted to a 750MW IGCC with 43-45% efficiency, using the existing steam turbine or similar size steam turbine.

Repowering of the existing coal-fired power plants that have reached their useful life provides an opportunity to lower capital costs, especially the project development costs. The existing coal-fired plants already have access to the needed infrastructure for coal transportation and handling, power evacuation and transmission lines, and water supply and transportation. The permitting and environmental approval could be facilitated by the fact that the existing plants are already permitted to use coal and utilizing IGCC technology would provide for a greater environmental performance than a PC boiler. Some of the existing equipment particularly, the steam turbines and their associated auxiliary equipment (feed water pumps, condensers, and generators) could potentially be integrated with the new IGCC system helping to reduce capital costs. Most power plants built during 1960-1980 could potentially be candidates for repowering with IGCC. These plants utilize steam turbines ranging from 250 MWe to 1100 MWe allowing for implementation of IGCC plants in 750 MWe to 33000 MWe range. Repowering of the existing coal power plants will preserve jobs associated with these facilities and would help to maintain the existing coal markets.

ASSESSING THE ECONOMIC POTENTIAL OF IGCC INNOVATION WITH LIQUIDS SPARING

1. INTRODUCTION

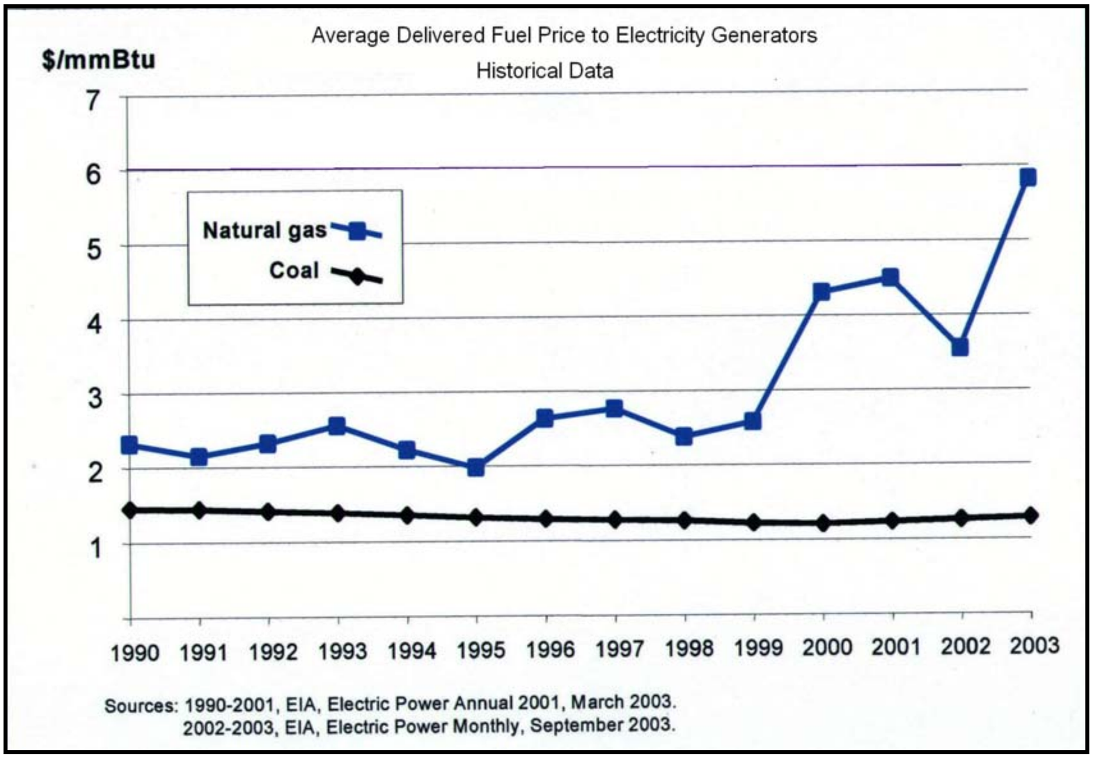
The U.S. electricity sector is operating today under a number of uncertainties as power providers are forced to make significant long-term investments in the face of potential market structure reform, fundamental changes in fuel prices, and looming environmental regulations. In addition to these largely uncontrollable external forces, technological innovation is presenting a set of new options for investment that have the potential to facilitate a transformation in the industry by allowing it to increase reliance on the nation's most abundant energy resource – coal – in a manner that significantly improves the sector's environmental profile and enhances the nation's energy security objectives. But these nascent technologies come with a set of technological and financial risks that complicate the realization of their potential. This report examines a potential configuration for coal gasification leading to production of electricity (via integrated gasification combined cycle or IGCC) as a primary product, and liquid transportation fuels secondarily, and provides an assessment of the IGCC and coal gas to liquid (CGTL) technologies along with a comprehensive analysis of the economics under various financial structures.

Following the boom in installations of natural gas fired combined cycle (NGCC) power plants during most of the 1990s, the U.S. has experienced a significant slowdown in the construction of new base load power generation facilities as the market has digested the impact of higher natural gas prices, a general overcapacity in most regions, and financial weakness in the sector. High prices for natural gas have forced many NGCC plant owners into default on their debt service obligations.[1] From December 2002 to January 2004, 15 merchant NGCC plants with a total capacity of more than 14 GW defaulted on their loans. In early 2004, Power Magazine reported that NGCC plants with a total capacity of about 33 GW or about 33% of the U.S. NGCC capacity could be classified as financially stressed.[2] High and volatile natural gas prices, particularly relative to coal (see Figure 1), have led to economically unacceptable dispatch rates for many NGCC plants which has resulted in a series of financial failures and asset foreclosures. Now, as demand finally catches up with this oversupply, developers are again considering investing in new power facilities. A new generation of coal plants – due to enormous domestic supplies and stable, low prices – is being seriously considered. Whether these investments are in traditional pulverized coal or next generation advanced technologies could have enormous implications for the nation's environmental and security future. In addition to entirely new projects, the aforementioned idle NGCC plants, due to technology overlap,

[1] SAIC, May 2004, *potential for NGCC Plant Conversion to a Coal-Based IGCC Plant – a Preliminary Study, Prepared for DOE/NETL.*

[2] Power Magazine, *Plethora of distress plants on markets puts industry-structure question on table,* Power Magazine, Feb. 19, 2004.

Figure 1 Average Delivered Fuel Prices



Note: Reproduced from Rosenburg, W.G., Walker, M.R., and Alpen, D.C., "Deploying IGCC in This Decade with 3-Party Covenant Financing," Harvard University, John F. Kennedy School of Government; July 2004.

could present an opportunity for converting equipment to IGCC at below market costs for the gas power generation package.

There are several potential competitors in the advanced coal electricity generation market place. This report focuses on technology for several reasons:

- Gasification technology allows for the production of power, chemicals, and liquid fuels. Ability to draw more on domestic energy reserves is considered a positive security benefit. The potential to utilize coal to offset petroleum consumption in the transportation sector is viewed as extremely important, given the emerging national security concerns surrounding U.S. reliance on foreign sources for the majority of its oil supplies.
- Gasification provides the most technologically robust and cost-effective process for capturing and collecting most of the input fuel's carbon before release into the atmosphere. As the nation and the world develop strategies to address the risks presented by global climate change, demonstrating this technology will certainly position the U.S. economy to better handle any mandatory CO_2 that may be imposed at some point in the future.
- Gasification has matured as a result of significant government investment in the U.S., Europe, and Japan as well as more than 60 years of experience with coal gasification to make syngas (CO plus hydrogen) for the synthesis of liquid fuels, complex organic chemicals, and fertilizers via well understood and reliable process designs (about 11,200

MW_t of coal syngas is accounted for by synfuels production in South Africa, 5,200 MW_t by plants that make ammonia and other chemicals in China, and 1,900 MW_t by the Dakota Gasification Company's Great Plains Synfuels Plant in the U.S. that makes synthetic natural gas and other byproducts).

- Gasification technology has gone through two generations of gasifier technology and is advancing rapidly on third generation designs[3] that are potentially more cost effective for power generation applications and more capable of handling low rank coals.
- The integration of coal gasification and combined cycle technologies has been demonstrated at commercial scale at five plants in the U.S., the Netherlands and Spain. Like their gas-fired combined cycle predecessors, these coal-fired IGCC plants went through some initial reliability/availability problems, which have been resolved slowly, yet effectively.

Currently, four commercial scale coal-based IGCC plants are operating worldwide; two in the U.S. and two in Europe. The plants in the U.S. are the 250 MWe Tampa Electric Polk Power station in Florida, which uses the ChevronTexaco (now GE Energy) technology, and the 260 MWe Wabash River repowering project in Terra Haute, Indiana, which utilizes a ConocoPhillips (formerly Dow) gasifier. The plants in Europe are the 350 MWe Elcogas plant in Spain and the 250 MWe Buggenum plant in the Netherlands, both utilize gasifier technology offered by Shell. These plants have been in entered commercial operation since the mid-1990s but were developed and partially financed in collaboration with public sector energy programs. The first large scale coal-based IGCC project in the U.S. was the 100 MWe Cool Water Project which was built and operated in the mid-1980s until oil and natural gas prices collapsed and NGCC became the technology of choice for thermal power generation in the U.S. and many other parts of the world. American Electric Power (AEP) has announced plans for construction of 1,200 MWe (2 plants each at 600 MWe) most likely in two different sites. Each plant will have three gasifier trains (2 plus 1 spare). According to AEP, the primary factors contributing to their decision includes (1) GE Energy's recent announcement that they will supply gasification equipment, as well as licensing and (2) the superior environmental performance of IGCC particularly with respect to carbon and mercury emissions. GE Energy's announcement has changed the market dynamics and now other gasification technology licensors are also planning to supply gasification technology equipment as well as licensing. Moreover, capital costs of PC power plants have risen in recent years and are projected to continue to rise as the result of ever-tightening environmental regulations.

In the U.S., almost any of the coal-fired options has an operating cost advantage over the natural gas-fired combined cycle because of the substantial fuel cost spread that prevails in current markets and is likely to continue in the foreseeable future. Consequently, coal-based plants can be assured of dispatch priority over natural gas and will operate whenever available. Therefore, plant availability is critical to their financial success. Uncertainties regarding the gasifier's ability to be available for an adequate portion of the operating schedule have resulted in cost premiums for those considering investing in these technologies (See Table 1 for a comparison of the coal-

[3] *The PSDF – A Key Step Towards Commercial Readiness for Coal Power* by Pinkston, Rodgers, and Rush, Southern Company Services and Weldon, EPRI, Clean Coal & Power Conference, Washington, D.C., December 2001.

based power generation technology costs). For the IGCC, the most relevant enhancement is to build a spare gasifier train which can eliminate the largest source of planned outages for refractory refurbishment and drive the overall plant availability into the 90+% range. An IGCC system consisting of three (2 plus 1 spare) gasifier trains and the necessary syngas to liquid fuel production facility can achieve 85 to 90% targeted availability for power generation and 85% availability for liquid fuel production assuming two year refractory life and 5% plant forced outage. Recent reports support this claim. Eastman Gasification Service Company, operating a ChevronTexaco (now GE) gasifier system for chemical production, has reported syngas availability of greater than 96% for 2001-2004, using a spare gasifier.[4] In a recent site visit to the Eastman facility, operators reported syngas availability of 96–98% and a single gasifier train availability of 92%.[5] The Buggenum plant has also reported availability of about 90%, the highest reported availability for a single train gasifier over a 10 month period of operation.[6] Although, a 10 month operating period may not be long enough to assess long-term availability, Shell has announced that it will guarantee 90% availability for the Shell gasifier. Further details on the nature of Shell's guarantee are not currently available.

Table 1 Coal-Based Power Generation Technology Costs

Study Source	IGCC				PC			
	Technology	Nominal Net Plant Size, (MW)	Total Plant Cost, ($/kW)	Total Capital Requirement, ($/kW)	Technology	Nominal Net Plant Size, (MW)	Total Plant Cost, ($/kW)	Total Capital Requirement, ($/kW)
EPRI, 2004	E-Gas (with Spare)	500 -550	1,350 - 1,440	1,490 – 1,710	Subcritical	500	1,230 – 1,290	1,430 – 1,150
National Coal Council, 2004	E-Gas (with Spare)	500	1,350	1,610	Subcritical	500	1,230	1,430
National Coal Council, 2004	E-Gas	500	1,250	1,490	Supercritical	500	1,290	1,490
EPRI, 2004	E-Gas	500 -550	1,250 - 1,330	1,490 – 1,580	Supercritical	500	1,290 – 1,340	1,490 – 1,550
EPRI/Parsons 2002	E-Gas	425	1,111	1,250	Supercritical	460	1,143	1,281
IEA Greenhouse Gas R&D Programme, 2003	Shell	776	1,287					
IEA Greenhouse Gas R&D Programme, 2003	Texaco	827	1,114					
NETL 2002	Shell	413	1,164	1,370	Subcritical	397	1,114	1,267
NETL 2002	E-Gas	401	1,167	1,374				

This study examines using a spare gasifier train as an operating unit to assure electrical output and using the surplus syngas after power generation needs have been met to produce marketable liquid fuels ("liquid sparing") to enhance revenues to the facility. The liquid fuels production technology incorporated into this study is the well-established Fischer-Tropsch (F-T) technology. The F-T technology is used to convert natural gas and syngas to liquid fuels and is available for license from Sasol, Rentech, Exxon, Shell, and others. Other options such as storing syngas to fire co-located peaking generation units might also be attractive should liquid prices drop. The key is to keep the capital equipment as productive as possible while assuring high system availability for power generation. Our baseline IGCC system does not include oxygen plant nitrogen re-injection into the gas turbine compressor discharge or other enhancements such as compressor inlet cooling/water injection to overcome gas turbine output degradation from high altitude or hot climate operation; nor does it include duct burning to increase steam cycle output.

[4] Moock, N., *"Update on Operations, Economic Improvement Opportunities,"* Gasification Technologies Conference 2004, Washington, DC, 3-6 October.
[5] Rezaiyan, J.; May 23, 2005.
[6] Gasification Technologies Conference 2004, Washington, DC, 3-6 October.

These enhancements could potentially reduce $/kWh generated due to improved system efficiency but would increase EPC costs. This study does not assign any emission credit sales or byproduct sales other than for liquid fuels and sulfur (i.e., nitrogen and argon form air separation units are vented and no credit is taken for mercury, NOx, SOx, CO_2, or particulates emission reductions) to the project annual revenue stream. On this basis, when comparing this economic assessment against more conventional coal-based technologies it should be noted that the results for IGCC are somewhat conservative as any future regulations on emissions (most importantly mercury or carbon) would enhance IGCC's position relative to other combustion based technologies.

This study considers a number of ownership perspectives, each with different financing structures, financing costs, desired rate of return, and/or taxes obligations. The ownership perspectives considered include independent power producer (IPP), non-recourse financing; corporate owned, balance sheet financing; regulated investor-owned utility (IOU); and municipal-owned utility (MOU). Two forms of corporate-owned structures, leveraged corporate financing (LCF) and non-leveraged financing or Generating Company (GenCo) financing, are also evaluated. Appendix A describes these ownership perspectives. A probabilistic model is used to assess the impact of changing key factors – such as input fuel and output product prices – on the overall probability of the project success. Probabilistic models are universally used by policy makers faced with decision making under uncertainty where material, equipment, and fuel costs, as well as currency values (which impact imported equipment and material costs) can vary in unpredictable ways due to market and economic conditions. Using probabilistic models allows for decision making in such an environment of unpredictability.

2. F-T TECHNOLOGY

Neither coal gasification nor F-T technology is new. Over 100 gasifiers are currently operating commercially, mostly in China, producing syngas for use in the chemical and fertilizer industries. Coal-derived syngas is also used to produce liquid fuels through the F-T process, which is a well established commercial technology. Sasol in South Africa has extensive construction and operating experience with F-T technology and annually converts about 51 million tons of coal into about 1.58 billion gallons of synthetic fuels and 528 million gallons of chemicals.[7]

The major challenge in producing liquid fuel from coal is to increase the hydrogen to carbon ratio on a molecular basis (H/C). As a point of reference, the H/C ratio for gasoline and diesel is about 2, the ratio for typical crude oil is 1.3-1.9, and for typical bituminous coal, 0.8. F-T technology and other indirect coal liquefaction technologies such as LPMEOH™ and LPDME™ processes (Air Products) for production of methanol and dimethyl ether rely on first gasifying the coal to produce syngas. The H/C ratio is then adjusted, as needed, using the water-gas-shift reaction (shown below) and by removing the CO_2.

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

[7] Greetsema, A., 1996. "*Synthesis gas to fuels and chemicals",* Fifth China-Japan Symposium on Coal and C1 Chemistry, Hungshan, China.

The CO and H_2 molecules are then catalytically combined to produce synthetic fuel containing primarily diesel or gasoline by F-T processes or oxygenated fuel using LPMEOH™ or LPDME™ processes.

The F-T process operates in two temperature regimes, high and low. The high temperature (570^{o}F - 625^{o}F) processes convert CO and H_2 to a liquid fuel consisting predominantly of gasoline and light olefins (ethylene, propylene, pentene, etc.). The liquid fuel is further processed to separate gasoline and olefins. Olefins are sold to polymer industry or are converted to diesel fuel. The high temperature reaction can be represented as:

$n\,CO + 2_n\,H_2 \rightarrow n\,H_2O + C_nH_{2n}$ where n represents the number of CO molecules.

The low-temperature (390^{o}F - 445^{o}F) F-T processes convert CO and H_2 to a liquid fuel which can easily be converted to a predominantly high quality diesel. The low-temperature reaction can be show as:

$n\,CO + (2_n + 1)\,H_2 \rightarrow n\,H_2O + CnH_{2n+2}$

Both, the low- and high-temperature processes are exothermic and heat must be removed from the reactor vessel to maintain the desired reactor temperature. Sasol, Shell, BP, Rentech, Sasol Chevron, and others supply proprietary F-T technology; most use a slurry-phase reactor with a cobalt- or iron-based catalyst. Shell and BP use a fixed reactor. Sasol uses iron-based catalysts and now offers fluidized-bed reactors for high-temperature and slurry phase reactors instead of the original circulating and fixed bed reactors respectively for high and low temperature processes. Typical Sasol's high-temperature reactors are 26-36 feet in diameter and about 125 feet high and produce up to 20,000 barrel per day per reactor. The low temperature reactors are typically about 16.5 feet in diameter and 72 feet high and produce about 2,500 barrel per day of F-T liquids. Figure 1 presents a typical flowsheet for F-T process.

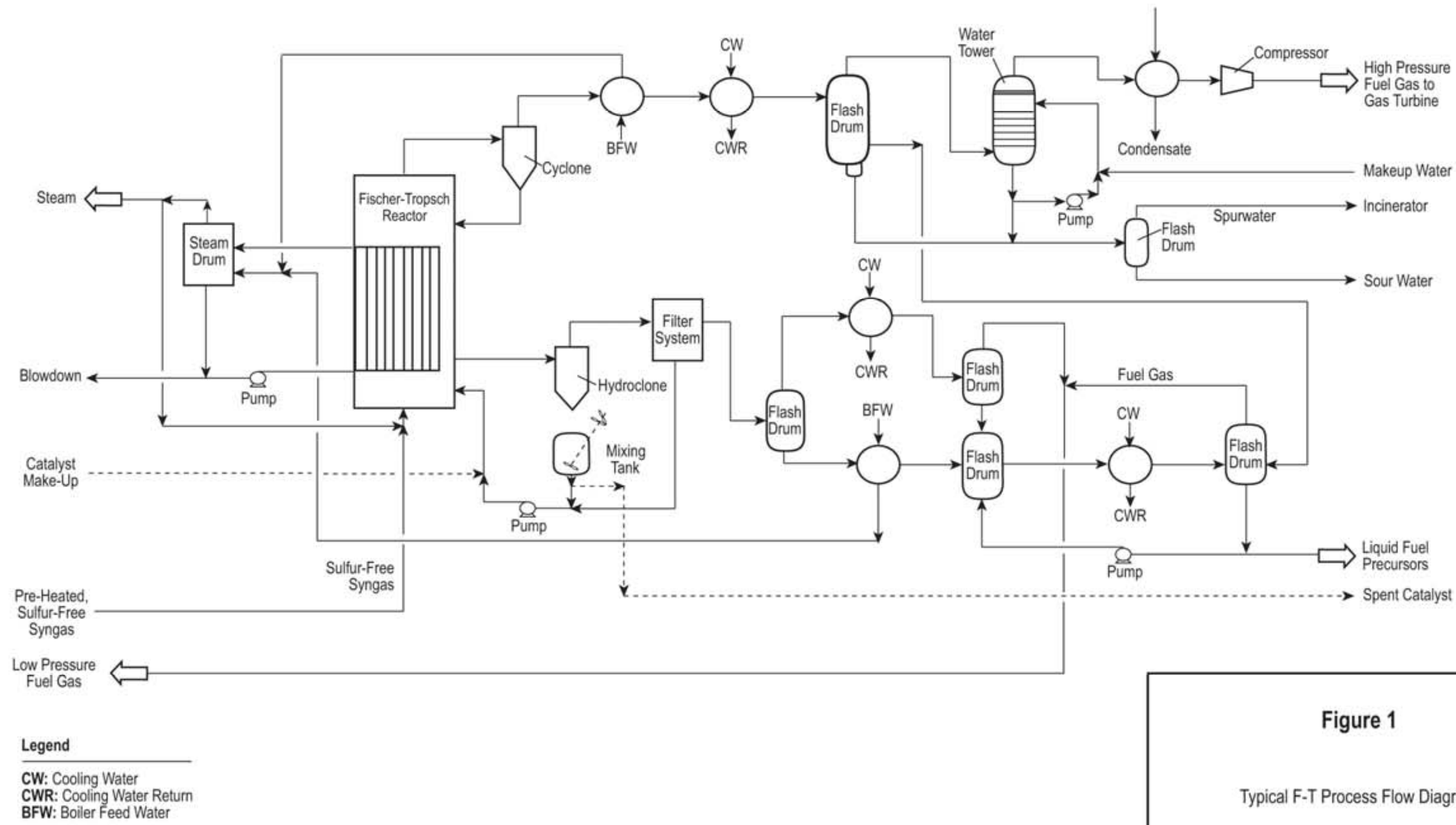


Figure 1

Typical F-T Process Flow Diagram

Roughly 75% of a barrel of high-temperature F-T liquid can easily be converted to transportation fuel (diesel, gasoline, jet fuel) which is about the same that can be produced from a barrel of Venezuelan crude by "deep" refining. Without deep refining only 15 – 25% of a barrel of Venezuelan crude can be converted to diesel fuel. In contrast, low-temperature F-T liquid is about 75% diesel. The avoidance cost of "deep" refining allows F-T liquids to demand a premium price. This premium price was estimated to be as high as $10 per barrel of equivalent crude oil prices (a 50% premium) in 2003, depending on the refinery configuration and relative demand for refined products.[8] *Annual Energy Outlook* reports current average oil prices to be $33.99 per barrel (at 2003 constant dollars) and projects prices to drop to $25.00 per barrel by 2010 and then increase to about $33.31 per barrel by 2025.[9] Assuming an annual inflation rate of 3%, average oil prices are $36.06 per barrel for 2005, $30.75 for 2010, and $65.13 for 2025 (in nominal dollars). Thus, F-T liquid prices could range from a low of $41.36 to a high of $84.29 per barrel (in nominal dollars) over the next 20 years. The *Annual Energy Outlook* average crude oil prices for 2005 are lower than current spot market prices because they represent prices at which market is in equilibrium (i.e., necessary market adjustments are made so supply is equal to demand) and not reflective of market dynamics at a given time. It should also be noted that the premium price for light crude and/or F-T liquids is expected to increase as demand for the refined products increases in countries with economies in transition such as China and India. Furthermore, light crude is not as readily available as it was a decade ago, and there are few refineries in the U.S. that are designed to process heavy crude oils and even fewer that are designed to process heavy crud oils such as those being imported from Venezuela.

3. BENEFITS OF IGCC TECHNOLOGY WITH LIQUID SPARING

A PC plant with proper emission controls may approach IGCC performance in one or two areas, but it cannot match IGCC's overall environmental performance including air, water, and solids emissions.[10] EPRI reports[11] that "a state-of-the-art IGCC with enhanced sulfur removal technology can simultaneously achieve greater than 99.5% sulfur removal, essentially total volatile mercury removal (greater than 90 – 95% removal), and PM levels of <0.004 lb/MBtu. The state of the art IGCC plant will also produce only 40% as many solids byproducts as coal combustion processes, and will use almost 40% less total water." If environmental policy involves trading in pollutants and contaminants, that superior performance will be recognized in annual revenues that could be substantial, depending on the trading market conditions. Furthermore, existing commercially available IGCC technologies have a thermal efficiency of about 40%, while the average thermal efficiency of existing PC plants is less than 34%. Even the most advanced PC plants, ultrasupercritical PC plants, have efficiencies in the range of 46 - 48%, while advanced IGCC plants are capable of reaching efficiencies of up to 50%. It should also be noted that there is not an operating ultrasupercritical PC plant in the U.S. and the prior experience with that technology in the U.S. has not been favorable. In addition, co-producing

[8] Williams, R. and Larson, E. "*A comparison of direct and indirect liquefaction technologies for making fluid fuels from coal,*" Energy for Sustainable Development, Volume VII, No. 4, December 2003.
[9] 2005 Annual Energy Outlook, December 2004.
[10] Booras, G. and Holt, N.,*"Pulverized Coal and IGCC Plant Cost and Performance Estimates,"* Gasification Technologies Conference 2004, Washington, DC, 3-6 October.
[11] See reference 4, page 7.

power and liquid fuels can increase IGCC plant thermal efficiencies to greater than 50%.[12] Not only can IGCC meet future environmental challenges to coal utilization but it can also provide the nation with fuel flexibility and enhance energy security. Co-producing liquids can enhance the nation's energy security by reducing reliance on imported liquid fuels and increasing use of domestic energy resources.

The National Commission on Energy Policy (NCEP) proposed a 10 GW IGCC demonstration program. While not requiring liquids sparing in these units, doing so could produce 57,981 barrels per day of liquids, assuming our baseline IGCC plant design with sparing liquids production produces 3,200 barrels per day at 85% capacity factor (or 3,766 barrels per day at 100% capacity factor) of high grade low sulfur FT liquids for a 552MWe (net) electricity generation plant. As noted earlier, a barrel of (high-temperature) F-T liquids can produce at minimum as much transportation fuel as a barrel of Venezuelan crude, or about 0.75 barrels of transportation fuel (diesel, jet fuel, and gasoline), assuming the Venezuelan crude is processed in a "deep" refinery. In the absence of deep refining of the Venezuelan crude, a barrel of (low-temperature) F-T liquid produces at least 3 times more diesel fuel than a barrel of Venezuelan crude. Thus, depending on the final transportation fuel desired, the 10 GW demonstration program could effectively displace up to 173,943 barrels per day of oil for an additional 110,708 tons per day of U.S. coal in 2020. This would offset 0.9% of expected crude oil demand in 2020. (The10 GW will come online over the course of a decade by 2020).

An Energy Information Administration (EIA) study[13] shows that the NCE P-proposed 10 GW IGCC demonstration program could stimulate cost reductions that would lead to deployment of 21 additional gigawatts of IGCC capacity. This study did not consider the impact due to such additional market penetration on liquid sparing potential, coal-liquid costs or, economics, or IGCC system with liquid sparing competitiveness.

4. DESIGN, COSTS, AND ECONOMIC ASSUMPTIONS

The energy and material balances as well as IGCC plant design and EPC costs are extrapolated from a study conducted by the National Energy Technology Laboratory (NETL).[14] The design basis for this study is summarized in Table 2.

NETL conducted a detailed study from 1999-2003 to optimize costs and performance of IGCC plants, based on the ConocoPhillips (then Global Energy) gasification technology, for co-production of electricity and hydrogen or liquid fuel using coke and coal as feedstocks. The NETL study was used as the basis for estimating plant installed costs and electricity, liquid fuel, and sulfur production as well as coal consumption for the power only and power plus liquid fuel IGCC scenarios evaluated in PERI's study. The primary differences between the two studies are that:

[12] United States Department of Energy National Energy Technology Laboratory, *"Gasification Plant Cost and Performance Optimization – Task 1 &2 Topical Reports,"* prepared by Bechtel, Global Energy, and Nexant, September 2003 (Contract No. DE-AC26-99FT40342).
[13] Impacts of Modeled Recommendations of the National Commission on Energy Policy, EIA, April 205.
[14] See reference No. 6.

- NETL power-only IGCC scenarios were optimized using natural gas as back-up fuel, while PERI's study assumes a spare gasifier is available to meet combustion turbine demand for gas (See Figure 2).

Table 2 Design Basis

	PC Plant	IGCC Plant Without Spare Gasifier	IGCC Plant With Spare Gasifier
Design Capacity, MWe	550	577	627
Auxiliary Power, MWe	55	66	75
Net Capacity, MWe	495	511	552
Liquid Fuel Production, bpd	0	0	3,766
Sulfur Production, tpd	0	118	199
Coal Consumption, tpd	5,467	4,793	7,189
Average Plant Efficiency, %	34	40	42
Number of Boilers/Gasifiers	1	2	3

- NETL power and liquid fuel IGCC scenarios were optimized by maximizing liquid fuel production, while PERI's study assumes only syngas that is not utilized by the combustion turbine to meet IGCC plant availability for power generation is converted to liquid fuel (See Figure 3).
- PERI's study does not attempt to optimize plant configuration or economics. It attempts to establish the relative economic impact of IGCC plant configuration by maximizing plant availability for power generation using a spare gasifier and converting any excess syngas to liquid fuels assuming different financing structures.

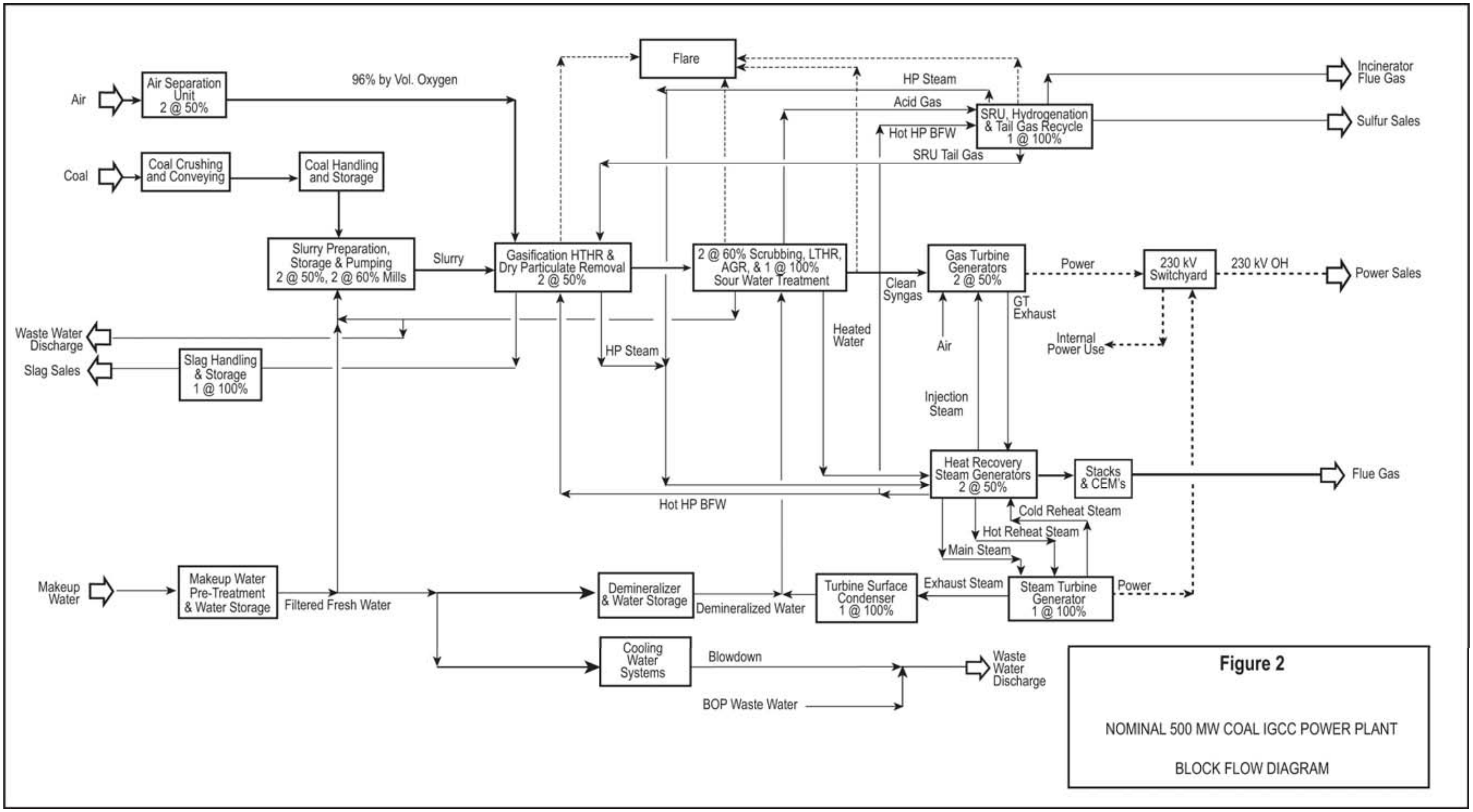


Figure 2

NOMINAL 500 MW COAL IGCC POWER PLANT

BLOCK FLOW DIAGRAM

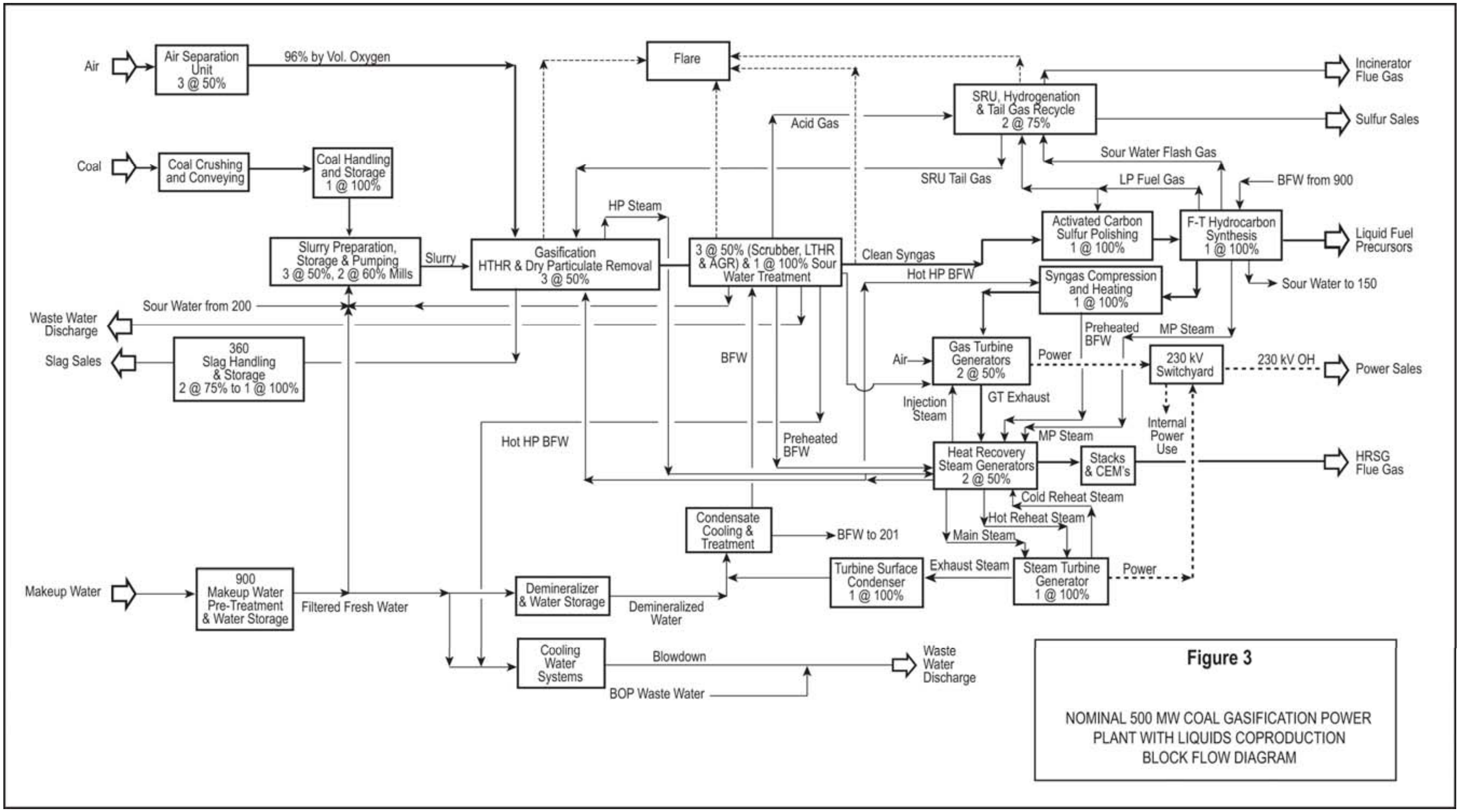


Figure 3

NOMINAL 500 MW COAL GASIFICATION POWER PLANT WITH LIQUIDS COPRODUCTION BLOCK FLOW DIAGRAM

After establishing estimated EPC costs, PERI used in-house cost factors to develop the total plant capital costs. For PC plants, an installed plant cost of $1,240 per kWe was assumed. Interest during construction (IDC) was estimated assuming a four year construction period with funds dispersed in four equal amounts. Table 3 summarizes EPC and soft costs, interest during construction, and total capital costs.

Next, operation and maintenance costs were estimated using in-house cost data, confidential sources[15], and published data.[16, 17] The operation and maintenance costs are presented in Table 4.

Finally, simplified spreadsheet financial models were used to estimate tariff and/or internal rates of return on equity (IRR) from various ownership perspectives. Tariff is the price that a power generator must charge for electricity in order to recover all of its operating costs and meet its financial obligations to local and federal governments, lenders, and equity share holders. It decreases (in constant dollars) over time as the debt is retired and varies depending on the financing structure of the project. In some instances, the arithmetic average of the annual tariffs over the life of the project is used to simplify the presentation of the results. The IRR is the interest rate corresponding to a net present value of annual net cash flows over the life of the plant that equals the equity investment amount.

As presented in Table 3, the estimated EPC costs for IGCC plant without a spare gasifier train are $1,673/kWe with a total capital cost of $1,962 to $2,229/kWe depending on the project financing structure. For comparison purposes and as indication of the reasonableness of the EPC costs used in this study the following actual project costs were considered:

- The construction cost of the Polk IGCC is reported to be about $2,000/kWe exclusive of the U.S. Department of Energy (DOE) funding. Today's direct costs of a new single train 250 MW IGCC plant on the Polk site, incorporating all the lessons learned is estimated to be $1,650/kWe. A new plant build with economies of scale could reduce the capital costs to $1,300/kWe or less.[18]

- The estimated total cost for the 285 MWe Southern Company IGCC project which recently received a DOE award, is $1,950/KWe. The U.S. DOE is contributing $235 million for construction and operation of this advanced power plant which utilizes a third generation gasifier. Without DOE's support, project soft costs (financing fees, initial working capital, contingency, and other costs such as legal and permitting costs that are not included in EPC costs) and therefore the total capital cost, would be higher for this first-of-a-kind plant. However, Southern Company has suggested in a comparative cost

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[15] Rezaiyan, A. J., confidential e-mail correspondence, March 31, 2005.

[16] Williams, R. H. and Larson, E.D. *"A comparison of direct and indirect liquefaction technologies for making fuels from coal,"* Energy for Sustainable Development, Volume VII No. 4, December 2003.

[17] Booras, G. and Holt, N., *"Pulverized Coal and IGCC Plant Cost and Performance Estimates,"* Gasification Technologies Conference 2004, Washington, DC, 3-6 October.

[18] Charles M. Black, V.P. Operations, Tampa Electric Co., Testimony before the U.S. House of Representative Subcommittee on Energy and Air Quality, June 2003.

study[19] of its Transport Reactor Integrated Gasification Combine Cycle (TRIGCC) technology, that a 20% reduction would be expected in going from a first-of-a-kind 300MWe scale to a 400MWe scale Nth plant (Figure 4). It should be noted that the total plant costs in Figure 4 are exclusive of plant start-up and interest during construction. Figure 4 also shows expected heat rate and efficiency (η) improvements the first, second and Nth plants.

- The Excelsior Energy 531 MWe Mesaba IGCC project is estimated to cost about \$2,220/kWe. The project utilizes a second generation gasifier and incorporates results from technology studies and lessons learned at the Wabash River IGCC power project and other DOE funded studies. In addition, the project has received \$35 million of funding from the U.S. DOE and \$10 million from Xcel Energy's Renewable Fund.

Table 4 compares the operating costs for the three systems under consideration. The total variable operation and maintenance (O&M) cost - fuel cost plus variable O&M cost - is an important consideration for dispatching a plant. The total variable O&M cost for IGCC system is less than the PC system's total O&M costs, primarily due to the IGCC system's higher efficiency.

Table 5 lists economic assumptions for different financing structures. Delivered prices for Illinois No. 6 coal is assumed to be \$25 per ton, while coal liquid and sulfur prices are assumed to be \$38 per barrel (bbl) and \$40 per ton. The assumed coal liquid price of \$38 per barrel is some what conservative considering current crude oil market spot prices of about \$55 per barrel. Sensitivity analyses are performed to assess the impact of changes or uncertainties in coal prices, liquid fuel prices, and construction cost on the electricity prices (tariff) and/or IRR. It is important to remember (as discussed above) that that the value of coal liquids is substantially higher than the value of crude oils, since they are partially refined and could attract up to 50% premium over crude oil prices.

[19] Pinkston, T.; Roger, L.; Rush, R.; and Wheeldon, J.; "*The PSDF – A Key Step Towards Commercial Readiness For Coal Power,*" Clean Coal & Power Conference, Washington, DC, 2001

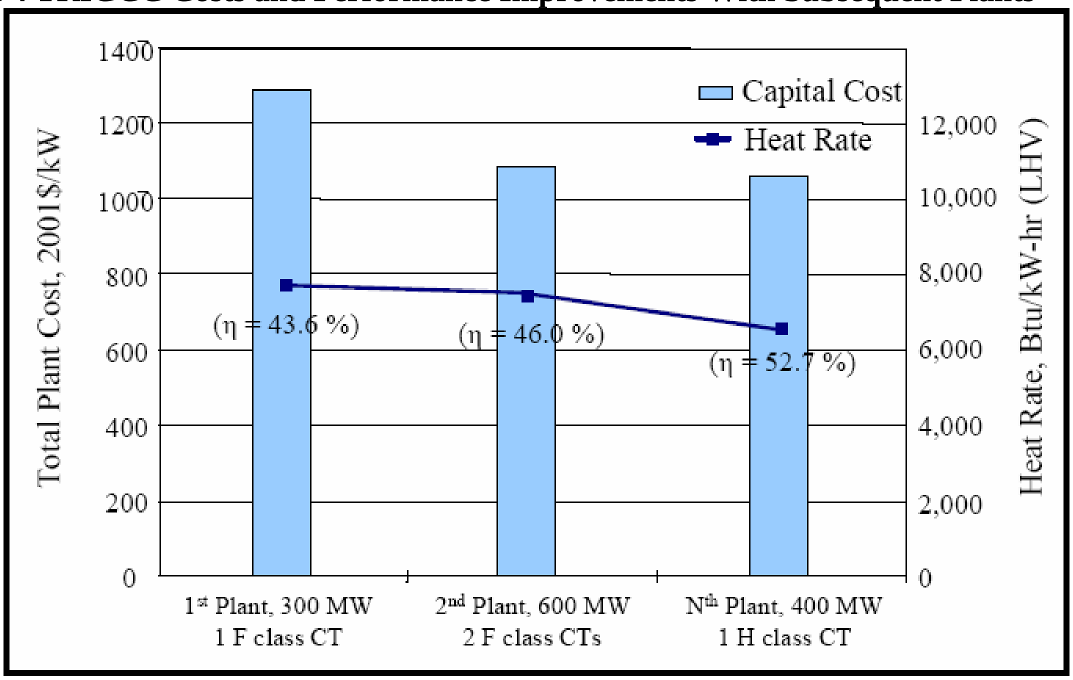
Table 3 Capital Costs

	PC Plant		IGCC Without Spare Gasifier		IGCC With Spare Gasifier	
	Non-Recourse Financing (IPP)	Leveraged Corporate, GenCo, IOU, and MOU Financing	Non-Recourse Financing (IPP)	Leveraged Corporate, GenCo, IOU, and MOU Financing	Non-Recourse Financing (IPP)	Leveraged Corporate, GenCo, IOU, and MOU Financing
1. EPC Cost (2+3)	**$692,230,000**	**$692,230,000**	**$965,413,000**	**$965,413,000**	**$1,239,689,000**	**$1,239,689,000**
2. Installed Cost	$682,000,000	$682,000,000	$951,146,000	$951,146,000	$1,221,368,000	$1,221,368,000
3. Start-Up Cost	$10,230,000	$10,230,000	$14,267,000	$14,267,000	$18,321,000	$18,321,000
4. Soft Costs (5+6+7+8)	**$152,809,000**	**$48,475,000**	**$200,717,000**	**$68,504,000**	**$256,390,000**	**$88,221,000**
5. Financing Fees	$22,093,000		$27,707,000		$35,169,000	
6. Initial Working Capital	$19,503,000		$20,420,000		$27,978,000	
7. Contingency	$75,889,000		$104,730,000		$134,371,000	
8. Other Costs	$35,324,000		$47,860,000		$58,872,000	
9. Interest During Construction	**$88,900,000**	**$71,200,000**	**$120,300,000**	**$98,400,000**	**$153,800,000**	**$126,100,000**
Total Capital Cost (1+4+9)	**$933,939,000**	**$811,905,000**	**$1,286,430,000**	**$1,132,317,000**	**$1,649,879,000**	**$1,454,010,000**
EPC Cost, $/kW	**1258**	**1258**	**1673**	**1673**	**1977**	**1977**
Soft Costs, $/kW	**278**	**88**	**348**	**119**	**409**	**141**
Interest During Construction, $/kW	**162**	**129**	**208**	**170**	**245**	**201**
Total Capital Costs, $/kW	**1698**	**1475**	**2229**	**1962**	**2631**	**2319**

Table 4 Operating Costs

	PC Plant	IGCC Without Spare Gasifier	IGCC With Spare Gasifier
1. O&M Expenses (4% of Installed Cost)	$27,280,000	$38,046,000	$48,855,000
2. Insurance (1% of Installed Cost)	$6,820,000	$9,511,000	$12,213,000
3. Maintenance Fee for Loan (Through Year 15)	$10,000	$10,000	$10,000
Total Operating Expenses (1+2+3)	**$34,110,000**	**$47,567,000**	**$61,078,000**
Power/Liquid Production Availability, %	88 / Zero	88 / Zero	88 / 85
Fixed O&M Costs, $/MWh	7.36	10.87	13.20
Variable (excluding coal) O&M Costs, $/MWh	1.57	1.2	1.15
Liquid Fuel/Sulfur Credit, $/MWh	0	(0.38)	(11.02)
Net Variable O&M Cost, $/MWh	1.57	0.82	(9.87)
Coal Cost, $/MWh	11.50	9.77	13.41
Total Variable O&M Cost, $/MWh	**13.07**	**10.59**	**3.54**

Figure 4 TRIGCC Costs and Performance Improvements With Subsequent Plants[20]



[20] Reproduced from Pinkston, T.; Roger, L.; Rush, R.; and Wheeldon, J.; "*The PSDF – A Key Step Towards Commercial Readiness For Coal Power,*" Clean Coal & Power Conference, Washington, DC, 2001

Table 5 Economic Assumptions

	Non-Recourse Financing (IPP)	Leveraged Corporate Financing	GenCo Financing	IOU Financing	MOU Financing
Interest on Debt, %	8	6	6	6	5
Term, Year	20	20	20	30	30
Debt Service Reserve	6 months	None	None	None	None
Interest on Debt Service Reserve, %	5	None	None	None	None
Debt, % total capital	70	80	35	47	100
Equity, % total capital	30	20	65	53	0
Plant Life, year	20	20	20	30	30
Depreciation, Year/ Method	20/ Straight Line	20/ Straight Line	20/ Straight Line	6/ Accelerated	6/ Accelerated
Income Tax	38%	38%	38%	38%	None
Inflation	None	None	None	None	None
IRR (Equity), %	**12**	**12**	**12**	**None**	**None**
Annual Return of Stock					
Preferred Stock	None	None	None	5.50%	None
Common Stock	None	None	None	9.00%	None

5. RESULTS

5.1 Comparative Analysis

Figure 5 shows calculated tariff values (in real term) over the life of the three different plants (PC and IGCC with and without spare gasifier) for different project ownership or financing structure using capital costs, O&M costs, and economic assumptions presented in Tables 2, 3, and 4. The tariff profile over the life of a project varies depending on the financing structure and applicable tax laws. Different approaches (i.e., declining, increasing, and constant) are usually used to smooth the step changes in tariff while maintaining the desired IRR. However, it is difficult to compare an array of tariffs through 20 – 30 years of plant life for different plant types using different financing structures. In this section, the most commonly used value namely levelized tariff, is used for comparative analysis purposes.

Figure 6 compares the estimated levelized tariff over the life of the plant for PC and IGCC plants with and without a spare gasifier for different financing structures assuming $38 per barrel and $50 per barrel for F-T liquids. It indicates that the most favorable financing structure for financing IGCC plants, particularly IGCC plants with a spare gasifier is MOU, while the least favorable is GenCo. It could also be argued that customers of MOUs benefit most directly from improved environmental attributes of IGCC plants (i.e., improved air quality and lower health costs, etc.) and therefore municipalities are in a better position to support financing of IGCC projects.

Figure 7 shows that at F-T liquid prices of greater than $55 per barrel, an IGCC plant with three (2 plus 1 spare) gasifier trains, 88% availability for power generation, and 85% availability for liquid production could be competitive with a PC plant. As noted earlier, a price range of $40 - $65 per barrel is likely, assuming only a $10 per barrel premium.

Table 6 shows the gap between IGCC and PC systems' tariff. The tariff for IGCC without liquid sparing is 8 - 17% higher than the PC's tariff and for IGCC with liquid sparing it is 3 - 20% higher depending on the liquid fuel prices. Table 6 also indicates that under current cost and economic assumptions, the MOU financing structure favors the addition of liquid sparing due to its lower financing costs and tax exempt status. However, it should also be noted that equalizing the tariff or rate of return does not eliminate all of the risks associated with IGCC systems. The comparative risks or probability of success of IGCC and PC systems are presented in the next section of this report.

Principal and interest payments, return on equity and taxes account for about 72% of the IGCC's tariff for GenCo financing and for about 45% of the tariff for MOU financing cases. This suggests that reducing capital costs (and thus, principal and interest payment) and reducing taxes may have the greatest impact on enhancing market acceptance of IGCC systems.

Figure 8 shows the approximate reduction in IGCC systems costs that would make them competitive with PC systems under different financing schemes. This figure also show the impact of increased liquid fuel prices on relative capital cost reductions and tariff of IGCC systems with liquid sparing. Figure 8 shows that:

- Approximately a 10% reduction in the capital costs of IGCC with spare gasifier would make IGCC competitive with PC under GenCo and LCF financing structures,while capital cost reductions of about 17%, 23%, and 28% would be needed respectively for IPP, IOU, and MOU financing structures.

- Depending on the liquid fuel prices, a 6-20% reduction in the capital costs of IGCC with liquid sparing would make that system competitive with PC systems. Capital cost reduction of 15 – 23% would make IGCC with liquid sparing competitive with PC at liquid fuel prices of $38 - $50 per barrel for IOU, GenCo, LCF financed projects, while IPP's will require capital cost reductions of 26 - 35% at the same fuel cost range.

Figure 5 Tariff Comparison for Different Project Ownership Structures

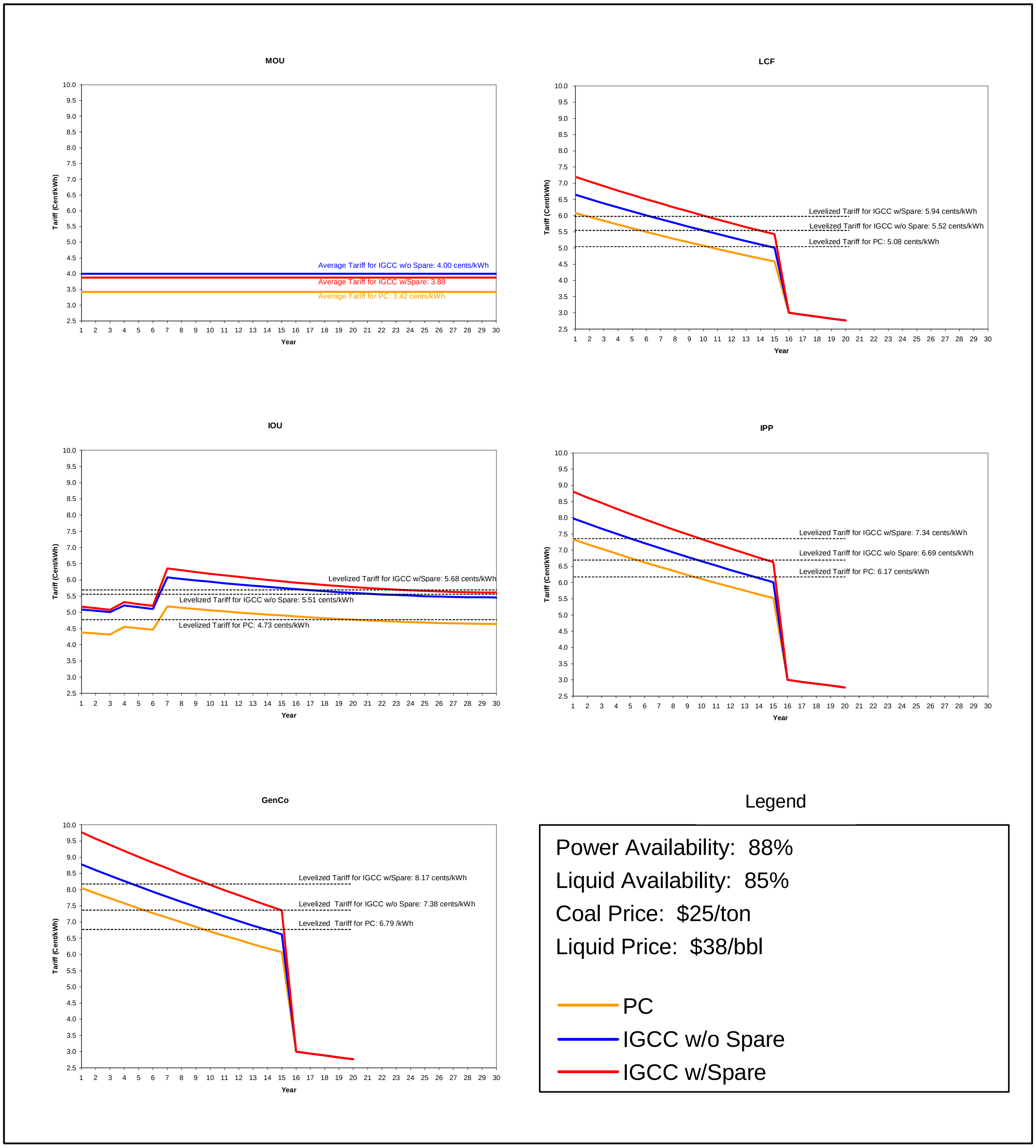
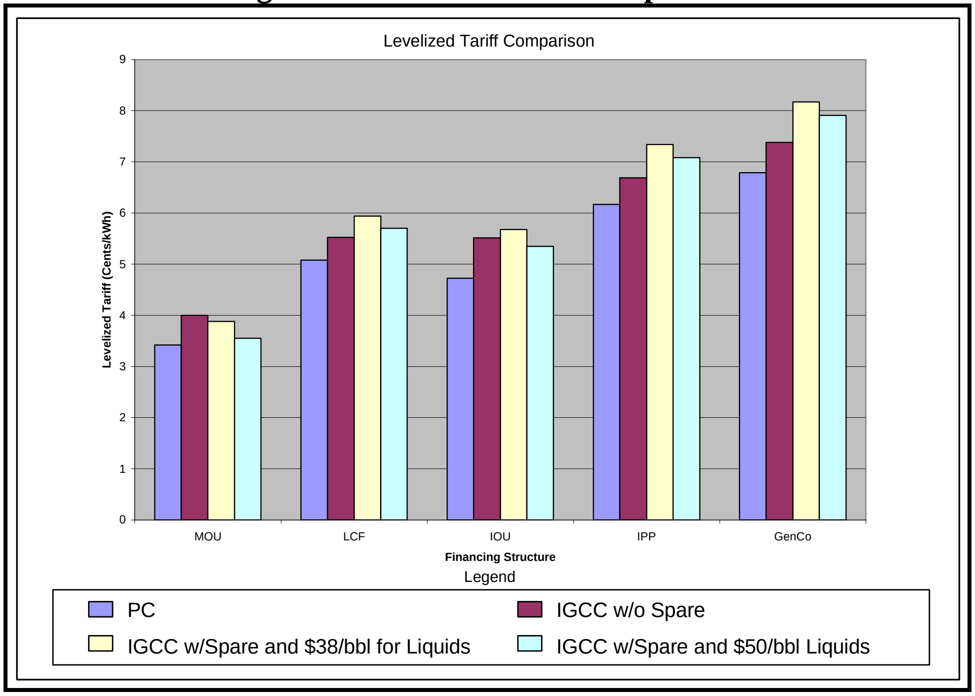
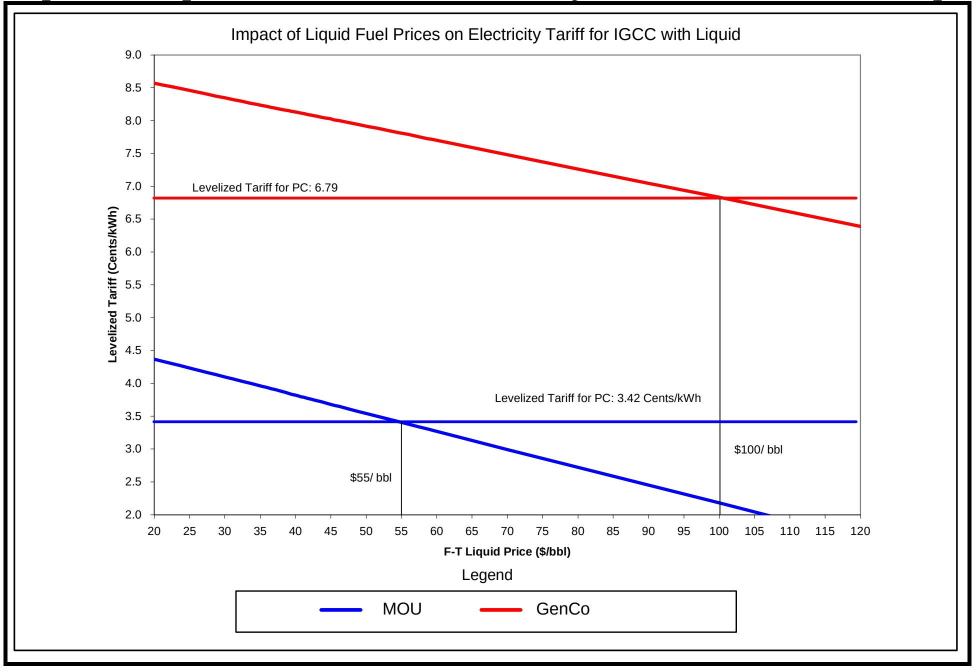


Figure 6 Levelized Tariff Comparison



Note: Assumes 88% availability for PC and IGCC without spare, 88% power availability and 85% liquid production availability for IGCC with spare gasifier, $25 per ton for coal.

Figure 7 Impact of Liquid Fuel Prices on Electricity Tariff for IGCC with Liquid Sparing



Note: Assumes 88% availability for PC and IGCC without spare, 88% power availability and 85% liquid production availability for IGCC with spare gasifier, $25 per ton for coal.

Table 6 Average Tariff Gap Between IGCC and PC Systems

Financing Structure	IGCC Without Liquid Sparing ($/MWh)	IGCC With Liquid Sparing ($/MWh)	
		$38/bbl	**$50/bbl**
MOU	5.8	**4.6**	**1.3**
Leveraged Corporate Financing	4.4	8.6	6.2
IOU	7.8	9.5	6.2
IPP	5.2	11.7	9.1
GenCo	5.9	13.8	11.2

Note: Assumes coal price of $26 per ton.

Figure 9 shows the sensitivity of the levelized tariff to coal prices. Tariff generally decreases with lower coal prices, however it decreases faster for IGCC with liquid sparing than IGCC without liquid sparing. In other words, lower coal prices favor IGCC with liquid sparing although the impact of coal prices on tariff is marginal for a given financing structure. Figure 9 clearly indicates that at a liquid fuel price of $50 per barrel and coal prices of less than $10 per ton, IGCC with liquid sparing is more competitive than IGCC without liquid sparing and can compete with PC systems, even at current higher IGCC capital costs, when MOU financing is considered.

5.2 Probabilistic Analysis

PERI employed a probabilistic Monte Carlo financial model to analyze the sensitivity of the results of the financial model to changes in the inputs. A Monte Carlo simulation performs a number of iterations of a model (generally hundreds to thousands).During each iteration, the model randomly selects a specific value from each of the input data distributions and calculates the resulting output of the model. The results are then displayed as a distribution of output values or an accumulative probability distribution. They can also be summarized by such statistics as minimum, maximum, mean, standard deviation, and 5% and 95% values. Appendix A presents a description of the probabilistic model and the input functions used for this analysis. The inputs to the financial model that were varied as probabilistic input distributions were: 1) Total EPC Cost; 2) Interest Rate; 3) Coal Feed Rate; 4) Coal Cost ($/ton); and 5) Liquid Price ($/bbl). It should be noted that the coal feed rate and coal heat rate, and therefore the cost per ton of coal, are assumed to be inversely correlated (i.e., at a given heat input, the coal feed rate increases, as the coal heat rate and unit cost per ton decrease).

The uncertainty in EPC cost is assumed to be +/- 25% for PC and IGCC without spare gasifier, and +/- 30% for the IGCC with spare and F-T syngas to liquids system. The uncertainty in the interest rate is assumed to be +/- 2% for the GenCo, LCF and IOU financing structures and +/- 1.5% for the MOU.

The Coal Feed Rate is assumed to vary from +30% to -2% depending on the coal heating value corresponding to $8 per ton for Powder River Basin (PRB) and $35 per ton for Illinois No. 6.

Figure 8 Impact of Capital Cost Reductions on Tariff

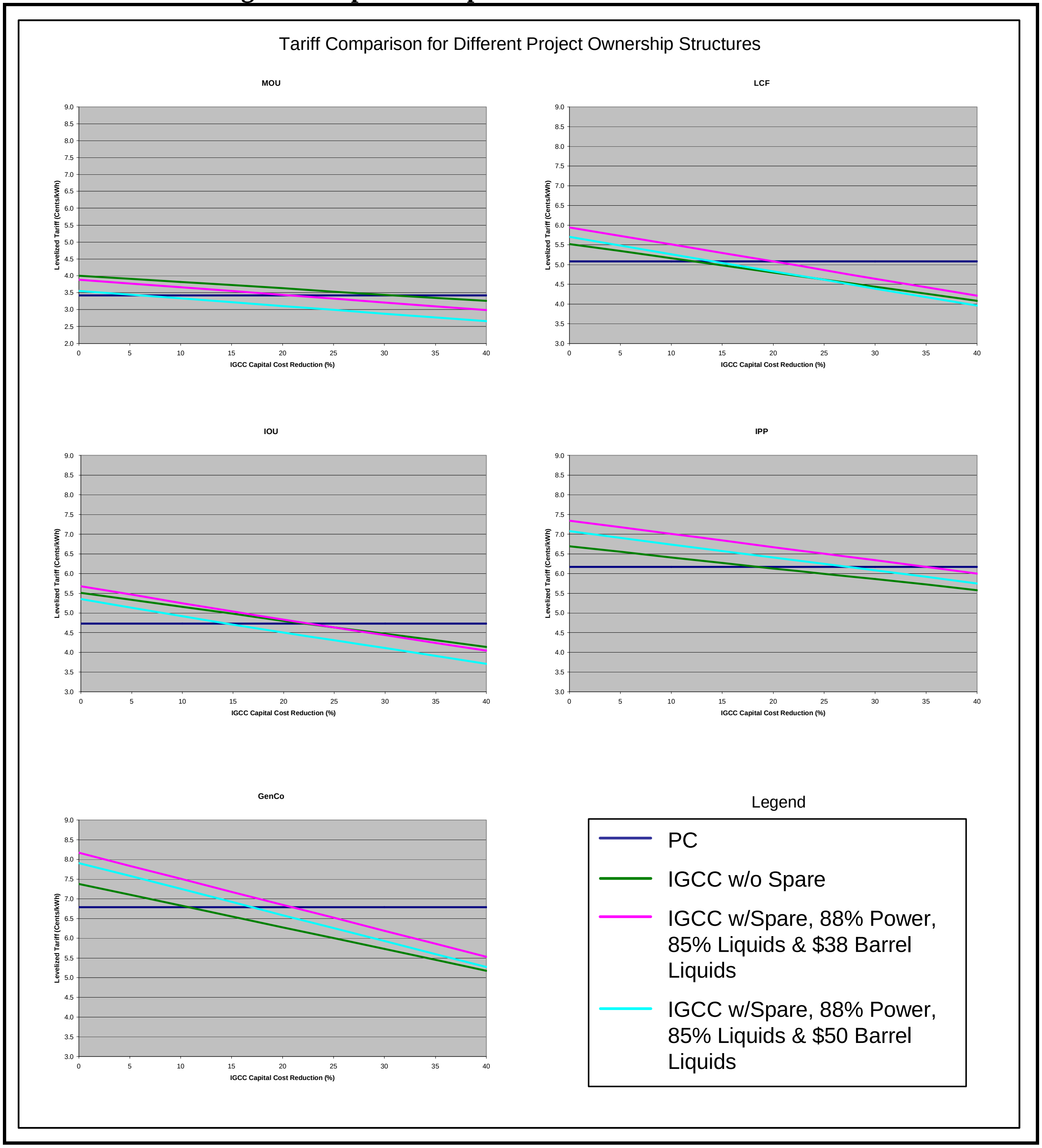
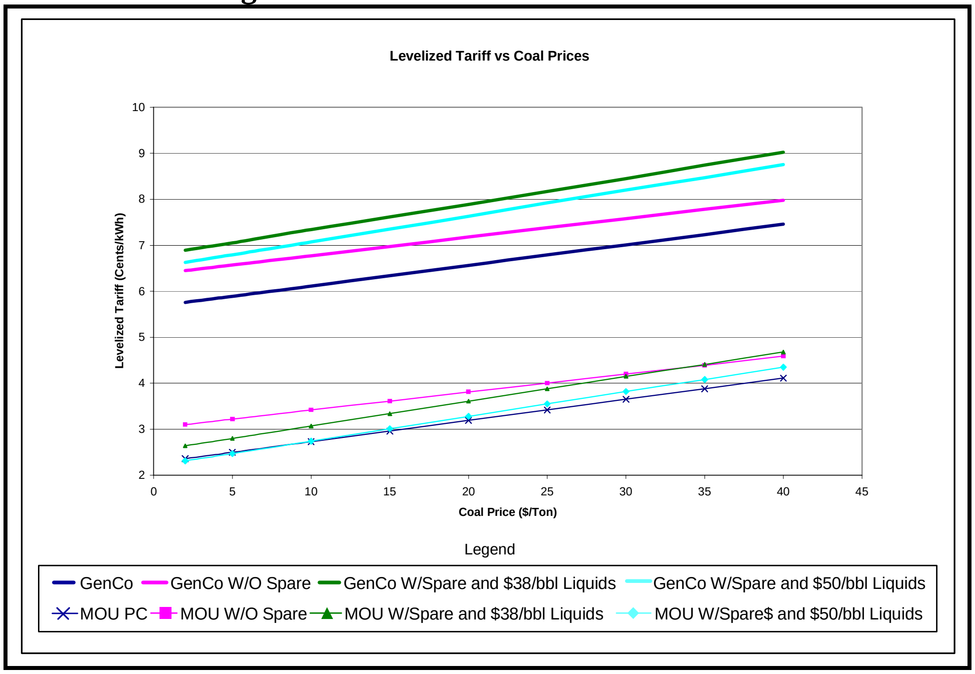


Figure 9 Levelized Tariff vs. Coal Prices



Note: Assumes 88% availability for PC and IGCC with spare gasifier, 78% availability for IGCC without spare and liquid fuel prices of $38/Barrel.

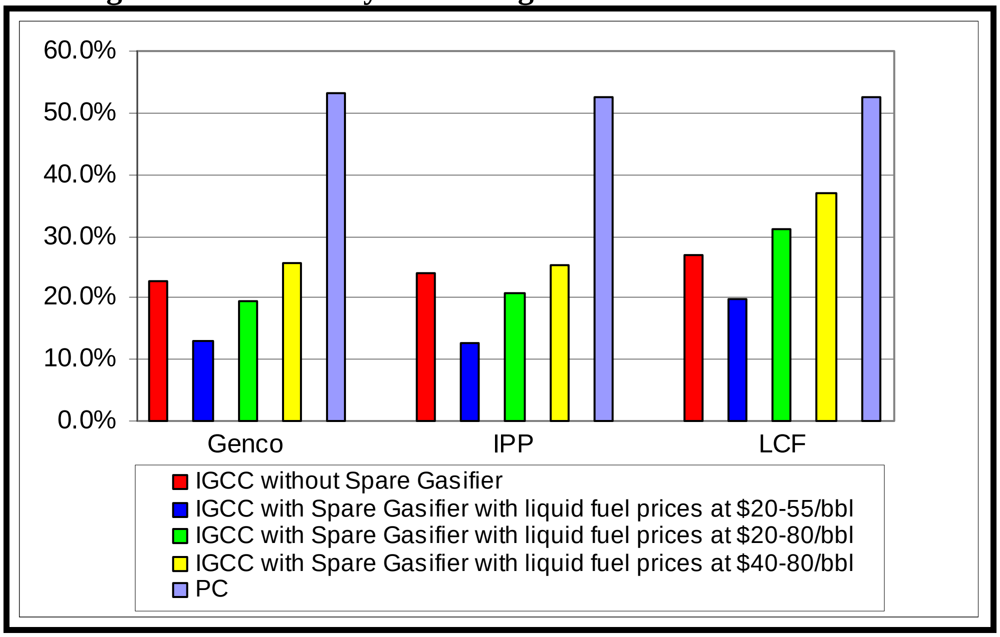
The coal liquid price is assumed to be between $20-$55/bbl, $20-$80/bbl, and $40-$80/bbl. This sensitivity analysis was due in part due to the current price of oil being above $50/bbl, as well as to assess the impacts of extremely low and high oil prices on the tariff of IGCC system with spare gasifier.

The results of the probabilistic analysis are shown in Figures 10 and 12. These probabilities are calculated assuming the same annual tariffs for IGCC, with and without spare, as the annual PC's tariffs shown in Figure 5 for each financing structure. Figure 10 shows the probability of meeting a 12% IRR for various financing structures at various coal-liquid price ranges. The IOU and MOU financing structures are not shown here, as they employ a different financing model.

Figure 10 indicates that while the PC has a better than 50% probability of meeting the desired returns (see Table 5) for each of the financing methods, the IGCC without the spare gasifier has 22% - 28% probability, and the IGCC with spare gasifier has from 12% to 37% probability of meeting the 12% IRR, depending on the financing structure and/or coal-liquid fuel price ranges. Raising the coal liquid price range to $20-$80/bbl, from $20-$50/bbl, increases the probability of meeting the desired return by more than 7 percentage points for the IGCC with the spare gasifier. Liquid prices in the $40-$80/bbl range increase the probability of meeting the 12% IRR for IGGC with spare gasifier to the 25%-37% range. This indicates that the uncertainties associated with IGCC technology with or without spare gasifier are somewhat higher than the PC, and IGCC is less competitive than PC in today's market conditions, even though it has demonstrated superior environmental performance, without governmental support for financial structures shown in Figure 10.

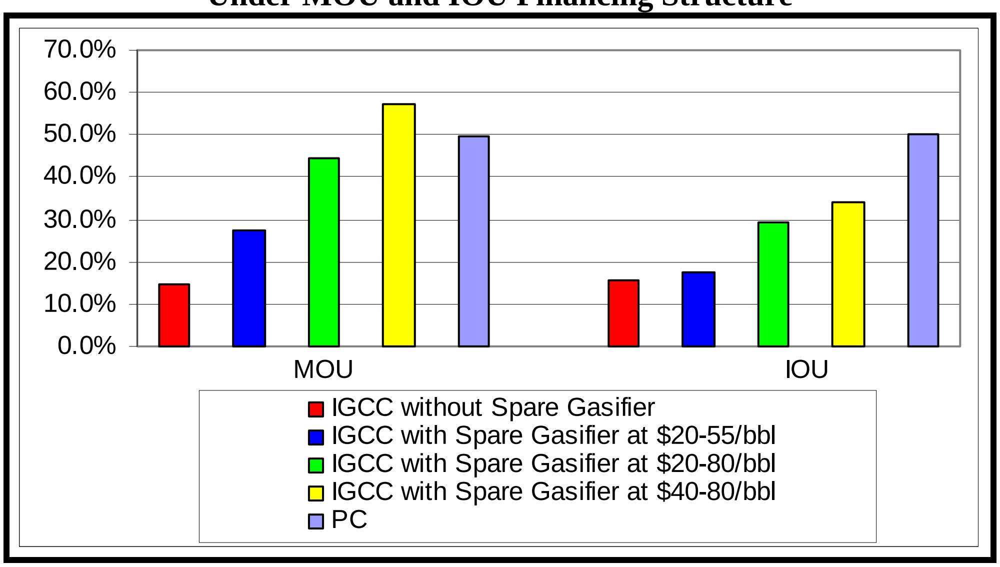
Figure 11 compares the probability of meeting the PC's tariffs for PC and IGCC with and without spare gasifier under the MOU and IOU financing structures at the input ranges specified above. In addition, as noted in Table 5, the IOU financing structure requires

Figure 10 Probability of Meeting a 12% IRR at the PC Tariff



Note: Assumes 88% availability for power generation for PC, IGCC with and without spare, and 85% availability for liquid production for IGCC with spare.

Figure 11 Probability of IGCC Systems Achieving the Same Tariff Rate as PC System Under MOU and IOU Financing Structure



Note: Assumes 88% availability for power generation for PC, IGCC with and without spare, and 85% availability for liquid production for IGCC with spare.

5.5% return on preferred stocks and 9% on common stocks, while MOU financing structure does not require any return on equity. This Figure shows that while IGCC without spare have less than 20% probability meeting PC tariff. IGCC with liquid sparing have much better probability of competing with PC plants. In particular, at liquid fuel price range of \$40-\$80 per barrel, IGCC with liquid sparing has a greater probability of meeting PC tariff than PC, assuming an IOU financing structure. At the \$40-\$80 per bbl liquid fuel price range, the probability of IGCC with liquid sparing to achieve the same tariff as the PC plant is about 58% for an MOU plant.

6. CONCLUSIONS

This analysis indicates that:

A. At coal liquid prices of greater than \$55 per barrel – equivalent to crude oil price of \$44.40 per barrel (assuming a \$10 per barrel premium for coal liquids in 2033 dollars) – IGCC with a spare gasifier for liquid production could be competitive with PC systems depending on the project financial structure. While at \$55 per barrel, IGCC with liquid sparing could be competitive with PC systems, coal liquid prices of about \$100 – equivalent to crude oil price of \$89.40 per barrel is needed to make IGCC with liquid sparing competitive with PC system using a GenCO financing structure. The coal liquid prices needed for other financing structure considered; IOU, LCF, and IPP, falls in \$55 - \$100 per barrel rang.

B. At liquid prices of greater than \$38 per barrel, MOU and IOU financing structures favor IGCC with liquid sparing to IGCC.

C. A reduction of about 20% in the capital costs will make IGCC with liquid sparing competitive with PC systems at liquid prices of about \$38 per barrel under financing structures considered except for IPP financing.

D. At liquid prices of up to \$50 per barrel, GenCo, LCF, and IPP financing structures favor IGCC without liquid sparing to IGCC with liquid sparing. A 10%-18% reduction in the capital cost of IGCC without liquid sparing will make this system competitive with PC. A reduction of 15% - 33% in the capital costs will be needed to make IGCC with sparing liquids competitive with PC systems at liquid prices of about \$50 per barrel under GenCo, LCF, and IPP financing structures.

The production of liquid fuel from coal can enhance our national energy and economic security. However, at low coal liquid fuel (less than \$55 per barrel) a larger coal to liquid plant than the one considered in this study should be considered to potentially take advantage of economy of scale. The size of liquid production plant in this study is relatively small as electric power is considered the primary product and the liquid fuel as a by-product. It may be more economic to produce liquid fuel as the primary product and utilize the resulting waste gas to produce electricity.

MOUs (and COOP's, who have a similar financing structure as MOUs) due to their lower cost of capital, tax exempt status, and the ability to spread the risk of the new plant over the entire system equity can overcome the additional capital cost of IGCC with "liquid sparing" at lower liquid fuel prices than other ownership/financing structures.

This analysis indicates that capital cost reductions of up to 20% will make IGCC systems (with and without liquid sparing) competitive with PC systems under most financing structures. Such a reduction in capital costs seems possible. Forecasts indicates that IGCC learning curve and economy-of-scale will reduce IGCC costs by 25-30% while PC costs can be reduced only by 10-15% as a result of supercritical technology.[21]

Furthermore, repowering of old coal-fired plants could help to reduce capital costs:

A. Repowering provides an estimated 100-150$/kW advantage over green-field IGCC plants.

B. An off-the-books 250MW steam PC plant with 30-33% efficiency can be converted to a 750MW IGCC with 43-45% efficiency, using the existing steam turbine or similar size steam turbine.

Repowering of the existing coal-fired power plants that have reached their useful life provides an opportunity to lower capital costs, especially the project development costs. The existing coal-fired plants already have access to the needed infrastructure for coal transportation and handling, power evacuation and transmission lines, and water supply and transportation. The permitting and environmental approval could be facilitated by the fact that the existing plants are already permitted to use coal and utilizing IGCC technology would provide for a greater environmental performance than a PC boiler. Some of the existing equipment particularly, the steam turbines and their associated auxiliary equipment (feed water pumps, condensers, and generators) could potentially be integrated with the new IGCC system helping to reduce capital costs. Most power plants built during 1960-1980 could potentially be candidates for repowering with IGCC. These plants utilize steam turbines ranging from 250 MWe to 1100 MWe allowing for implementation of IGCC plants in 750 MWe to 33000 MWe range. Repowering of the existing coal power plants will preserve jobs associated with these facilities and would help to maintain the existing coal markets.

[21] Lako, P.; "Coal-fired Power Technologies: Coal-fired Power Options on the Brink of Climate Policies"; October, 2004; ECN-C--04-076

APPENDIX A

Financing Structures

Independent Power Producer (IPP):
An IPP project typically possesses a capital structure equal to 70% debt and 30% equity and its return on investment is set by the market and is not guaranteed. Additionally, debt and equity investment in an IPP is only secured by the assets and cash flow of the single project. A debt service reserve equal to one full debt payment (six months) is maintained throughout the life of the debt to reduce repayment risks. In addition, lenders require that an IPP's ratio of operating income to the annual debt service requirement (the debt service coverage ratio) be no less than 1.5 in the worst year and be 1.8 on the average for the life of the debt. The internal rate of return on the equity for an IPP is expected to compensate for the risks associated with the lack of guaranteed return on investment. Since the returns for the IPP are market-based, the project life for this scheme is equal to 20 years.

Corporate or Balance Sheet Financing:
A *Leveraged Corporate Financing Structure* (LCF) uses a corporate or balance sheet financing scheme. This means that debt and equity investors have access to a pool of corporate assets to secure their investments and it allows the project to utilize an 80% debt and 20% equity corporate structure. The use of balance sheet financing also eliminates the need for a debt service reserve and a minimum debt service coverage ratio since the debt repayment risks have been greatly reduced.

A *Generating Company* (GenCo) structure is similar to the LCF structure except that it uses a capital structure of 65% equity and 35% debt.

Regulated Investor Owned Utility (IOU):
The IOU financing scheme involves a return on investment that is set by the regulatory system, not the market. The revenue stream for this type of project is calculated by summing the operating expenses, taxes, depreciation, and returns to equity and debt investors. The capital structure is about 47% debt, 6% preferred stock, and 47% common stock. The return on equity to investors is set by regulators and is guaranteed. Since this scheme allows investors access to the utilities pool of assets to secure their investment, no debt service reserve or minimum debt service coverage ratios are required. Since the return on investment is guaranteed, the project life is generally assumed to be 30 years, the life of the plant.

Municipal Owned Utility (MOU):
The MOU financing scheme is similar to the IOU scheme with the following exceptions. First, the MOU scheme uses a 100% debt capital structure. Second, the MOU does not pay any taxes.

APPENDIX B

Probabilistic Model

The cases examined for this analysis include PC, IGCC without spare gasifier, and IGCC with a spare gasifier for improving syngas availability for power generation and liquid sparing. The IGCC without a spare gasifier utilizes two gasifiers, each with 78% availability. The IGCC with a spare gasifier technology uses a third gasifier to both produce liquid and increase the availability to 88%, equivalent to the PC technology.

Additionally, a number of financing structures were analyzed, including: GenCo, IPP, LCF, IOU, and MOU.

The inputs to the financial model that were varied as probabilistic input distributions were: 1) Total EPC Cost; 2) Interest Rate; 3) Coal Feed Rate; 4) Coal Cost ($/ton); and 5) Liquid Price ($/bbl).

The coal feed rate and coal heat rate and therefore cost per ton of coal are assumed to be inversely correlated (i.e., at a given heat input, the coal feed rate increases, as the coal heat rate and unit cost per ton decreases). The facility requires a minimum Btu input from the coal, which can be met by lower quantities of high cost coal or higher quantities of low cost coal.

A number of distribution types could be used to characterize the input distributions, including the Normal, Binomial, Chi Square, Triangular, and Uniform (rectangular) distributions. All of the distributions require some upfront (or a priori) knowledge of the characteristics of the distributions. For example, for the Normal distribution, the mean and standard deviation are required. Both the Triangular and Uniform distributions require minimum and maximum values. However, the Triangular distribution also uses a most likely value and produces a distribution in the shape of a triangle, with values closer to the most likely value having a higher probability of being selected. A Uniform distribution produces a rectangular distribution with each point within the range having an equal probability of being selected, and should be used when the range is known, but there is no knowledge of the most likely value.

For this analysis, Triangular distributions were chosen for the Total EPC Cost and Interest Rate, and Uniform distributions were selected for Coal Feed Rate, Coal Cost and Liquid Price. The Uniform distribution was chosen for the Coal Feed Rate, Coal Cost and Liquid Price, as these variables are driven by market forces with no specific value within their ranges expected to have a higher probability of occurrence.

The EPC cost excluding start-up costs is assumed to be: $682,000,000 +/- 25% for the PC; $951,146,000 +/- 25% for the IGCC without spare gasifier and $1,221,368,000 +/- 30% for the IGCC with spare gasifier system including the F-T system.

The Interest Rate is assumed to be: 6% +/- 2% (i.e., 4%-8%) for the GenCo, LCF and IOU financing cases; 8% +/- 2% for the IPP case; and 5% +/- 1.5% for the MOU case.

The Coal Feed Rate is assumed to be: 1,756,134 TPY +30%/-2% for PC; 2,033,414 TPY +30%/-2% for IGCC with spare gasifier; and 1,364,575 TPY +30%/-2% for IGCC without spare gasifier.

The Coal Cost is assumed to be between $8-$35/ton for all cases. Again, the Coal Cost is inversely correlated with the coal heating value and therefore the Coal Feed Rate, such that for each iteration, if a high value is selected for the Coal Feed Rate, a correspondingly low value is selected for Coal Cost.

The Liquid Price (i.e., price of a barrel of oil) is assumed to be between $20-$50/bbl in the base case. Additionally, another set of runs of the model was conducted using a range of $20-80/bbl. This sensitivity analysis was in part due to the current price of oil being above $50/bbl, as well as to assess the impact of very high oil prices on the IGCC with Spare Gasifier case. Table 1 shows all of the input distributions used for each of the different cases.

Table 1 Summary of Inputs to the Probabilistic Monte Carlo Financial Model

Financing Type	Input	Pulverized Coal			IGCC with Spare Gasifier			IGCC without Spare Gasifier		
		Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
GenCo	Total EPC Cost	$511,500,000	$682,000,000	$852,500,000	$854,957,868	$1,221,368,383	$1,587,778,898	$713,359,594	$951,146,125	$1,188,932,656
	Interest Rate (%)	4%	6%	8%	4%	6%	8%	4%	6%	8%
	Coal Consumption Rate (TPY)	1,721,011		2,282,974	1,992,746		2,643,438	1,337,284		1,773,948
	Coal Cost ($/ton)	8		35	8		35	8		35
	Liquid Price ($/bbl)	20		80	20		80	20		80
IPP	Total EPC Cost	$511,500,000	$682,000,000	$852,500,000	$854,957,868	$1,221,368,383	$1,587,778,898	$713,359,594	$951,146,125	$1,188,932,656
	Interest Rate (%)	6%	8%	10%	6%	8%	10%	6%	8%	10%
	Coal Consumption Rate (TPY)	1,721,011		2,282,974	1,992,746		2,643,438	1,337,284		1,773,948
	Coal Cost ($/ton)	8		35	8		35	8		35
	Liquid Price ($/bbl)	20		80	20		80	20		80
LCF	Total EPC Cost	$511,500,000	$682,000,000	$852,500,000	$854,957,868	$1,221,368,383	$1,587,778,898	$713,359,594	$951,146,125	$1,188,932,656
	Interest Rate (%)	4%	6%	8%	4%	6%	8%	4%	6%	8%
	Coal Consumption Rate (TPY)	1,721,011		2,282,974	1,992,746		2,643,438	1,337,284		1,773,948
	Coal Cost ($/ton)	8		35	8		35	8		35
	Liquid Price ($/bbl)	20		80	20		80	20		80
IOU	Total EPC Cost	$511,500,000	$682,000,000	$852,500,000	$854,957,868	$1,221,368,383	$1,587,778,898	$713,359,594	$951,146,125	$1,188,932,656
	Interest Rate (%)	4%	6%	8%	4%	6%	8%	4%	6%	8%
	Coal Consumption Rate (TPY)	1,721,011		2,282,974	1,992,746		2,643,438	1,337,284		1,773,948
	Coal Cost ($/ton)	8		35	8		35	8		35
	Liquid Price ($/bbl)	20		80	20		80	20		80
MOU	Total EPC Cost	$511,500,000	$682,000,000	$852,500,000	$854,957,868	$1,221,368,383	$1,587,778,898	$713,359,594	$951,146,125	$1,188,932,656
	Interest Rate (%)	3.5%	5%	6.5%	3.5%	5%	6.5%	3.5%	5%	6.5%
	Coal Consumption Rate (TPY)	1,721,011		2,282,974	1,992,746		2,643,438	1,337,284		1,773,948
	Coal Cost ($/ton)	8		35	8		35	8		35
	Liquid Price ($/bbl)	20		80	20		80	20		80

Table 2. Summary of Outputs to the Probabilistic Monte Carlo Financial Model.

Financing Type	Input	Pulverized Coal			IGCC with Spare Gasifier			IGCC without Spare Gasifier		
		Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum
GenCo	Internal Rate of Return (%)	7.00%	12.26%	17.79%	0.32%	8.08%	16.35%	2.31%	8.22%	15.51%
	Total Project Cost	$676,289,280	$898,329,281	$1,121,172,224	$1,129,109,120	$1,591,535,552	$2,058,623,104	$937,458,176	$1,240,405,429	$1,532,046,976
IPP	Internal Rate of Return (%)	2.32%	12.37%	23.65%	-2.92%	6.03%	21.05%	-5.12%	5.28%	18.31%
	Total Project Cost	$685,713,728	$932,660,265	$1,151,081,856	$1,159,186,560	$1,650,403,893	$2,162,960,384	$983,294,144	$1,286,476,099	$1,618,446,720
LCF	Internal Rate of Return (%)	-2.48%	12.34%	25.19%	-1.89%	6.84%	26.20%	-3.01%	5.42%	22.03%
	Total Project Cost	$697,596,224	$917,248,660	$1,133,827,200	$1,142,473,600	$1,624,952,048	$2,109,083,776	$970,600,064	$1,266,646,377	$1,608,434,560
MOU	Average Tariff ($/kWh)	2.17	3.37	4.54	2.04	3.85	5.71	2.86	4.22	5.55
	Total Project Cost	$690,791,872	$913,032,707	$1,138,745,344	$1,144,394,240	$1,617,638,888	$2,082,912,000	$962,334,592	$1,260,745,173	$1,569,434,112

Integrated Gasification Combined Cycle (IGCC) is an advanced, efficient, and environmentally friendly method of generating electricity compared to the traditional method of burning pulverized coal in a boiler in order to produce steam to drive a steam turbine/generator. IGCC relies on first gasifying the coal to produce a synthetic gas (syngas), combusting the syngas in a gas turbine to generate electricity, recovering the heat from the combustion turbine exhaust, gasifier vessel, and syngas cooling system to generate steam to drive a turbine for additional power generation. In coal gasification, coal is reacted with steam in a gasifier under controlled pressure, temperature, and amounts of oxygen or air environment. In this environment thermo-chemical reactions cause coal's molecular structure to break down and undergo a series of chemical reactions with steam and oxygen to produce a gaseous mixture commonly referred to as synthesis gas, syngas, coal gas, or producer gas. It is composed primarily of carbon monoxide and hydrogen.