HARVARD UNIVERSITY

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Deploying IGCC In this Decade With 3Party Covenant Financing

Volume I

May 2005 Revision

William G. Rosenberg, Dwight C. Alpern, Michael R. Walker

Energy Technology Innovation Project
a joint project of the
Science, Technology and Public Policy Program
and the
Environment and Natural Resources Program
Belfer Center for Science and International Affairs

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FOREWORD

These two volumes emanate from fourteen months of research, discussion and countless drafts. The three authors, William Rosenberg, Dwight Alpern, and Michael Walker, conducted meetings with key players, including officials from both the federal and state government, representatives of the power, engineering, coal and chemical industries, environmental groups and academic experts. We are especially grateful for the cooperation of the Carbon Mitigation Initiative at Princeton University and two of its leaders, Robert Socolow and Robert Williams, and for the continuing advice from the MIT Laboratory for Energy and the Environment.

Both of these volumes have been extensively peer reviewed by a team of experts, including faculty at Harvard, Yale, and Princeton. The authors have consulted with officials from the Electric Power Research Institute (EPRI), Center for Clean Air Policy (CCAP), and the National Association of Regulatory Utility Commissioners (NARUC). The authors also benefited from a workshop held at the John F. Kennedy School in February, 2004. Over eighty experts from across the country participated in a discussion on opportunities to overcome the financial and political challenges confronting the deployment and commercialization of Integrated Gasification Combined Cycle technologies (IGCC), (see the ENRP rapporteur's report: "Workshop on Integrated Gasification Combined Cycle: Financing and Deploying IGCC Technologies in this Decade," #2004-06).

These reports are part of a three-year program in the Kennedy School's Energy Technology Innovation Project (ETIP), a joint effort of the Environment and Natural Resources Program (ENRP) and the Science, Technology and Public Policy Program (STPP). ETIP has fostered extensive work on the obstacles and opportunities for development and utilization of IGCC technologies in China and India, as well as in the United States.

These efforts are stimulated by three policy imperatives: the need to increase the use of indigenous coal supplies and to meet a growing demand for electricity; the need to clean up our air, and reduce the threat of global climate change; and the need to address the nation's energy security. These reports provide a blueprint of how the United States might take the initial steps to commercially deploy IGCC technology to significantly improve our air, economy, and national interest.

We are very grateful for the support of the National Commission on Energy Policy, the Department of Energy, the Environmental Protection Agency, the Hewlett Foundation, the Packard Foundation, the Roy Family Fund, and the hundreds of experts who have generously given the authors the benefit of their advice and counsel.

John Holdren and Henry Lee
Co-chairs, Energy Technology and Innovation Project

REPORT ORGANIZATION

The paper is divided into two volumes. Volume I describes IGCC technology, why it is an important advanced clean coal technology for generating electricity, the hurdles to near-term deployment, the 3Party Covenant financing and regulatory program to stimulate near-term IGCC deployment, and how the 3Party Covenant improves the economics of IGCC technology to make it competitive. Appendix A of Volume I outlines the components of federal legislation that are needed to implement the 3Party Covenant.

Volume II provides a detailed legal analysis of the federal and state authorities and regulatory mechanisms for implementing the 3Party Covenant, including a review of traditional electric utility regulatory systems, the current regulatory systems in 5 specific states, and a model regulatory mechanism for review and approval of IGCC project costs under the 3Party Covenant.

May 2005 Revision

This paper is a revised version of the authors' July 2004 working paper. The update adjusts the equity return used in calculating levelized carrying charges and energy costs in the report by reducing the modeled return from 18.6 percent to 11.5 percent. This change eliminates an unintentional double counting of tax implications that was identified in calculations presented in the July 2004 report. The update also includes some other minor changes, which reflect or result from the adjustment of the modeled equity return.

TABLE OF CONTENTS

VOLUME I

EXECUTIVE SUMMARY

This paper describes a 3Party Covenant financing and regulatory proposal (“3Party Covenant”) aimed at reducing financing costs and providing a technology risk tolerant investment structure to stimulate initial deployment of 3,500 MW (about six 550 MW plants) of Integrated Gasification Combined Cycle (IGCC) coal generation power plants in this decade. The 3Party Covenant is an arrangement between the federal government, state utility commission (state PUC), and equity investor[1] that serves to lower IGCC cost of capital[2] by reducing the cost of debt, raising the debt/equity ratio, minimizing construction financing costs, and allocating financial risk. The 3Party Covenant reduces the cost of capital component of energy costs from new IGCC facilities by approximately 30 percent and the overall cost of energy about 17 percent, making power produced from IGCC technology cost competitive with pulverized coal (PC)[3] and natural gas combined cycle (NGCC) generation.

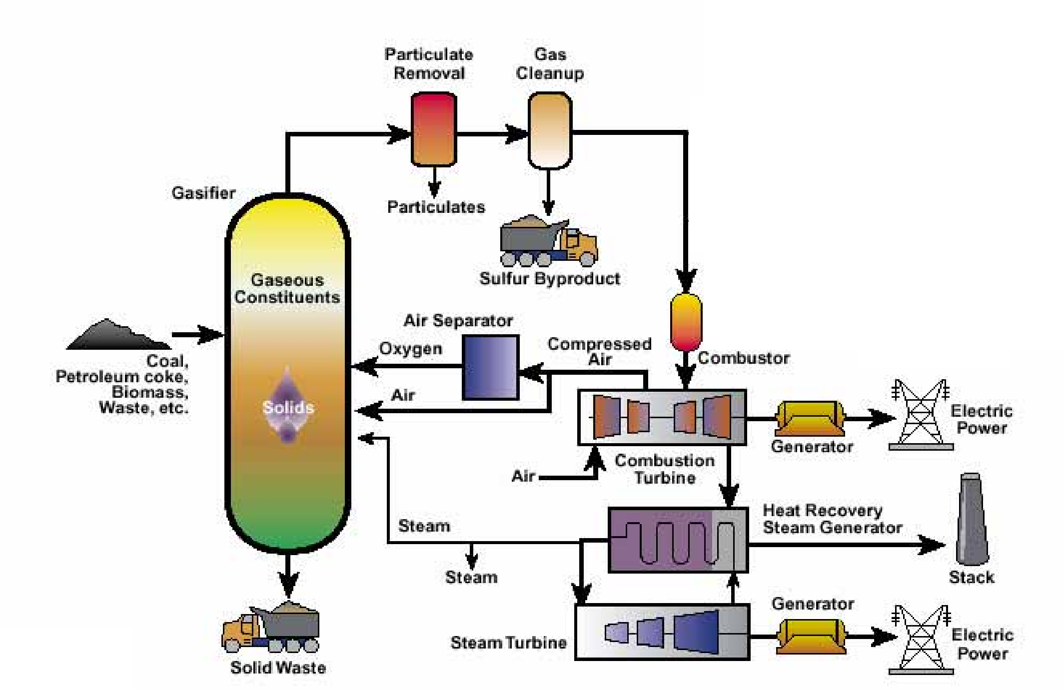
ES-1. Integrated Gasification Combined Cycle Generation

IGCC is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block. As illustrated in Figure 1-1, the gasification system converts coal (or other solid or liquid feedstocks such as petroleum coke or heavy oils) into a gaseous “syngas,” which is made of predominately hydrogen (H_2) and carbon monoxide (CO). The combustible syngas is used to fuel a combustion turbine to generate electricity, and the exhaust heat from the combustion turbine is used to produce steam for a second generation cycle and provide steam to the gasification process.[4]

Despite the worldwide commercial use and acceptance of gasification processes and combined cycle power systems, IGCC is not perceived in the U.S. to have sufficient operating experience to be ready to use in commercial applications.[5] Each major component of IGCC has been broadly utilized in industrial and power generation applications, but the integration of a coal gasification island with a combined cycle power block to produce commercial electricity as a primary output is relatively new and has

[1] The “equity investor” is likely to be either an electric utility company (or a municipal utility or rural electric cooperative), or independent power company with a purchase contract with a utility (or a contract with comparable credit rating), that provides the equity for a project.
[2] As used in this paper, the term “cost of capital” means debt interest and authorized return on equity.
[3] As used in this paper, the term “PC” or “super-critical PC”means a power generation process that uses a super-critical, pulverized coal-fired boiler incorporating the latest emissions control technologies, including fabric filter baghouses or electrostatic precipitators for particulate control, flue gas desulfurization (FGD) for sulfur dioxide control, and selective catalytic reduction (SCR) to control oxides of nitrogen.
[4] With minor adjustments, combustion turbines designed to operate on natural gas can use syngas. The primary difference that affects the turbine is that syngas has a lower heating value than natural gas, which makes for a larger mass flow of fuel through the turbine that requires different piping and increases turbine output. Natural gas has a heating value of 1,026 btu/ft^3, while syngas has a heating value of 200-300 btu/ft^3.
[5] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.

Figure ES-1. IGCC Power Plant



Source: NETL

been demonstrated at only a handful of facilities around the world. The Overnight Capital Cost[6] of the engineering, procurement, and construction (EPC) contract for IGCC is currently estimated to be about 20 percent higher than PC systems[7] and commercial reliability has not yet been established. As a result, investments to build IGCC facilities to generate power have not materialized despite significant public and private sector interest in the technology.

ES-2. Why IGCC

IGCC was selected as the focus of this paper because it is a commercially ready, advanced technology for generating electricity with coal that is widely supported and can substantially reduce air emissions, water consumption, and solid waste production from

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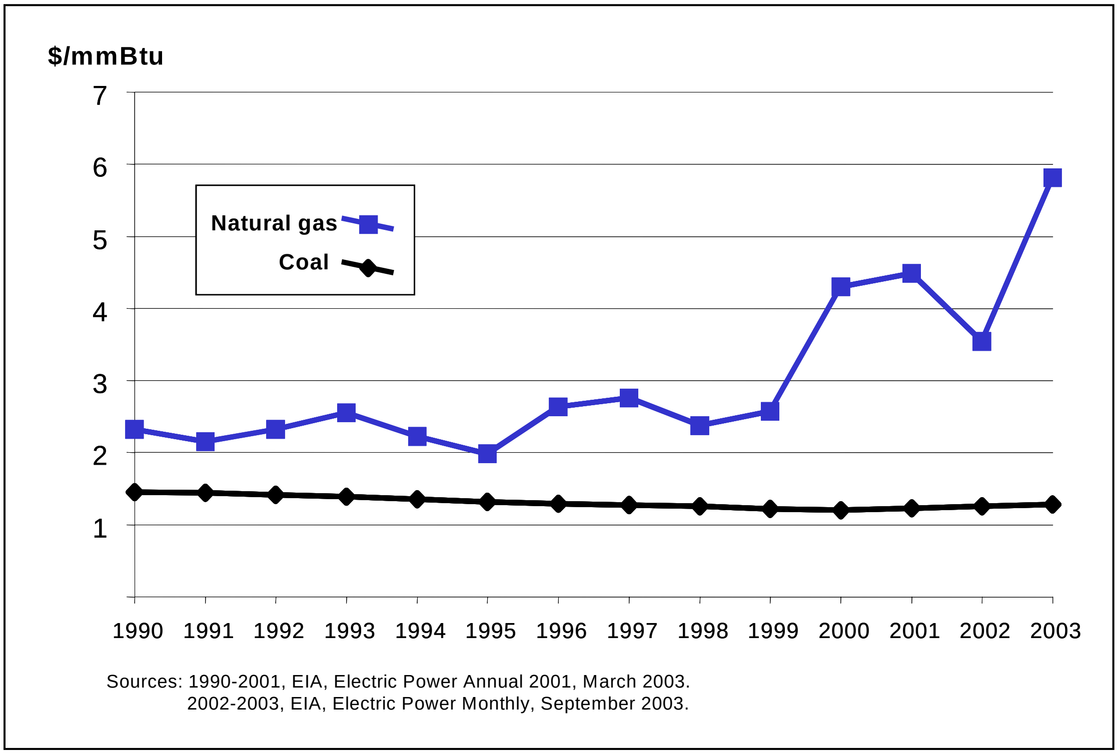
[6] As used in this paper, the term "Overnight Capital Cost" means the bare cost of designing and building a power plant, including engineering, procurement, construction and contingencies, but not considering cost of capital.

[7] However, the current market for combustion turbines, a key component of IGCC power plants, is very soft, which may allow for more cost-competitive IGCC than most studies indicate. Completed natural gas combined cycle units and unused turbines that have never been installed are available for purchase at a very substantial discount. According to NETL, there are as many as 50 turbines currently in warehouses that could potentially be used for new power plants.

Figure ES-2. Average Delivered Fuel Prices to Electric Generators



coal power plants.[8] The Department of Energy (DOE) has invested billions of dollars over the last 20 years to support the technology, and there are fully demonstrated and commercially operating plants in the U.S., Europe, and Japan. IGCC also offers the potential of a technical pathway for cost effective separation and capture of carbon dioxide (CO_2) emissions and for co-production of hydrogen. These environmental attributes make it an important technology for enabling the substantial energy, economic, and national security benefits of coal use for electricity generation to be achieved with minimal environmental impact.

Coal is a vital U.S. energy resource that currently fuels over 50% of U.S. electricity generation. The U.S. has 25 percent of the world's proven coal reserves, more than any other country in the world. This supply enables the U.S. to be a net coal exporter.[9] In contrast, the U.S. has less than 3 percent of world oil and natural gas reserves,[10] imports over 50% of its oil supply (compared to 28 percent just prior to the first Arab Oil

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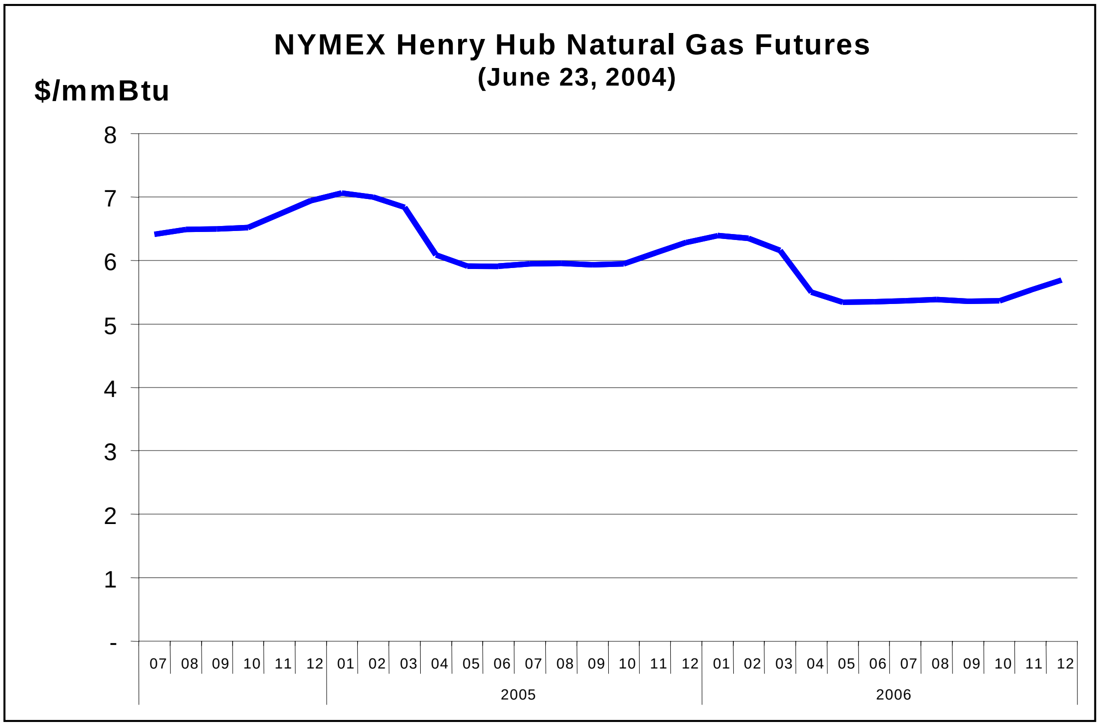
[8] The type of financing program described in this paper could also be effective for other technologies that have similar environmental characteristics.

[9] Estimated recoverable coal reserves in the U.S. are 275 billion tons, which is approximately 25 percent of world reserves and more than a 250-year supply at current consumption (See National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003).

[10] U.S. oil and natural gas reserves are estimated to be less than 2 percent and 3 percent of world totals, respectively. (See EIA, "International Energy Annual 2001," Table 8.1).

Figure ES-3. Henry Hub Natural Gas Futures



Embargo), and is expanding natural gas imports from mid-eastern and other countries through development of liquefied natural gas (LNG) production and transport facilities.[11]

Real coal prices have declined 63 percent since 1980 and real retail electricity prices, which are directly affected by coal prices, have declined 21 percent over the same period.[12] The average price of coal delivered to electric generators in December, 2003 was $1.25/mmBtu, compared to $3.90/mmBtu for petroleum and $5.24/mmBtu for delivered natural gas.[13] As illustrated in Figure ES-2, electric generator natural gas prices have become increasingly volatile in recent years while coal prices have remained relatively stable and slowly declined for the past decade. Coal price stability translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel. Domestic coal, which is geographically dispersed across the country, transported by rail and barge, and can be stockpiled for 30-90 days at generating facilities, is a secure and reliable energy source.

Coal electricity generation can also help relieve pressure on natural gas availability and prices that are adversely affecting other sectors of the economy. Natural gas prices in 2003 were two to three times above historic averages and, as illustrated in Figure ES-3, natural gas futures suggest prices will remain high for at least the next several years.

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[11] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.
[12] See EIA, "Annual Energy Review 2002," October 2003, Tables 7.8 and 8.6.
[13] See EIA, "Electric Power Monthly," April 2004, Table ES1.A.

These high natural gas prices caused widespread, adverse impacts on the U.S. economy and economic competitiveness, including significant job losses in manufacturing and chemicals industries.[14] One factor supporting high natural gas prices and price forecasts is the increased demand resulting from construction of new natural gas-fired electric generation. According to EIA, natural gas consumption by electric generators increased 40% between 1997 and 2002 and will increase another 51% by 2025.[15] Coal generation in general, and IGCC in particular (which can be used to refuel natural gas plants to coal), can help reduce pressure on natural gas prices.[16]

For the nation to enjoy the energy and economic advantages of coal generation without risking significant adverse environmental and health impacts, advanced coal generation technologies need to be deployed that address air pollution, climate change, and other environmental concerns associated with traditional coal combustion technologies. IGCC offers the potential for coal generation with significantly improved environmental performance, particularly reduced air emissions, through gasification and removal of impurities prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases.[17] Because the syngas produced in the gasification process has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions.

For example, there is no single proven technology available today that can uniformly control mercury emissions from PC power plants in a cost-effective manner, while consistently achieving mercury removal levels of 90 percent.[18] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (95-99 percent) mercury

[14] The economic consequences of high prices are described in the House Speaker's Task Force for Affordable Natural Gas report, which states: "Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries." House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (Sept. 30, 2003).

[15] See http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm; See also EIA, Annual Energy Outlook 2004, Table A-13.

[16] In contrast to natural gas, increased use of coal for electricity generation, has very little impact on other sectors of the economy because coal use in the U.S. is essentially dedicated to electricity generation, with 90 percent of coal consumption in the U.S. attributable to electric generators. See EIA, "Annual Energy Outlook 2003 (AEO 2003)," Table A16, Jan. 2003.

[17] Typical combustion and post-combustion controls required of new PC power plants include Flue Gas Desulfurization (FGD, or "scrubbers") for SO_2 control, low NOx burners and Selective Catalytic Reduction (SCR) for NOx control, and Electro-Static Precipitators (ESP) or fabric filter baghouses for particulate control. These technologies add to the capital cost, size and complexity of new PC power plants and decrease plant efficiency because of their energy consumption.

[18] NETL, "The Cost of Mercury Removal in an IGCC Plant," p. 1, Sept. 2002.

control with established technology.[19] In addition, IGCC technology offers the potential for separating and capturing CO_2 emissions (and producing pure hydrogen) by adding water-gas shift reactors to the syngas treatment system and physical absorption processes to remove CO_2. These processes are commercially proven in industrial processes, and several studies have shown this to be a more cost-effective approach to CO_2 capture[20] with proven technology than capturing CO_2 from the flue gas of a PC boiler.[21]

U.S. leadership in the deployment of IGCC technology also could be very beneficial in steering coal-intensive developing countries, such as China and India, towards more environmentally and climate friendly coal use. Near-term deployment of technology capable of addressing CO_2 emissions is critical to avoid locking in traditional steam coal technology for the 30 to 50 year life of new coal plants for the 1,400 giga-watts of new capacity projected to come on line by 2030.[22]

ES-3. IGCC Deployment

For IGCC to be perceived as mature, reliable, and economic, more commercial experience needs to be gained through deployment. However, in order to attract the investment needed for deployment, the technology needs to be perceived as commercially mature, reliable, and economic. Helping resolve this dilemma through commercial deployment of an initial fleet of IGCC power plants is the principal objective of the 3Party Covenant financing and regulatory program.

High natural gas prices, broad political interest, and a growing need for new base load electricity supplies are creating a window of opportunity for IGCC. Many diverse interests, including coal producers and utilities, state and federal government officials, industrial and residential natural gas consumers, and environmental organizations have expressed support for the technology.

At the same time, there has been a resurgence of proposals for PC coal power plant development, with over 94 new coal plants identified as under development in the U.S. as of February, 2004. As illustrated in Figure ES-4, during the period 2005 to 2015, EIA projects the addition of 57 giga-watts of new coal, nuclear, and combined cycle gas generating capacity to serve electricity demand, which is equivalent to about 100 new

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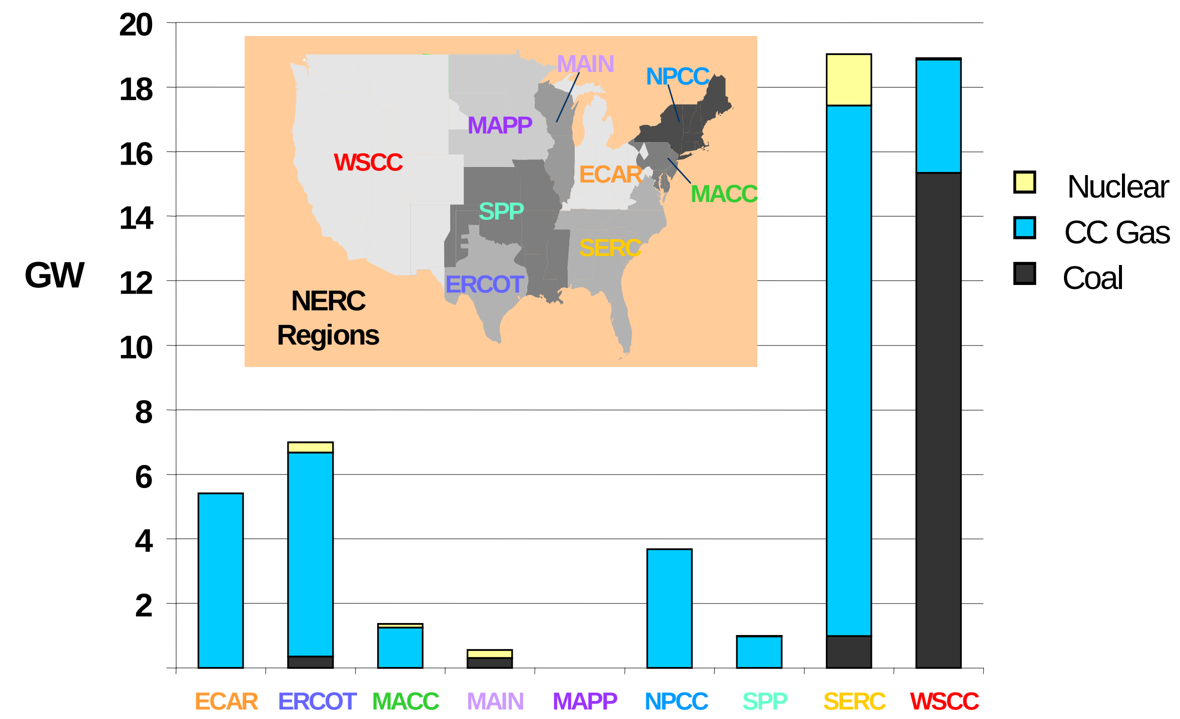
[19] Id.

[20] Although capturing CO_2 is only the first step in controlling it (because it must be sequestered if emissions are to be reduced), most experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal power plant would be in a position to sequester its CO_2. Sequestration is not specifically addressed in this paper because it is viewed by the authors as beyond the scope of commercialization of a small initial fleet of IGCC plants, which is the objective of the 3Party Covenant proposal.

[21] See Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000; See also DOE—EPRI Report 1000316, Dec. 2000.

[22] See Fridtjof Unander and Carmen Difiglio, International Energy Agency, Energy Technology Policy Division, "Energy and Technology Perspectives: Insights from IEA modeling," presented at the National Energy Modeling System/Annual Energy Outlook 2003 Conference, Mar. 18, 2003.

Figure ES-4. EIA 2005-2015 Coal, Nuclear, and NGCC Capacity Additions



Source: EIA, Annual Energy Outlook 2004, Supplemental Regional Data, Table 75.

550 MW power plants (average of 10 per year). If current fuel price trends continue, a substantial portion of the new capacity is likely to be coal fueled utilizing PC technology. A window of opportunity exists for IGCC technology to account for an important share of this new capacity and prove its commercial viability in the near term.

In addition, market availability of underutilized NGCC generation assets at discount prices presents an opportunity for cost-effective coal gasification refueling. The combined cycle power block associated with a NGCC power plant is essentially the same as the combined cycle power block needed for an IGCC facility. To convert an existing natural gas turbine to use synthesis gas from a coal gasifier is a minor adjustment estimated to cost only $5 million for a typical 350 MW plant, or roughly $15/kW.[23] This cost is more than made up for by the savings associated with using a financially distressed asset to provide the combined cycle power block for the IGCC plant. Furthermore, for an owner of a distressed NGCC facility, refueling to IGCC means taking a depressed asset facing large write-offs that is operating at only a fraction of its capacity and repositioning it to operate as a base load coal facility that operates at a high (80-90%) capacity factor with close to par valuation. With 3Party Covenant financing,

[23] NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.

the cost of energy from the resulting plant is as much as 19 percent below the cost of energy from a new PC plant (see Figure ES-10 below).

Despite these opportunities, investments to design and build commercial IGCC power plants in the U.S. have not yet materialized due to cost and risk concerns. A 2004 survey by DOE indicates that the three leading risk factors perceived by industry to be associated with IGCC investments are high capital costs, excessive down time, and difficulty with financing.[24] The financing hurdle is made all the more difficult by the fact the electric utility industry today is weaker financially than it has been in the past. A November 2003 analyst report by Standards and Poors indicated that:

> "the average credit rating for the electric utility sector is now firmly in the 'BBB' category, down from the 'A' category three years ago. Furthermore, prospects for credit quality remain challenging, as indicated by rating outlooks, 40 percent of which are negative."[25]

Lower credit ratings make if more difficult and costly for power companies to raise money for large, capital-intensive coal projects (whether PC or IGCC) costing close to a billion dollars. Add the uncertainty of a relatively new generating technology such as IGCC, and financing becomes a serious constraint to deployment.

ES-4. 3Party Covenant Financing and Regulatory Program

The 3Party Covenant is a financing and regulatory program for providing developers of IGCC power plants with ready access to capital at lower cost in an environment that tolerates technology risk. By so doing, the 3Party Covenant addresses the fundamental economic and financial challenges inhibiting IGCC deployment. The program is designed to facilitate development of an initial fleet of commercial IGCC plants this decade to establish the commercial viability of the technology and reduce costs.[26]

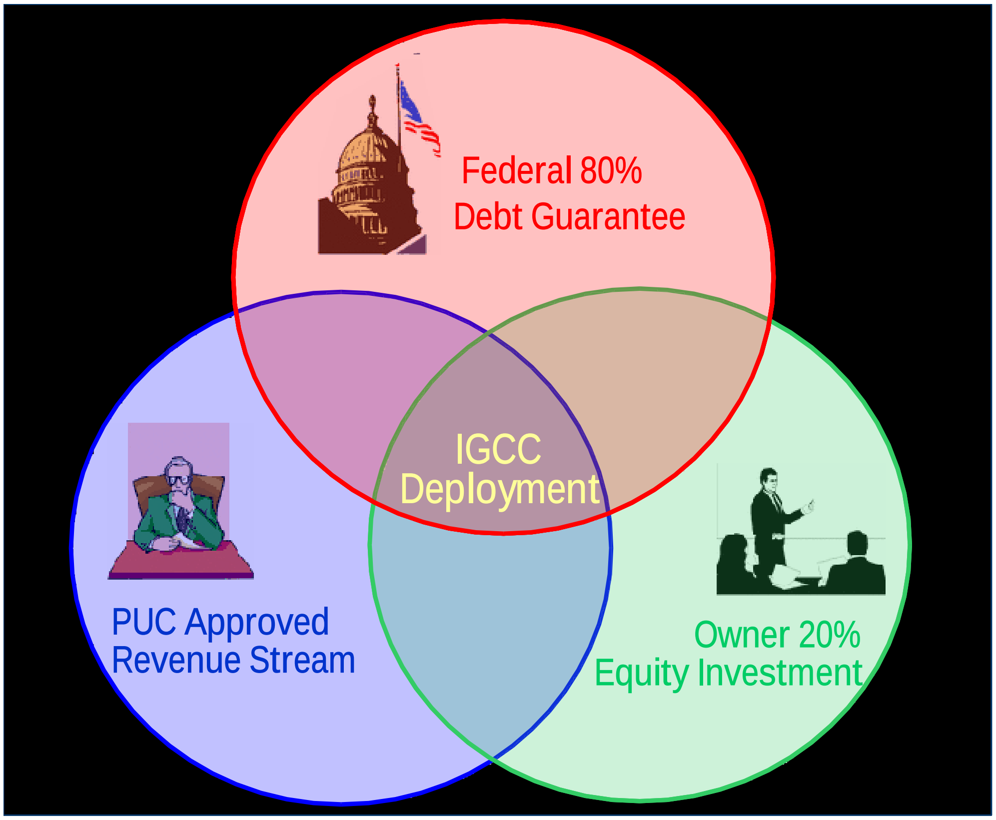
As illustrated in Figure ES-5, the 3Party Covenant is a financial and regulatory arrangement among a federal agency, a state PUC (or other utility rate setting body), and an equity investor. Under the 3Party Covenant, the federal government provides AAA credit, the state PUC provides an assured revenue stream to cover cost of capital and protect the federal credit, and the owner provides equity and know-how to build the IGCC project with appropriate guarantees from an EPC firm (which in turn has underlying warranties from equipment vendors). In return, the federal government

[24] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.

[25] Ronald M Baron, *"U.S. Power and Energy Credit Outlook Not Promising; Few Bright Spots,"* Standard & Poors, Nov. 11, 2003.

[26] Public sector support for commercialization of innovative new technologies was identified as an important recommendation of the PCAST Energy R&D Panel in 1997, which recommended among other things "targeted efforts to improve the prospects of commercialization of the fruits of publicly funded energy R&D in specific areas." (See PCAST Energy R&D Panel 1997, *Federal Energy Research & Development for the Challenges of the 21st Century*, Report of the Energy R&D Panel, The President's Committee of Advisors on Science and Technology, Nov., 1997).

Figure ES-5. 3Party Covenant Illustration



stimulates IGCC deployment to support energy, national security, and environmental policy objectives at low federal cost; the state receives competitively priced power, economic development (investment and jobs), and environmental improvement; and the equity investor receives access to non-recourse, low-cost debt, assured equity returns, and an economic base-load power plant.

The three key elements are as follows:

> *Federal Loan Guarantee:* The program for implementing the 3Party Covenant is established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee provide for an 80/20 debt to equity financing structure and require that a proposed project obtain from a state PUC an assured revenue stream to cover return of capital, cost of capital, and operating costs. The terms also require the project to have appropriate construction guarantees from the EPC firm hired to design and build the plant, and to meet stringent environmental performance specifications. The terms would also enable the project to have available an additional draw on the federally guaranteed debt ("Line of Credit") of up to 15 percent of project Overnight Capital Costs (to be matched with a 20 percent equity contribution when drawn).

State PUC Approval Process: States interested in participating in the program voluntarily opt-in by adopting utility regulatory provisions for state PUC review and approval of IGCC project costs,[27] which in some states will require legislative action to create appropriate enabling authority.

Specifically, a state PUC (or potentially another ratemaking body in the case of a municipal utility or rural electric cooperative), acting under state enabling authority, assures dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation and maintenance, fuel costs, and taxes).[28] The state PUC provides this revenue certainty through utility rates in states with traditional regulation of retail electricity sales, or through non-bypassable wires charges in states with competitive retail electricity sales, by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery of approved costs, including cost of capital. The certification by the state PUC occurs upfront when the decision to proceed with the project is being made, and the prudence review by the state PUC and cost recovery occur on an ongoing basis starting during construction, which reduces the construction risks borne by the developer, avoids accrual of construction financing expenses, and protects ratepayers.

Equity Investor: The equity investor under the 3Party Covenant is likely to be either an electric utility (or a municipal utility or rural electric cooperative) or an independent power producer that secures a long-term power contract with a utility (or a contract with a comparable credit rating). The investor contributes equity for 20 percent of the Total Plant Investment and negotiates performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return is determined and approved by the state PUC before construction begins.

The 3Party Covenant is distinguished from other federal financing programs because a principal party is a state PUC (or potentially another ratemaking body for a municipal utility or rural electric cooperative), which effectively assures the revenue stream needed to service the federally guaranteed debt. The regulatory body, operating under state enabling law, reviews and approves the IGCC plant proposal upfront, determines the need for power, establishes the mechanism for allocation of project risks and recovery of approved costs, conducts ongoing prudence review during construction and operation, and determines the amount and timing of project revenues. The 3Party Covenant requires states that want to participate to establish a review and approval process that provides for

[27] As used in this report, the term "project costs" refers to all costs associated with building and operating a power plant, including all development costs, capital and financing costs, and operating costs.
[28] Depending on the ownership structure and sales profile (i.e., retail sales versus sales for resale) of the IGCC project, the Federal Energy Regulatory Commission (FERC) may take on some of the role otherwise assigned to the state PUC.

cost recovery assurances to protect the federal loan guarantee before the guarantee becomes effective.

The 3Party Covenant is designed to benefit and protect ratepayers by enabling them to receive lower cost (because of access to lower cost financing)[29] and less polluting power without being required to take excessive risk. Ratepayer risks are mitigated under the 3Party Covenant by EPC contractor construction guarantees (and underlying equipment vendor warranties) required to cover construction risks, a 15 percent Line of Credit (percentages based on Overnight Capital Costs) to cover construction and operating risks that are the responsibility of the owner, and the state PUC process evaluating the prudence of the IGCC investment decision and operation.[30] It is ultimately up to the state PUC, through a transparent public process, to determine whether the public benefits of building a new IGCC power plant under the 3Party Covenant outweigh the risks to ratepayers.[31] The decision will only be made where the PUC determines that there is a need for new base load power and will entail weighing the future benefits, risks, and cost of 3Party Covenant financed IGCC against the benefits, risks, and costs of conventionally financed alternative base load generation (PC).[32]

Once the state PUC assures revenues to service the federally guaranteed loan, the amount of the loan that must be scored as a federal budget expense is likely to be significantly lower, because risk of default is significantly reduced. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (FCRA). FCRA makes commitments of federal loan guarantees contingent upon prior budget appropriations ("scoring") of enough funds to cover the estimated present value cost associated with the guarantees. The present value cost is based on an estimate of the following cash flows at the time the loan guarantee is disbursed:

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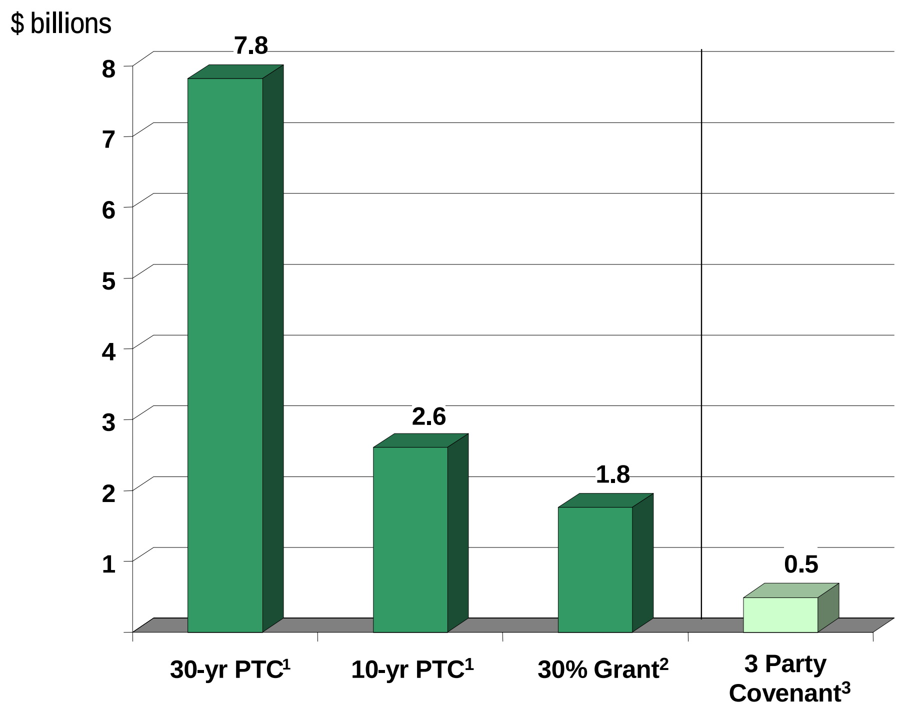
[29] The cost of capital component of energy costs on a capital intensive coal fueled generating plant is typically 60-70% of total energy costs. Substantially lower costs of capital under the 3Party Covenant, as explained in ES-5, reduce the ratepayer supported costs of IGCC to levels competitive with PC.

[30] Use of redundant gasifier capacity, which is assumed in the cost of energy assessment summarized in ES-5 below, also provides protection against operational difficulties that might otherwise reduce plant availability.

[31] This report has not attempted to quantitatively evaluate the costs or risks that ratepayers are being asked to take on, or to quantify the benefits that they will receive. Instead the paper outlines qualitatively how IGCC and the 3Party Covenant benefit ratepayers and quantifies the direct economic savings associated with 3Party Covenant financing. A comprehensive cost/benefit assessment is beyond the scope of the paper, but may be an appropriate future line of investigation.

[32]The cost risks to the ratepayer of a new IGCC plant would also be significantly diluted by the fact that the plant would constitute a small percentage of the total sources of power (generation and purchases) used by a utility. Typical large electric utilities in the U.S. have total sources of power that range between about 50 and 150 million MWh per year. (For example, in 2002 the total sources of power for Cincinnati Gas & Electric were 133 million MWh; Florida Power and Light, 105 million MWh; and PSI Energy, 63 million MWh (see EIA Form 861.) A new 550 MW IGCC facility would generate about 4 million MWh per year if operating at an 85 percent capacity factor. Therefore, in a worse case scenario, if the cost of energy from an IGCC facility ended up 20 percent more than the cost of energy of an alternative PC plant, it would represent a 0.5 to 1.6 percent increase in the overall cost of power procurement by the utility, due to the single plant's relatively small share of the total sources of power.

Figure ES-6. Federal Budget Cost of 1 cent/kWh Support for 3,500 MW of IGCC under Different Policy Approaches



[1] PTC = Production Tax Credit equal to 1.0 cent/kWh of generation (10-year PTC program provides significantly less economic benefit than the other programs that provide about 1 cent/kWh over 30 years).
[2] Federal grant equal to 30 percent of total plant investment (equivalent to 0.96 cent/kWh of economic support for 30 years).
[3] Assumes 10 percent scoring of federal guarantees (equivalent to 1.06 cent/kWh of economic support for 30 years).

1. Payments by the Government to cover defaults and delinquencies, interest subsidies, or other payments; and
2. Payments to the Government, including origination and other fees, penalties and recoveries.

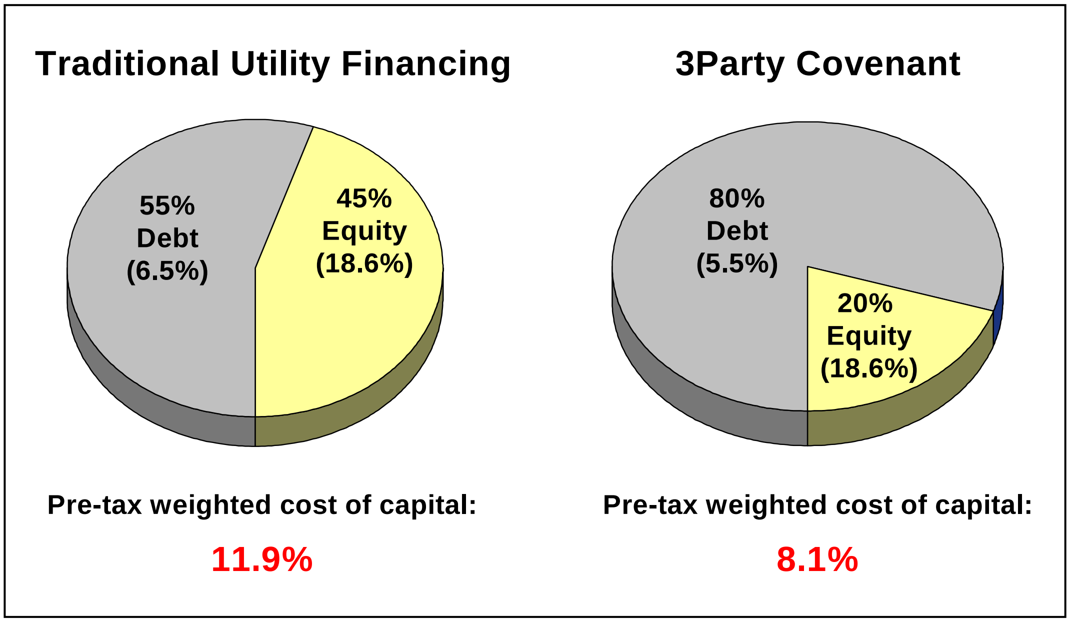
Payments by the Government are estimated based on the dollar amount guaranteed and the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors. The risk of default provides for estimation of the expected payment (the risk of default times the amount guaranteed) to make the scoring determination. The Director of the Office of Management and Budget (OMB) is charged with making this determination, but may elect to delegate the OMB's authority to another agency. To the extent the rating agencies and OMB view the 3Party Covenant as reducing the risk of default by providing a state PUC approved revenue stream, the federal budget cost (scoring) of the loan guarantees should be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, then $5 billion of loan guarantees (enough for about 3,500 MW) would cost the federal budget $500 million.

This budget impact is significantly less than alternative grant or energy production tax credit based incentive programs. As illustrated in Figure ES-6, a one cent/kWh production tax credit provided over a 30 year period (approximately the same economic benefit as provided by the 3Party Covenant) for 3,500 MW of IGCC would cost the federal government $7.8 billion, or sixteen times more than the 3Party Covenant. If provided for only 10 years, the one cent/kWh production tax credit (providing the project significantly less economic benefit than the 3Party Covenant) would still cost $2.6 billion, or more than 5 times more than the 3Party Covenant. Similarly, if a 30 percent federal grant were offered to offset IGCC capital costs, the federal budget cost would be more than 3.5 times more than the budget cost of the 3Party Covenant. The 3Party Covenant loan guarantee approach is significantly less costly to the federal government than these alternative incentive approaches and has the advantage of addressing the major financial obstacles to deployment (e.g., capital availability) that would not be addressed by a production tax credit or grant program.[33]

The 3Party Covenant program reduces the cost of energy from an IGCC power plant approximately 17 percent. The cost of energy reductions result from:

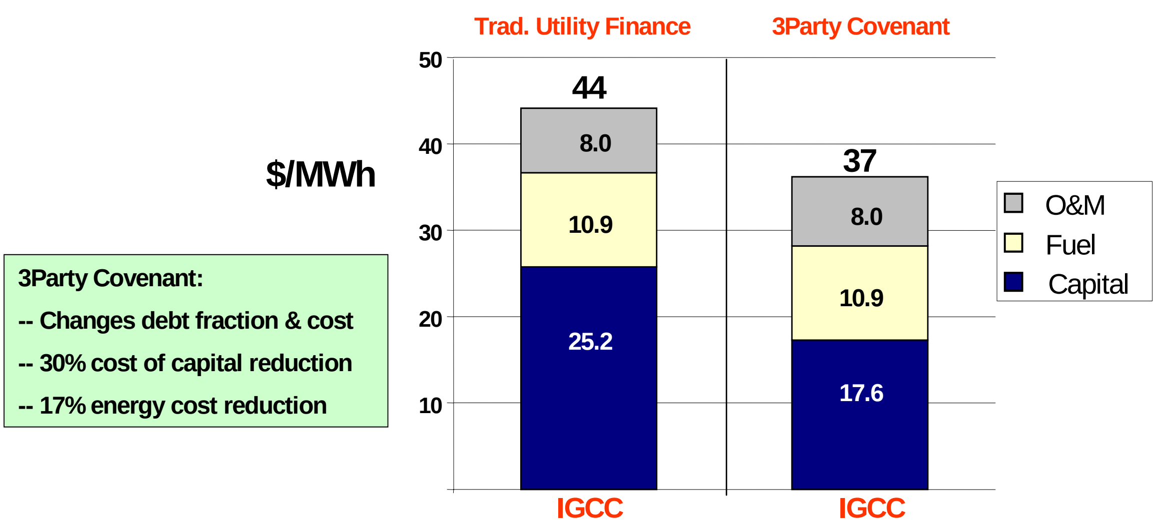
1. Providing for a significantly higher ratio of debt to equity than a traditional utility financing ratio (from 55/45 to 80/20 under the 3Party Covenant).
2. Lowering the cost of debt through the federal loan guarantee, which reduces

Figure ES-7. Cost of Capital Reduction under 3Party Covenant



[33] This is not to suggest that budget cost and capital availability are the only attributes that policy makers should consider. There may be other tradeoffs between a PTC and loan guarantee approach that policy makers may want to weigh, such as the requirements for administering the program and the risks associated with different approaches.

Figure ES-8. 3Party Covenant Impact on IGCC Cost of Energy



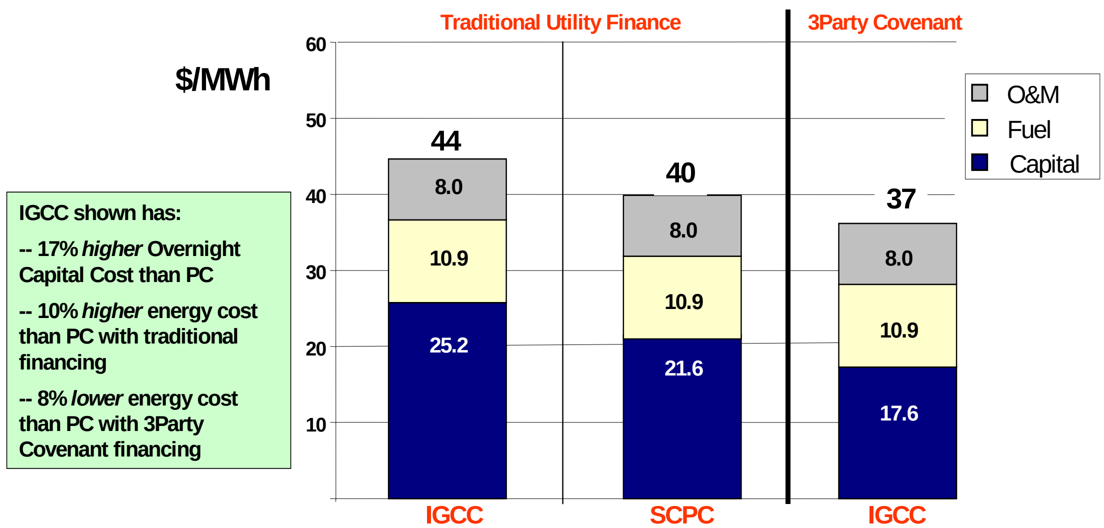
Overnight Capital Cost ($/kW)	$1,400	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25
Capacity Factor	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700
Debt Fraction	55%	80%
Debt Cost	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%

the interest charge from a typical 6.5 percent for a mid-grade utility bond to the 5.5 percent rate associated with a federal agency bond, in January 2004. Funding construction financing costs on a current basis by adding construction work in progress (CWIP) to the rate base and recovering these financing costs as they are incurred, rather than accruing these financing costs (which typically account for about 10 percent of Overnight Capital Costs) and recovering them as part of the capital investment.

As illustrated in Figure ES-7, these changes reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant over 30 percent from about 12 percent (traditional utility financing) to 8 percent (3Party Covenant). Since the cost of capital accounts for over 60% of the total cost of energy in a capital intensive coal based PC or IGCC, this change in cost of capital (along with the reduction in construction financing costs) reduces the total energy cost about 17 percent.

The impact of the 3Party Covenant is demonstrated by comparing the cost of energy associated with a reference IGCC plant financed under a traditional utility financing scenario, with the same plant financed under the 3Party Covenant. As illustrated in Figure ES-8, the reference IGCC plant financed under traditional utility financing has a

Figure ES-9. IGCC Cost of Energy versus Super-Critical PC



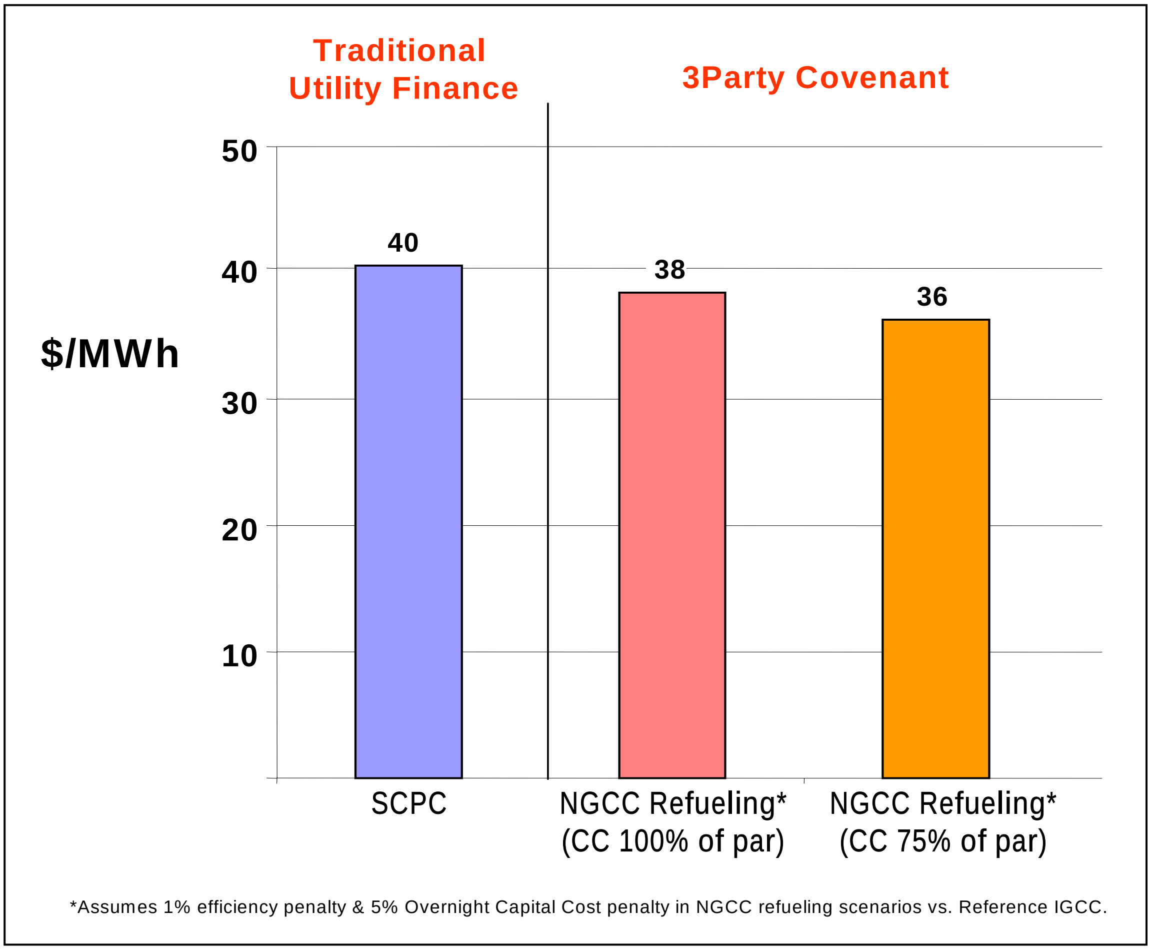
Overnight Capital Cost ($/kW)	$1,400	$1,200	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25	$1.25
Capacity Factor	85%	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700	8,700
Debt Fraction	55%	55%	80%
Debt Cost	6.5%	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%	18.6%

calculated cost of energy of 44 $/MWh, while the same plant financed under the 3Party Covenant has a cost of energy of 37 $/MWh. The 3Party Covenant reduces the cost of capital component of energy cost 30 percent and energy cost 17 percent.

Figure ES-9 illustrates how the 3Party Covenant affects the relative cost of energy of IGCC compared to PC. The figure illustrates the Reference IGCC plant assuming traditional utility financing and under the 3Party Covenant compared to a PC plant built with traditional utility financing. The figure illustrates that the Reference IGCC plant has a 17 percent higher Overnight Capital Cost than the PC plant, which results in a 10 percent higher cost of energy when both are financed traditionally. However, when 3Party Covenant financing is applied to the IGCC plant, its cost of energy is reduced to a level 8 percent below the PC plant.

Opportunities have recently emerged to create even more favorable IGCC economics by financing the refueling of distressed NGCC assets with coal gasification systems under the 3Party Covenant. Under the reference case IGCC, it is assumed that the gasifier island accounts for about 65 percent of the $1,400/kW EPC cost, or roughly $900/kW and that the combined cycle power block costs about 35 percent, or $500/kW. In a distressed NGCC refueling scenario, the combined cycle power block may be available at a significantly reduced price. If available for refueling at 75 percent of par, the cost is about $375/kW, and at 50 percent of par, it is $250/kW. If these costs are applied as the

Figure ES-10. Cost of Energy of NGCC Refueling under 3Party



combined cycle power block component of the IGCC EPC cost, the Overnight Capital Cost is reduced to $1,275/kW and $1,150/kW, respectively (well below the $1,400/kW reference case assumption).

In refueling scenarios, there is likely to be some inefficiency in design and construction of the gasification system and its integration due to retrofit requirements. For example, a $15/kW cost has been suggested by NETL for refitting the combustion turbine. Other costs might include the need for supplemental steam generation or site improvements. In addition, plant integration may be less than would be planned for a facility designed from the outset to be an IGCC, which may result in reduced efficiency. For this analysis, a five percent capital cost and one percent efficiency penalty is incorporated into the NGCC refueling scenarios to address these issues.

Figure ES-10 illustrates the cost of energy achieved in NGCC refueling scenarios assuming the combined cycle power block is contributed to the project at 75 percent of its original par value (assumed to be $500/kW). Figure ES-10 illustrates that combining 3Party Covenant financing and the potential cost savings associated with using existing distressed NGCC assets produces energy at levels below an all-new IGCC and at levels 10 percent below the reference PC plant built with traditional utility financing. Actual project savings will depend on the cost of the distressed asset to the project and the level of additional cost associated with retrofitting the combined cycle power block to work with a coal gasification system. For example, if the combined cycle power block were contributed to the project at 50% of par, the cost of energy would be about 14 percent below the traditionally financed PC, or $34.5/MWh.

ES-5. Implementation

Implementation of the 3Party Covenant requires federal legislation authorizing loan guarantees for qualifying IGCC projects. Consideration must be given to a number of implementation issues in developing legislation to ensure the program meets IGCC deployment objectives with minimal federal budget impact. Meeting deployment objectives will require determining the desired level of investment (in what timeframe), and ensuring that the economic and financial hurdles that have inhibited IGCC commercial deployment to date are adequately addressed. Section ES-7 below outlines recommended components of federal legislation for implementing the 3Party Covenant to stimulate 3,500 MW of IGCC deployment through authorization of $500 million of budget scoring appropriations to support $5 billion of federal loan guarantees.

The timing of 3Party Covenant implementation is dependent on enactment of federal legislation to establish a loan guarantee program. Proposed energy legislation debated by Congress in 2003 provided significant tax and loan guarantee incentives for clean coal technologies, including IGCC. Ongoing energy policy discussions and wide support for advancing clean coal technologies provide a window of opportunity for near term discussion and implementation. The sooner a program is put in place, the sooner the energy and environmental benefits of IGCC deployment (described in detail in Section 1 of this report) will be realized, a circumstance that should provide strong motivation for lawmakers to consider near-term legislative action.

Implementation of the 3Party Covenant also requires that states establish regulatory mechanisms for review, approval and recovery of IGCC project costs. Section 8 (Volume II) of this report, describes the status of state electric utility regulatory programs in three states with regulated retail electricity service (Indiana, Kentucky and New Mexico) and two states with competitive retail electricity markets (Ohio and Texas) to identify how the different regulatory programs affect 3Party Covenant implementation. Section 9 (Volume II) provides a model state regulatory mechanism for implementing the 3Party Covenant.

ES-6. Components of Federal Legislation for Implementing 3Party Covenant

The outline below describes recommended components of federal legislation to implement the 3Party Covenant. These components are designed to stimulate development of 3,500 MW of IGCC generation with federal loan guarantees of $5 billion. The program is targeted at stimulating deployment of IGCC technology, which is the focus of this paper. This or other incentive programs may be appropriate for IGCC and other advanced coal technologies.

<u>Purpose</u>

Establish a federal loan guarantee program that stimulates deployment of IGCC by reducing cost of capital, apportioning risk, and assisting with pre-development costs in order to:

- Support U.S. energy independence
- Promote homeland security
- Improve coal generation environmental performance
- Increase generation efficiency
- Refuel and revalue billions of dollars of financially distressed and underutilized natural gas combined cycle investments
- Reduce pressure on natural gas prices
- Provide affordable and reliable electricity supplies
- Position the U.S. as a global leader in advanced coal generation technology
- Minimize the burden to the federal budget

<u>Scope</u>

- $500 million appropriations to score up to $5 billion of federal loan guarantees for 3,500 MWs of base load capacity:
    - $450 million for scoring loan guarantees
    - $50 million revolving fund for pre-development engineering loans
    - Loan guarantees may be committed for a period of 10 years beginning with the first fiscal year the program is funded.
- Program shall be implemented through an accelerated rulemaking process to be completed within 12 months of enactment
- Program shall authorize the collection of application or other fees to cover administrative costs as well as insurance fees to the extent such fees are determined to be appropriate by the Secretary

Loan Guarantees

- Up to 80% of total plant Investment
- 30-year term, non-recourse, backed by full faith and credit of U.S. Government
- Owner contributes 20% equity investment

Qualifying Projects

- An IGCC or other coal-fueled power plant technology with the following performance characteristics:
    - Coal accounts for at least 75% of fuel heat input
    - In the case of IGCC, combustion turbine operates on syngas as primary fuel (natural gas or diesel may serve as an emergency back-up fuel only)
    - Design heat rate of 8,700 btu/kWh (HHV) or lower
    - New power plant, repowering of an existing coal power plant, or refueling of an existing natural gas combined cycle power plant
- Emissions Performance:
    - 99% sulfur reduction with SO_2 emission not to exceed 0.04 lb/mmBtu
    - NOx emissions not to exceed 0.025 lb/mmBtu
    - Particulate emissions from stack not to exceed 0.01 lb/mmBtu
    - 95% mercury emissions control
- Determination by DOE that the technology provides a technical pathway for CO_2 separation and capture and for the co-production of hydrogen slip-streams.
- To minimize federal budget scoring, qualifying projects shall have:
    - 3Party Covenant assured revenue stream through state PUC or other regulatory body providing upfront and ongoing regulatory determinations of prudence of project costs and approvals of pass-through of project costs (reflecting ongoing inclusion of approved capital investments in rate base and inclusion of approved operating costs in the cost of service, or reflecting purchased power costs incurred under a power purchase agreement) under federal and state enabling laws ("Regulatory Determinations"); or
    - Comparable credit (and budget scoring) as that provided by 3Party Covenant Regulatory Determinations, which might be created through insurance, industrial guarantees, or other credit enhancements.
- Projects shall include EPC contractor performance and delivery guarantees (full wrap) for project construction.
- Initial financing shall provide Line of Credit for additional draw of up to 15 percent of Capital Costs with an additional minimum matching equity contribution of 20 percent of the amount drawn.

- Secretary shall issue guarantees only for projects with budget scoring that does not exceed 10% of loan principal.
- Secretary shall develop criteria for issuing loan guarantee reservations (commitments prior to closing) for projects that have demonstrated feasibility and meet program qualifications

Pre-development Engineering Loans

- Non-recourse, interest-free loans shall be available for 75% of the cost of developing initial engineering and feasibility evaluations of potential projects
- Developer will be required to provide 25% cash match
- Loans not to exceed $5 million dollars
- Loans to be repaid out of long-term project loan disbursements and placed into a revolving loan fund
- Secretary shall develop criteria for selecting projects to receive Pre-development Engineering Loans, taking into account project timing, feasibility and ability to meet Project Selection Criteria (below)

Project Selection

- Secretary shall establish Project Selection Criteria, including consideration of the following elements:
    - Utilization of diverse coal supplies and types
    - Competitive electricity prices
    - Geographic diversity
    - Project feasibility
    - Financial strength of project
    - Environmental performance

1.0. WHY IGCC

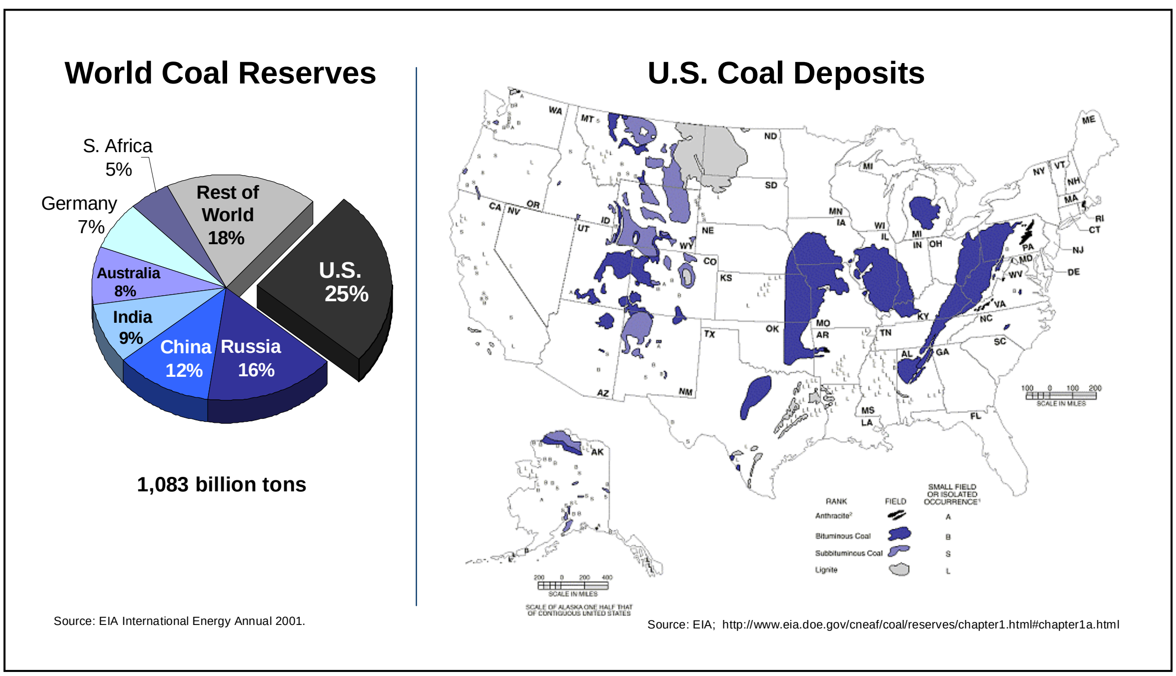
IGCC technology has the potential to substantially reduce the environmental impact of coal power plants by reducing air emissions, water consumption, and solid waste production. It also offers a technical pathway for cost effective separation and capture of CO_2 emissions and co-production of hydrogen. These environmental attributes make it an important technology for enabling the important energy, economic, and national security benefits of coal use for electricity generation to be achieved with minimal environmental impact.

1.1. Energy Independence and Security

The U.S. has more coal than any other country in the world. Estimated recoverable coal reserves in the U.S. are 275 billion tons, which is approximately 25 percent of world supplies and more than a 250-year supply at current consumption.[34] This share of world coal reserves is in sharp contrast to the U.S. share of world oil and natural gas reserves, which are estimated to be less than 2 percent and 3 percent of world totals, respectively.[35]

Coal fuels over 50% of U.S. electricity generation and is the only major fossil fuel for which the U.S. is a net exporter. In 2002, the U.S. imported 53 percent of its oil supply, which is up from 28 percent in 1972 just prior to the first Arab oil embargo. At the same

Figure 1-1. Location of U.S. Coal Reserves and Share of World Coal Supply



[34] National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003.
[35] EIA, International Energy Annual 2001, Table 8.1.

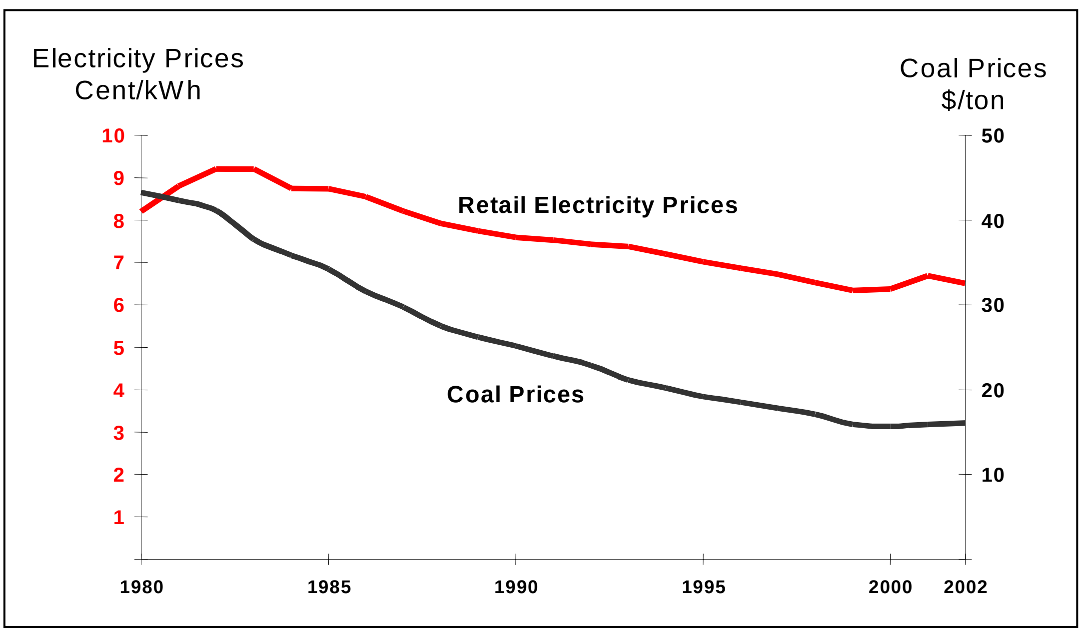
time, high natural gas prices have led major oil and gas companies to announce plans for multi-billion dollar investments in infrastructure to increase imports of liquefied natural gas (LNG) and chemicals from mid-eastern and other countries.[36] Existing dependence on foreign oil and the prospect of increased imports of natural gas are significant energy and national security concerns, particularly in the face of escalating oil and natural gas prices and continuing Middle East political turmoil.

As illustrated in Figure 1-1, U.S. coal reserves are dispersed across several regions, including states in the Appalachian, Midwest, Rocky Mountain, and Southern regions and in Alaska. Abundant domestic supplies, geographic dispersion, and transport by a vast network of railroads and barges make widespread or long-term supply disruptions unlikely. These factors also support stable prices that are unaffected by geopolitical events. The stockpiling of 30 to 90 day coal inventories at most generating plants further enhances the security of coal generation, helping protect against short-term fuel supply disruptions due to terrorism or other unforeseen events that might otherwise affect electricity supplies. These factors make coal a critical resource for fulfilling the national need for secure, reliable electricity supplies.

1.2. Economic Growth

Coal is also a low cost energy resource that helps fuel economic growth. As illustrated in Figure 1-2, real coal prices have declined 63 percent since 1980 and real retail electricity prices, which are directly affected by coal prices since coal accounts for over 50% of

Figure 1-2. Real Retail Electricity and Coal Prices



[36] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.

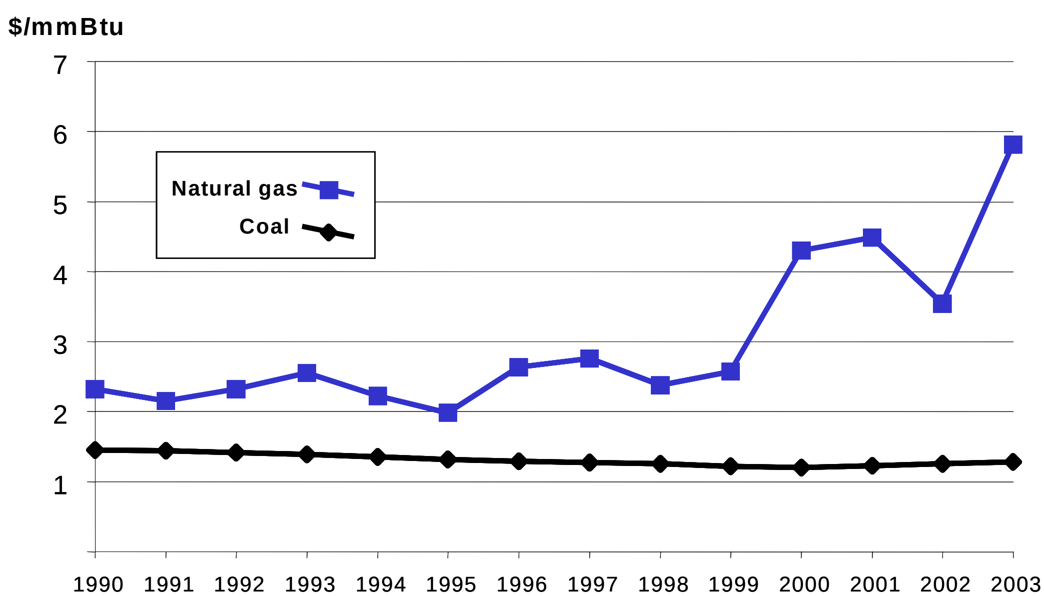
electricity generation in the U.S., have declined 21 percent over the same period. The average price of coal delivered to electric generators in December, 2003 was \$1.25/mmBtu, compared to \$3.90/mmBtu for delivered petroleum and \$5.24/mmBtu for delivered natural gas.[37] In contrast to natural gas prices, which have become increasingly volatile in recent years, coal prices have remained relatively stable and slowly declined for the past two decades. Coal price stability translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel.

Electricity is a fundamental driver of economic growth and prosperity and electricity prices affect every business and consumer in the country. Coal electricity generation has played an important role in helping the U.S. maintain low electricity prices and, because of its low cost, is projected to remain a dominant generation fuel for decades to come.

1.3. Natural Gas Prices

In contrast to coal, natural gas prices reached historically high levels in 2003 and are projected to remain high and volatile for the foreseeable future. Figure 1-3 illustrates the delivered price of natural gas and coal to electric generators in the last decade. Figure 1-3 demonstrates that natural gas prices have risen and become increasingly volatile over the past decade while, in contrast, coal prices have remained stable and slowly declined.

Figure 1-3 Average Delivered Fuel Prices to Electric Generators



Sources: 1990-2001, EIA, Electric Power Annual 2001, March 2003.
2002-2003, EIA, Electric Power Monthly, September 2003.

[37] <u>See</u> EIA, "Electric Power Monthly," April 2004, Table ES1.A.

Figure 1-4. Henry Hub Natural Gas Futures

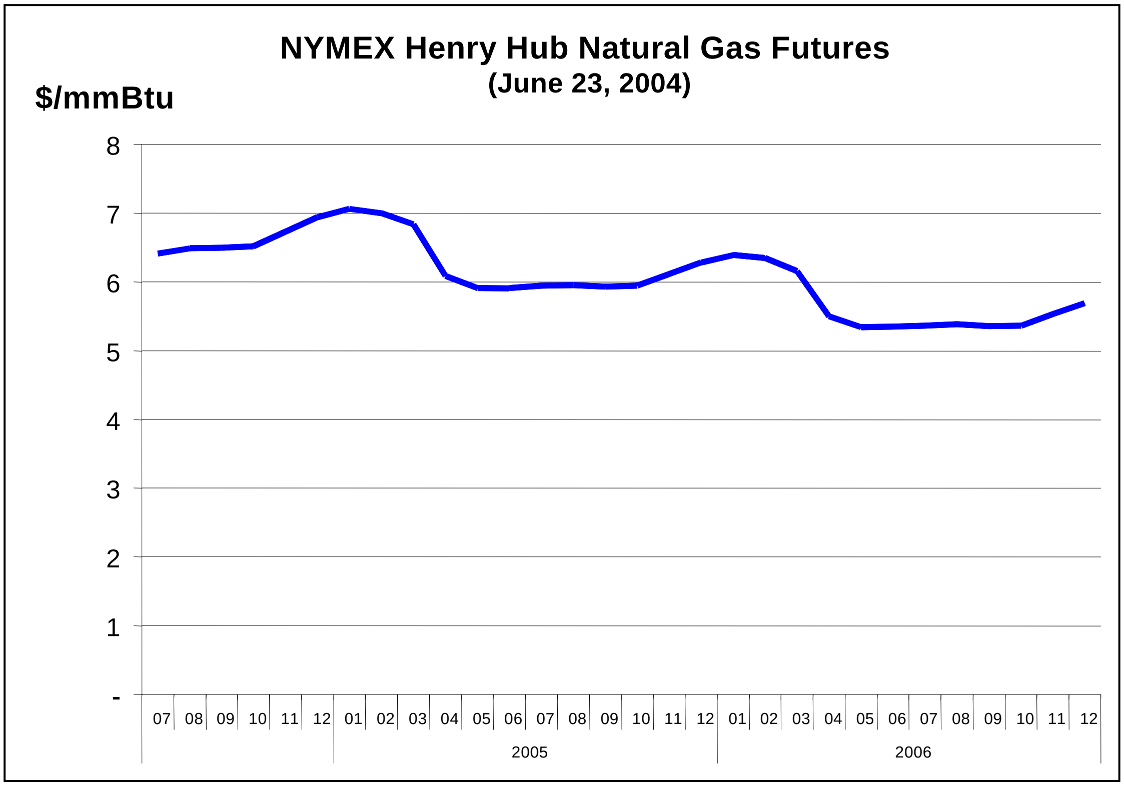


Figure 1.4 illustrates Henry Hub natural gas futures prices (delivered prices are generally $0.50-$1.00/mmBtu higher than Henry Hub prices), indicating the expectation that high prices will remain through at least 2006.

High natural gas prices have caused widespread, adverse impacts on the U.S. economy and economic competitiveness. These impacts were described by the House Speaker's Task Force for Affordable Natural Gas:

> Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries.[38]

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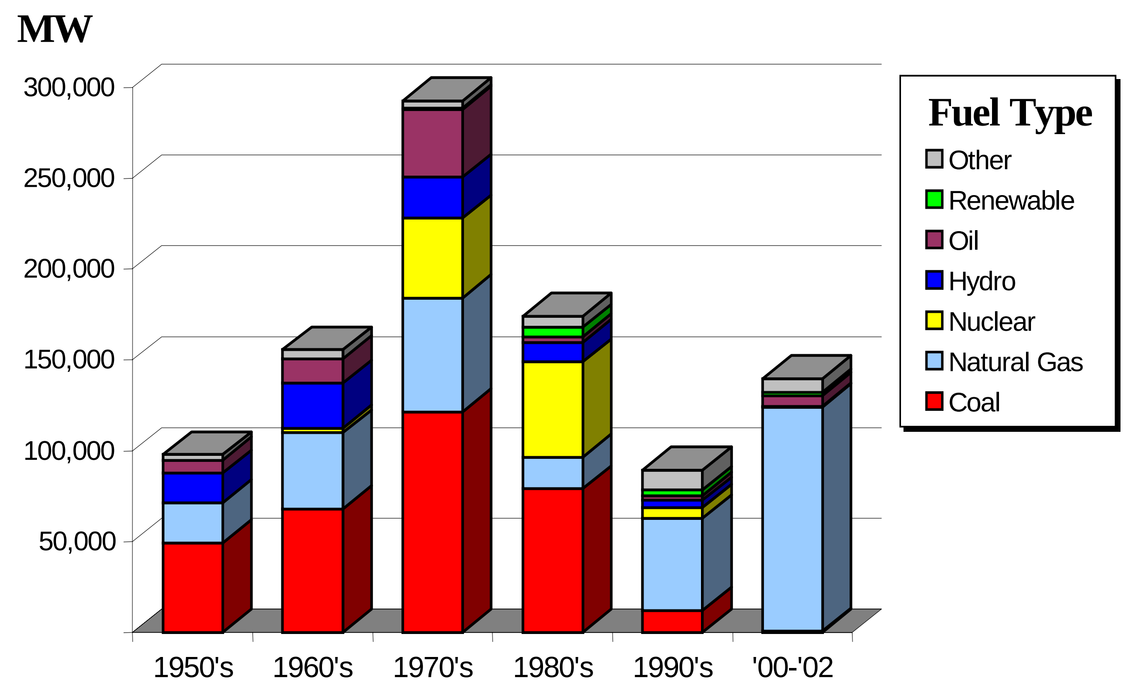
[38] House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (Sept. 30, 2003). Alan Greenspan, Chairman of the Federal Reserve System, also testified about natural gas prices in 2003, stating: "The long-term equilibrium price for natural gas in the United States has risen persistently during the past six years from approximately $2 per million Btu to more than $4.50…The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. Unless this competitive weakness is addressed, new investment in these technologies will flag." Testimony of Chairman Alan Greenspan before the Committee on Energy and Natural Resources, U.S. Senate (Jul. 10, 2003).

Figure 1-5. U.S. Electric Generation Capacity Additions by On-line Date



Source: Form EIA 860 "Annual Electric Generator Report," 2001.

High natural gas prices also hurt consumers that are dependent on natural gas to heat their homes and can create compounding price increases when they translate into higher electricity prices. High natural gas prices in 2003, combined with a softening of wholesale electricity markets, also caused many of the natural gas power plants built in recent years to become uneconomic and decrease in value to a fraction of their original cost.[39] As discussed below in Section 3.4, IGCC technology provides a means of both recapturing the value of these facilities and reducing natural gas demand by refueling some of these existing plants with coal gasification systems.

One factor supporting high natural gas prices and price forecasts is the increased demand resulting from construction of new natural gas-fired electric generation. Figure 1-5 illustrates the new electric generating capacity that came on-line in the U.S. each decade from the 1950's through the 1990's, as well as in the three-year period from 2000 to 2002. Figure 1-5 illustrates that more coal capacity was added than any other type of generation in the 1950's through the 1980's, accounting for between 41 and 50 percent of new generating capacity each decade. However, since 1990, less than 6 percent of new capacity has been coal-fueled, while over 75 percent of the new capacity is natural gas-fired. In the last three years, 140,000 MW of new generating capacity was added (more

[39] For example, on May 4, 2004, Duke Energy announced the sale of 5,325 MW of eight natural gas-fired power plants in the Southeast U.S. for $475 million, or about $90/MW, which is less than one-fifth of their original cost.

than the total combined capacity of U.S. nuclear power plants) and over 90 percent of it is natural gas-fired.[40]

According to EIA, natural gas consumption by electric generators increased 40% between 1997 and 2002.[41] In addition, EIA's Annual Energy Outlook 2004 predicts that natural gas demand from electric generators will increase another 51% by 2025.[42] Increasing natural gas demand from electric generators puts additional pressure on natural gas supplies and prices. Commercial deployment of IGCC technology could help reduce growth in natural gas demand from electric generators and, if deployed to refuel existing natural gas combined cycle systems (See Section 3.4 below), directly reduce demand to help alleviate price pressures affecting other sectors of the economy. Unlike natural gas, increased use of coal for electricity generation has very little impact on other sectors of the economy because coal use in the U.S. is essentially dedicated to electricity generation, with 90 percent of coal consumption attributable to electric generators.[43]

1.4. Air Pollutant Emissions

Air pollutant emissions are a serious environmental concern associated with coal power generation. The most problematic emissions include sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury (hg), and carbon dioxide (CO_2). These emissions contribute to both localized air pollution problems and global climate change concerns. Localized air pollution issues include ground-level ozone pollution (involving NOx), fine particulates (NOx and SO_2), acid rain (NOx and SO_2), regional haze (NOx and SO_2), mercury deposition (Hg), and eutrophication of lakes and streams (NOx).[44] Globally, CO_2 emissions are a greenhouse gas emitted from fossil fuel combustion linked to climate change concerns. In the U.S., these environmental issues have lead to a number of legislative and regulatory programs aimed at reducing emissions from existing coal-fired power plants, stringent requirements for new facilities, and consistent opposition by environmental organizations and others to the permitting of new coal-fired power plants.[45]

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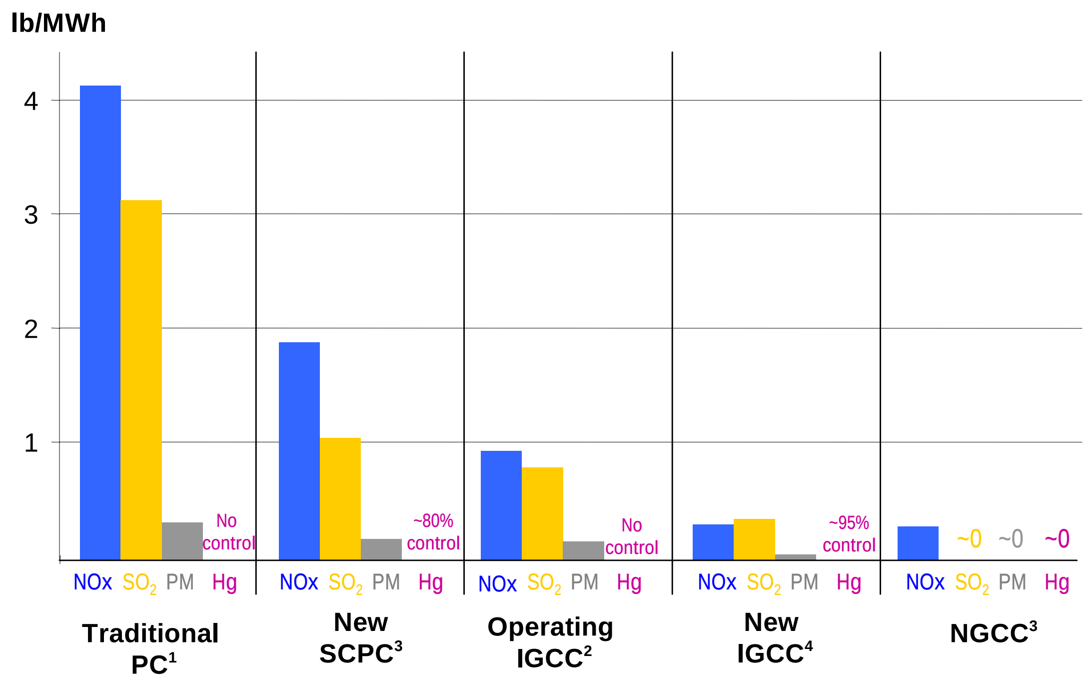
[40] See Form EIA 860 "Annual Electric Generator Report."
[41] See http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm
[42] EIA, Annual Energy Outlook 2004, Table A-13.
[43] EIA, "Annual Energy Outlook 2003 (AEO 2003)," Jan. 2003 (Table A16).
[44] See EPA, "Latest Findings on National Air Quality: Status and Trend," Aug. 2003. See also EPA, "Nitrogen: Multiple and Regional Impacts," Feb. 2002; See also EPA, Mercury Study Report to Congress, Dec. 1997.
[45] For a discussion of issues associated with power plant emissions and efforts to address them, see Testimony of Jeff Holmstead Before the Committee on Environment and Public Works, U.S. Senate, Nov. 1, 2001, http://www.epa.gov/air/clearskies/nov1.pdf.

Figure 1-6. Estimated Emissions Performance



[1] Based on typical performance levels.
[2] Based on emissions performance of four operating IGCC facilities provided in NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, December 2002;
[3] Based on emissions levels in EPRI/NETL, *Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal*, Dec. 2002, SCPC and NGCC 7FA base cases.
[4] Levels proposed for qualification in 3 Party Covenant federal incentive program. Based on performance characteristics provided in NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, December 2002; and performance estimates from Eastman Chemical Company.

IGCC technology offers the potential for significantly improved air emissions performance for coal-fueled power plants to address many of the environmental concerns associated with coal generation. IGCC power plants achieve emissions reductions primarily through the syngas cleanup processes, which occur prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases.[46] Because syngas has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions. In IGCC plants, virtually all of the particulates, nitrogen and sulfur compounds, and 95-99 percent of the mercury, are removed from syngas before it is directed to the combustion turbine. As a result, the PM, NOx, SO_2 and mercury emissions resulting from syngas combustion in the turbine are significantly

[46] Typical combustion and post-combustion controls required of new PC power plants include Flue Gas Desulfurization (FGD, or "scrubbers") for SO_2 control, low NOx burners and Selective Catalytic Reduction (SCR) for NOx control, and Electro-Static Precipitators (ESP) or fabric filter baghouses for particulate

lower than the emissions produced by direct combustion of coal in PC boilers. Figure 1-6 illustrates the IGCC emissions performance expected for the next generation of plants for NOx, SO_2, Particulate matter and mercury compared to traditional PC, new super-critical PC, and NGCC plants.

1.41. SO_2 Emissions

High-temperature gasification of coal produces hydrogen sulfide (H_2S) and small amounts of carbonyl sulfide (COS). The amount of these acid gases in the syngas is a function of the amount of sulfur in the coal. Prior to combustion, IGCC systems remove these sulfur compounds from the syngas through acid gas clean-up processes, including chemical solvent-based processes (using MDEA) and physical solvent-based processes such as Selexol™ and Rectisol™.[47] Sulfur recovery processes recover sulfur either as sulfuric acid or as elemental sulfur, which are commercial by-products. These processes are able to remove over 99 percent of sulfur. The small amount of residual sulfur in the syngas after cleaning is converted to SO_2 in the combustion turbine, which accounts for the low levels of SO_2 emissions from IGCC facilities.[48]

Existing IGCC power plants achieve SO_2 emissions performance that is significantly better than pulverized coal power plants. The existing IGCC facilities in the U.S. achieve emissions levels around 0.13 pounds per million Btu (lbs/mmBtu), compared to the federal New Source Performance Standard (NSPS) for coal power plants of 1.2 lbs/mmBtu. The next generation of IGCC power plant is expected to achieve even lower SO_2 emissions, achieving 99 percent or greater sulfur removal. It is recommended that to qualify for a 3Party Covenant financing program, IGCC facilities achieve 99 percent sulfur removal and emissions rates not to exceed 0.04 lb/mmBtu (see Appendix A).

1.42. NOx Emissions

Fossil fuel combustion produces NOx emissions through both fuel bound nitrogen and thermal formation at high temperature. Coal contains chemically bound nitrogen that accounts for over 80 percent of the total NOx emissions from PC power plants.[49] In contrast, acid gas clean-up processes in IGCC plants remove over 99 percent of the nitrogen compounds from the syngas prior to combustion, so NOx formation in IGCC plants is primarily the result of thermal NOx produced in the turbine combustor. By maintaining a low fuel to air ratio (lean combustion) and adding a dilutent such as steam,

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control. These technologies add to the capital cost, size and complexity new PC power plants and decrease plant efficiency because of their energy consumption.

[47] Id.

[48] See Id., p. 2-7.There may also be very small amounts of SO_2 emissions associated with tail gas incineration as part of the sulfur recovery system and syngas flare during gasifier startup or backdown.

[49] NETL, Major Environmental Aspects, p. 2-8.

the turbine flame temperature can be lowered and thermal NOx formation resulting from IGCC generation significantly reduced.[50]

Current state-of-the-art combustion control for syngas-fired turbines enables them to achieve NOx emissions as low as 15 ppm (about 0.075 lb/mmBtu). At this level, they can achieve lower emissions than allowed under the NSPS for coal power plants of 1.6 lb/MWh, or 0.15 lb/mmBtu (about 25 ppm for a gas turbine) and do so without the use of post-combustion NOx controls such as selective catalytic reduction technology (SCR). Turbines firing syngas are not able to use the so-called Lean-Premix Technology for reducing NOx formation in combustion turbines that can be used when firing natural gas to achieve NOx emissions levels as low as 9 ppm.[51]

However, IGCC technology offers the potential to achieve NOx emissions levels comparable with natural gas fired facilities (2 or 3 ppm (0.01 lb/mmBtu)) through the use of post-combustion Selective Catalytic Reduction (SCR). SCR is a commercially available NOx control technology in wide use on natural gas-fired CTs and coal boilers. To deploy SCR technology on IGCC facilities where syngas is the fuel, very deep sulfur removal from the syngas is required (99+ percent sulfur removal) prior to combustion to prevent fouling and corrosion of heat transfer surfaces in the HRSG by ammonium sulfate salts. This deep level of sulfur removal to accommodate SCR use can be achieved with several sulfur removal processes, including Selexsol™, Rectisol™, or the addition of a zinc oxide or activated carbon polishing reactor, but adds to the cost of IGCC NOx control. It is estimated that the additional cost of deploying SCR with deep sulfur removal on IGCC is around $100/KW of capital and increases the cost of energy from an IGCC facility about 4 mills/kWh.[52] None of the commercially demonstrated IGCC facilities operating today employs post-combustion SCR controls, but it is recommended that to qualify for a 3Party Covenant financing program, IGCC emissions levels not exceed 0.025 lb/mmBtu (~5 ppm), which is a level that will require SCR controls (see Appendix A).

1.43. Particulate Emissions

Particulate control in IGCC plants begins with the gasification processes itself, which allows only small amounts of fly ash to end up in the syngas, because most of it is removed in the gasification process as slag or bottom ash. The fly ash that does end up in the syngas is in a relatively small volume of gas (relative to the volume of gas created from fuel combustion), so particulate removal with filters and/or water scrubbers is highly efficient. Additional particulate removal also occurs in the gas cooling operations

[50] Id., p. 2-9.
[51] Because of the high flame speed of H_2 in syngas, use of this technology raises the risk of damaging flashbacks. See Id.
[52] See, Gray, David and Glen Tomlinson, "Cost & Technical Issues Associated with use of SCR for NOx Removal in Coal-Based IGCC," Presented at the Gasification Technologies Conference, San Francisco, CA, October 2002.

and in the acid gas clean up systems. For these reasons, very little ash remains in the syngas sent to the turbine and IGCC facilities are able to achieve very low particulate emissions levels.[53]

The existing IGCC power plants operating in the U.S. today achieve particulate emissions rates around 0.01 lbs/mmBtu, half or less than the NSPS level for coal plants of 0.03 lbs/mmBtu. It is recommended that to qualify for a 3Party Covenant financing program, IGCC PM stack emissions levels not exceed 0.01 lb/mmBtu.

1.44. Mercury Emissions

In addition to its ability to reduce currently regulated pollutants, IGCC technology also lends itself to cost-effective mercury control to levels beyond what can be achieved with current PC technology. Mercury is a toxic, persistent pollutant that accumulates in the environment and food chain. Coal combustion power plants are the largest anthropogenic sources of mercury emissions in the U.S. Power plant mercury emissions are currently unregulated, but EPA has proposed coal power plant mercury regulations that are scheduled to be finalized by Spring 2005 and implemented in the 2007-2010 timeframe.

Currently, there is no single proven technology that can uniformly control mercury from PC power plants in a cost-effective manner, while consistently achieving mercury removal levels of 90 percent.[54] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (up to 99 percent) mercury control with established technology.[55] For example, Eastman Chemical operates a GE Energy Gasification Technologies ("GE Energy")[56] gasifer at its Kingsport, Tennessee facility that utilizes activated carbon-based technology to achieve 90-95 percent mercury removal.[57] There is also commercial experience removing virtually all (99.99 percent) of the mercury from natural gas and it is believed that comparable results are possible using similar technology for IGCC applications.[58]

A 2002 study sponsored by NETL indicates that the capital cost of 90 percent mercury removal from an IGCC plant is only $3.34 per kilowatt (much less than one percent increase) and that the total cost of energy increase is about 0.25 mills/kWh, or about $3,500 per pound of mercury removal.[59] This is about one-tenth the cost of 90 percent mercury removal from PC boilers, which was estimated in EPA's Mercury Study Report to Congress to be over 3 mills/kWh, or $37,800 per pound of mercury.[60] Other studies

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[53] Id., p. 2-7—2-8.
[54] NETL, "The Cost of Mercury Removal in an IGCC Plant," Sept. 2002, p. 1.
[55] Id.
[56] Formerly the Texaco Gasification Process, which was acquired by GE Energy Gasification Technologies July 1, 2004.
[57] Id., p. 5.
[58] Id.
[59] Id., p. 1-2.
[60] EPA, "Mercury Study Report to Congress: Volume VIII, An Evaluation of Mercury Control Technologies and Costs," EPA-452/R-97-010, Dec. 1997, p. 3-6.

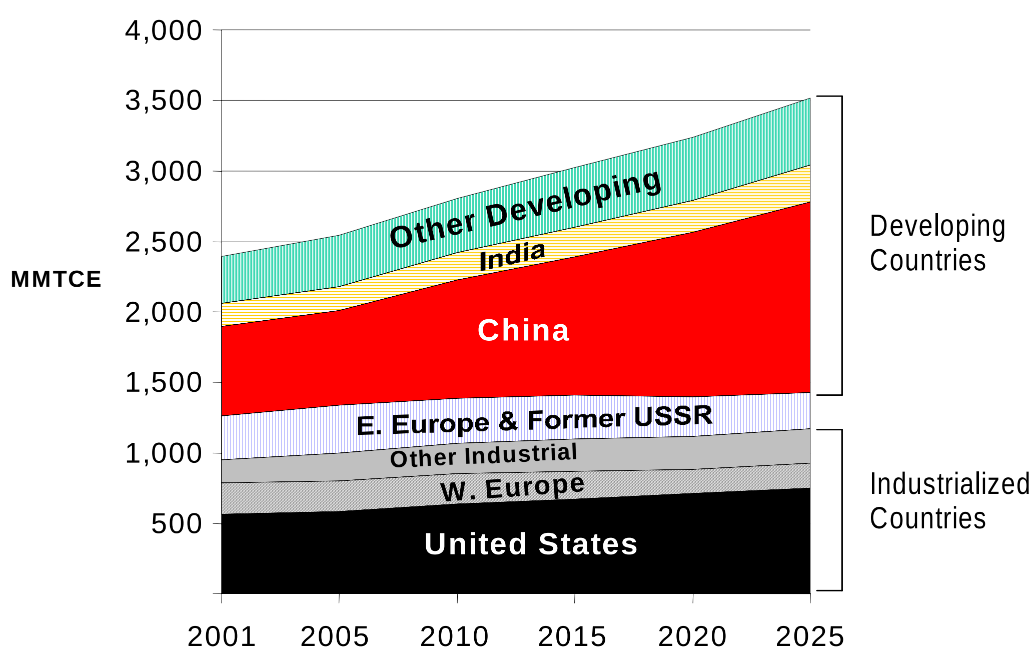
have found IGCC mercury removal costs as low as $1,200-$1,300 per pound[61] and mercury removal from flue gas at PC plants as much as $85,000 per pound,[62] which would suggest PC mercury removal may cost as much as 65 times more than IGCC mercury removal. It is recommended that to qualify for a 3Party Covenant financing program, IGCC facilities achieve at least 95 percent mercury removal.

1.5. Climate Change

IGCC commercialization and deployment could also provide a technical pathway for coal generation in a carbon constrained world. Coal has the highest carbon content of any fossil fuel. Nonetheless, both industrialized and developing countries are projected to continue to depend on coal as a primary energy source and continue to build and re-power coal-fired power plants to meet rapidly increasing electricity demand. Continued and expanded coal combustion with conventional generating technologies will substantially increase worldwide CO_2 emissions and exacerbate global climate change concerns.

In 2001, worldwide coal consumption was 5.26 billion short tons. It is projected to grow

Figure 1-7. Projected World CO_2 Emissions from Coal Consumption



EIA, International Energy Outlook 2003, Table A-13, p.194.

[61] Klett, M.G., and M.D. Rutkowski, The cost of mercury removal in an IGCC plant, letter report to NETL, December, 2001.

by 1.5 percent per year and reach 7.48 billion tons by 2025. Currently, about 37 percent of anthropogenic CO_2 emissions worldwide are attributed to coal combustion (2.427 billion metric tons carbon equivalent).[63] As illustrated in Figure 1-7, world CO_2 emissions from coal use are projected to increase 45 percent by 2025.[64] Essentially all the increase in world CO_2 emissions from coal is attributed to projected growth in coal-fired electricity generation. Adopting IGCC and other technologies that facilitate coal use with reduced or eliminated carbon emissions will be critical to stabilizing atmospheric CO_2 concentrations linked to climate change.

IGCC technology has several advantages over PC power plants for addressing CO_2 emissions. First, IGCC facilities have the ability to operate at higher efficiencies. Although current IGCC power plants typically operate with efficiencies that are comparable to new PC plants (35-42 percent efficiency), IGCC has many processes where efficiency could be improved through commercial optimization, including turbine designs, gas clean-up, and air separation systems. The next generation of IGCC facilities is expected to achieve efficiencies of 40-45 percent and over the longer-term reach efficiencies of 45-50 percent with advanced turbines (and as high as 70 percent with fuel cells). Greater efficiency means that more electricity is produced for every ton of coal consumed and that fewer byproduct CO_2 emissions are produced per MWh of generation.[65]

Second, IGCC technology offers the potential for separating and capturing CO_2 emissions to achieve emissions reductions more efficiently than current combustion technologies.[66] The advantage stems from the ability to remove CO_2 from syngas prior to combustion, rather than exhaust gas after combustion. Capturing CO_2 in an IGCC facility involves adding shift reactors to the syngas treatment system after the particulate and sulfur removal processes (but before combustion in the turbine), or using shift reactors and clean-up processes to remove CO_2 and sulfur compound simultaneously. Shift reactors serve to further increase CO_2 concentrations in the syngas (up to about 40 percent), which combined with the elevated pressure, allows for the use of physical absorption processes to capture CO_2, rather than more energy intensive chemical absorption processes required to remove CO_2 from PC or other combustion facility exhaust gas.[67]

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[62] EIA, "Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants," SR/OIAF/2001-04, September, 2001.

[63] EIA, International Energy Outlook 2003, Table A-10, p.191

[64] EIA, International Energy Outlook 2003, Table A-13, p.194.

[65] CO_2 emissions levels can be different for different gasification IGCC technologies. For example, dry feed gasifiers and gasifiers with heat recovery tend to be most efficient, which results in less CO_2 per MWh.

[66] Although capturing CO_2 is only the first step in controlling it (because it must be sequestered if emissions are to be reduced), most experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal power plant would be in a position to sequester its CO_2. Sequestration is not specifically addressed in this paper because it is viewed by the authors as beyond the scope of commercialization of a small initial fleet of IGCC plants, which is the objective of the 3Party Covenant proposal.

[67] NETL, Major Environmental Aspects, p. 2-45—2-47.

A joint engineering assessment by NETL and EPRI has demonstrated the economic advantages of capturing CO_2 from IGCC facilities vs. PC or natural gas combined cycle (NGCC) plants. The first advantage is in parasitic energy consumption. Much less energy is needed to capture concentrated, pressurized CO_2 in the syngas stream with physical absorption than is needed to capture it in exhaust gas at ambient pressure with chemical absorption. The NETL/EPRI study estimates that the parasitic power loss associated with CO_2 capture at IGCC facilities is about 5 percent of net plant output, compared to 21 percent for NGCC and 28 percent for PC.[68] The second advantage is lower capital cost to deploy CO_2 capture technologies. The NETL/EPRI study estimates that CO_2 capture increases IGCC capital costs about 30 percent compared to 90 percent and 73 percent for NGCC and PC, respectively. Finally, in a cost of energy comparison, the study found that IGCC with CO_2 capture produced electricity at 1.4-1.8 cent/kWh (20 percent) less than PC plants with CO_2 capture technology and less than NGCC plants with CO_2 control when gas prices exceed $4/mmBtu.[69]

Jeremy David and Howard Herzog at MIT had similar findings. David and Herzog found that the incremental cost of adding CO_2 capture to a PC plant was between 2.16 and 3.32 cent/kWh, while the incremental cost of capture at an IGCC plant was between 1.04 and 1.70 cent/kWh. With current technology and conventional financing, they found that the cost of energy from an IGCC with CO_2 capture is 6.69 cents/kWh versus 7.71 cents/kWh for PC with CO_2 capture.[70] Under the 3Party Covenant financing plan, energy costs with CO_2 removal are lower because of the lower cost of capital (<u>See</u> Section 5.5 below).

Third, IGCC technology provides a foundation for moving toward advanced hydrogen technologies such as fuel cells and zero emissions fossil-fuel power generation that may ultimately provide the keys to addressing global climate change. The Department of Energy's FutureGen and Vision 21 programs aim to develop technologies of the future that will provide for coal-fueled facilities that are 60 percent efficient and have zero emissions. Gasification is a foundation technology for achieving these goals because it can produce pure hydrogen, which can be used in fuel cells for electricity generation and to power fuel cell vehicles.

How much expanded coal use in the world impacts the environment and global climate will hinge on international technology choices, which will be significantly influenced by technology development and deployment in the U.S. Deployment of IGCC technology in the U.S. will facilitate continued and expanded coal use for energy supply and security reasons, while achieving significant environmental improvement, including progress toward cost-effective capture of CO_2 emissions.

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[68] <u>Id.</u>, citing DOE—EPRI Report 1000316, Dec. 2000.
[69] <u>Id.</u>
[70] Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.

1.6. Water Use and Solid Waste Byproducts

Although air emissions are generally considered the most significant environmental concern associated with coal power generation, water use and discharge and solid waste production are also important environmental considerations. IGCC facilities use water for the plant's steam cycle as boiler feedwater and cooling water and for other processes such as emissions control. However, because the steam cycle of IGCC plants typically produces less than 50 percent of the power output, IGCC has an inherent advantage over PC boilers in the amount of water required. On an output basis, IGCC generally requires 30 percent to 60 percent less water than PC boilers.[71] Most process water in an IGCC facility is recycled to the plant, which minimizes consumption and discharge. Several processes can be used to remove dissolved gases and solid contaminants to ensure discharge water meets environmental requirements.

The largest solid waste from IGCC facilities is typically slag, which is a black, glassy, sand-like material. Because it is highly non-leachable, it can be sold as a by-product for applications such as asphalt paving aggregate, construction backfill, or landfill cover. The other significant sold waste is sulfur, or, depending on the gas cleanup system used, sulfuric acid. The sulfuric acid is generally about 98 percent pure and the sulfur by-product is typically greater than 99.99 percent pure. Both are valuable by-products that can be sold in existing markets such as fertilizer production.[72]

[71] NETL, Major Environmental Aspects, p. 2-4—2-5.
[72] Id.

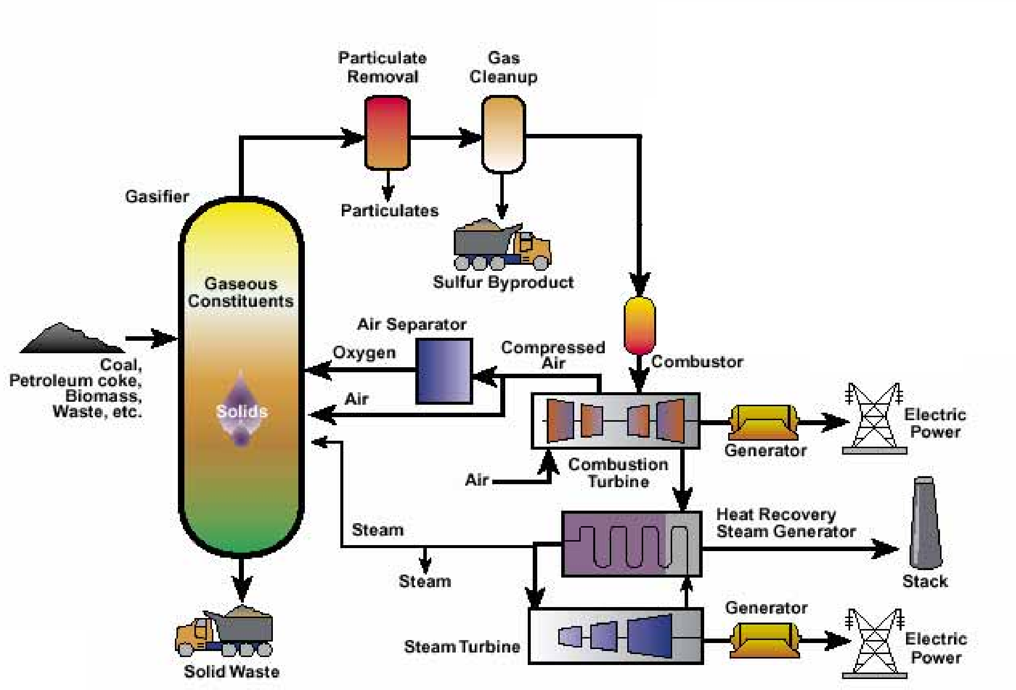
2.0. IGCC TECHNOLOGY AND OPERATING EXPERIENCE

IGCC is a power generation process that integrates a gasification system with a combustion turbine combined cycle power block. The gasification system converts coal (or other solid or liquid feedstocks such as petroleum coke or heavy oils) into a gaseous syngas, which is composed of predominately hydrogen (H_2) and carbon monoxide (CO). The combustible syngas is used to fuel a combined cycle generation power block to produce electricity. Figure 2-1 provides a simple diagram of the major components of an IGCC power plant.

Most of the components and the majority of the costs of IGCC power plants are associated with processes that are already in wide commercial use in the power, refining, or chemicals industries. For example, the combined cycle generation power block of an IGCC employs the same turbine and heat recovery technology that is used extensively around the world to generate electricity with natural gas. Only minor adjustments are needed when syngas is used as a fuel instead of natural gas.[73]

Similarly, the core process of gasification involves technology that has been used to create fuels since before World War II and has been deployed extensively around the

Figure 2-1. IGCC Power Plant



Source: NETL

[73] These adjustments are largely associated with the piping and control values that feed the syngas to the combustion turbine. Adjustment is required due to the larger volumetric flow of gas to the turbine when syngas is the fuel because it has a lower volumetric heating value than natural gas. See discussion in Section 2.15 below.

world in refining, chemical, and power applications. For example, in the 1930's Lurgi developed a dry-ash gasifier to produce Town Gas and later chemicals,[74] and during World War II, gasification was used extensively by Germany (as well as Britain and France) to produce fuel in the face of scarce oil supplies.[75]

Today, gasification remains a widely used commercial technology. A 1999 survey by the Department of Energy (DOE) and Gasification Technologies Council identified 161 commercial gasification plants in operation, under construction, or in planning and design stages in twenty-eight countries around the world.[76] These projects represented a total of 414 gasifiers with a combined syngas production capacity equivalent to 33,000 MW of power if it were all used to generate electricity.[77] Of these projects, 128 were identified as active-real projects (operating or under construction) that included 366 gasifiers.[78] There are at least fifteen suppliers of commercial gasification technology.[79] Table 2.1 lists the largest commercial gasification projects operating or under development around the world as of January 2000. China has recently ordered 10 new coal gasification plants from Shell to produce fuels and chemicals.

Despite the worldwide commercial use and acceptance of gasification processes and combined cycle power systems, IGCC is not perceived to be a mature technology. Each major component of IGCC has been broadly utilized in industrial and power generation applications, but the integration of a gasification island with a combined cycle power block to produce commercial electricity as a primary output is relatively new. This integration for commercial electricity generation has been demonstrated at a handful of facilities around the world, but is not yet perceived to be a mature, commercial technology with clearly understood costs and risks. Overcoming this perception through deployment of an initial fleet of IGCC plants is an important objective of the 3Party Covenant proposal.

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[74] NETL, Major Environmental Aspects of Gasification-Based Power Generation Technology, Dec. 2002, p. 1-8.

[75] See ARTES Institute, University of Flensburg, "Biomass Gasification Technology and Utilization, Gasification History and Development," http://members.tripod.com. See also Becher, Peter W. PHD, "The Role of Synthetic Fuel in World War II Germany," Aug., 2001, http://www.airpower.maxwell.af.mil/airchronicles/aureview/1981/jul-aug/becker.htm.

[76] NETL/Gasification Technology Council, "Gasification: Worldwide Use and Acceptance," January 2000, p. 6.

[77] Id.

[78] Id.

[79] NETL, Major Environmental Aspects, p. 1-19.

Table 2.1. 30 Largest Commercial Gasification Projects by Syngas Output

Owner	Location	Gasification Technology	Syngas Output (MW_{th})*	Online Year	Feedstock	Products
Sasol-II	South Africa	Lurgi Dry Ash	4,130	1977	Subbit. Coal	FT liquids
Sasol-III	South Africa	Lurgi Dry Ash	4,130	1982	Subbit. Coal	FT liquids
Repsol/Iberdrola	Spain	GE Energy	1,654	2004[a]	Vac. residue	Electricity
Dakota Gasification Co.	U.S.	Lurgi Dry Ash	1,545	1984	Lignite & ref res	Syngas
SARLUX srl	Italy	GE Energy	1,067	2000[b]	Visbreaker res	Electricity & H_2
Shell MDS	Malaysia	Shell	1,032	1993	Natural gas	Mid-distallates
Linde AG	Germany	Shell	984	1997	Visbreaker res	H_2 & methanol
ISAB Energy	Italy	GE Energy	982	1999[b]	asphalt	Electricity & H_2
Sasol-1	South Africa	Lurgi Dry Ash	911	1955	Subbit Coal	FT liquids
Total France/ edf /GE Energy	France	GE Energy	895	2003[a]	Fuel oil	Electiricty & H_2
Shell Nederland	Netherlands	Shell	637	1997	Visbreaker res	H_2 & electricity
SUV/EGT	Czech Republic	Lurgi Dry Ash	636	1996	Coal	Elec. & steam
Chinese Pet Corp	Taiwan	GE Energy	621	1984	Bitumen	H_2 & CO
Hydro Agri Brunsbuttel	Germany	Shell	615	1978	Hvy Vac res	Ammonia
Global Energy	U.S.	E-gas	591	1995	Bit. Coal/ pet coke	Electricity
VEBA Chemie AG	Germany	Shell	588	1973	Vac residue	Ammonia & methanol
Elcogas SA	Spain	PRENFLO	588	1997	Coal & pet coke	Electricity
Motiva Enterprises	U.S.	GE Energy	558	1999[b]	Fluid petcoke	Electricity
API Raffineria	Italy	GE Energy	496	1999[b]	Visbreaker res	Electricity
Chemopetrol	Czech Republic	Shell	492	1971	Vac. residue	Methanol & Ammonia
NUON	Netherlands	Shell	466	1994	Bit Coal	Electricity
Tampa Electric	U.S.	GE Energy	455	1996	Coal	Electricity
Ultrafertil	Brazil	Shell	451	1979	Asphalt res	Ammonia
Shanghai Pacific Chemical Corp	China	GE Energy	439	1995	Anthracite coal	Methanol & Town gas
Exxon USA	U.S.	GE Energy	436	2000b	Petcoke	Electricity & syngas
Shanghai Pacific Chemical Corp	China	IGT U-Gas	410	1994	Bit Coal	Fuel gas & Town gas
Gujarat National Fertilizer	India	GE Energy	405	1982	Ref residue	Ammonia & methanol
Esso Singapore	Singapore	GE Energy	364	2000	Residual Oil	Electricity & H2
Quimigal Adubos	Portugal	Shell	328	1984	Vac residue	Ammonia

[a] Plant was in advanced engineering at time of survey.
[b] Plant was under construction at time of survey.
* MWth is a measure of syngas thermal energy.

Source: NETL/Gasification Technology Council, “Gasification: Worldwide Use and Acceptance,” Jan. 2000, p. 7.

2.1. Major Components of IGCC Power Plants

The major components of coal-fueled IGCC power plants include: coal handling equipment, gasifier, air separation unit, gas cooling and clean-up processes, and combined cycle power block. The discussion that follows describes each of these components and provides an estimate of each component's share of total capital costs.

2.11. Coal Handling Equipment

Coal handling equipment provides for unloading, conveying, preparing and storing coal delivered to a coal power plant. The coal handling equipment used for an IGCC is largely the same as that used at PC power plants. Similar to PC plants, the primary preparation of the fuel is crushing or pulverizing prior to feeding it into the gasification system. Some gasification technologies use dry fed coal through lock hoppers, while others are fed fuel in coal-water slurry.[80] Coal handling equipment accounts for about 12 percent of the capital cost of an IGCC.[81]

2.12. Gasifier

Gasification is the partial oxidation of a solid or liquid fuel feedstock to produce a gaseous product (syngas) made up of predominantly H_2 and CO.[82] Gasifiers convert carbon-based feedstocks (such as coal, petroleum coke, heavy oils or biomass) into gaseous products at high temperature (2,000-3,000°F) and elevated pressure (400-1,000 psi) in the presence of oxygen and steam. Gasification occurs in a reducing (oxygen-starved) environment where insufficient oxygen is supplied for complete combustion of the fuel feedstock. Partial oxidation of the feedstock creates heat and a series of chemical reactions produce syngas.[83]

IGCC systems can incorporate any one of a number of gasifier designs, but all are based on one of three generic configurations:[84]

> *Moving-bed reactors (also called fixed-bed)*: In moving-bed reactors large particles of coal move slowly down through the gasifier while reacting with gases

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[80] SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 7.

[81] EPRI/NETL, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, Dec. 2002 (7-10 Cost breakdown based on cost estimates in Case 9A—IGCC without CO_2 removal, Appendix A, p. A-30).

[82] Syngas also contains some carbon dioxide (CO_2), moisture (H_2O), hydrogen sulfide (H_2S) and carbonyl sulfide (COS) as well as small amounts of methane (CH_4), ammonia (NH_3), hydrogen chloride (HCI) and various trace components from the feedstock. See SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 7..

[83] See EPRI/NETL, p. 7-11—7-15. See also SFA Pacific, Inc., p. 7. See also NETL, Major Environmental Aspects, Appendix 1A.

[84] NETL, Major Environmental Aspects, p. 1-7.

moving up through it. Several different "reaction zones" are created that accomplish the gasification process. The Lurgi dry-ash and the British Gas/Lurgi (BGL) gasifier employ this technology and are currently operating at several facilities.[85]

Fluidized-Bed Reactors: Fludized-bed reactors efficiently mix feed coal particles with coal particles already undergoing gasification in the reactor vessel. Coal is supplied through the side of the reactor, and oxidant and steam are supplied near the bottom. Commercial suppliers include the High Temperature Winkler (HTW) and KRW designs. Few of these systems are currently in operation.[86]

Entrained-flow Reactors: Entrained-flow systems react fine coal particles with steam and oxygen and operate at high temperatures. These systems have the ability to gasify all coals regardless of rank. Different systems may use different coal feed systems (dry or water slurry) and heat recovery systems. Nearly all commercial IGCC systems in operation or under construction are based on entrained-flow gasifiers. Commercial entrained-flow gasifier systems are available from GE Energy Gasification Technologies ("GE Energy"),[87] ConocoPhillips,[88] Shell, Prenflo, and Noell.[89]

The commercial gasification processes believed most suited for near-term IGCC applications using coal or petroleum coke feedstocks are the GE Energy,[90] ConocoPhillips, and Shell entrained-flow gasifiers.[91] Each of these technologies is currently deployed at an operating commercial IGCC facility.

In addition to incorporating an entrained-flow process, each of these gasification processes, and all of the gasification processes demonstrated to date for commercial IGCC use, are oxygen-blown systems.[92] Oxygen-blown gasification requires supplying a stream of compressed oxygen to the gasification reactor. The stream of oxygen is produced by a cryogenic oxygen plant commonly called an air separation unit (ASU). Cryogenic oxygen production is an established commercial process that is used extensively worldwide.[93]

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[85] Id., p. 1-8.
[86] Id., p. 1-10.
[87] GE Energy Gasification Technologies acquired the ChevronTexaco process July 1, 2004.
[88] ConocoPhillips acquired the patents and intellectual property rights to Global Energy's proprietary E-GAS gasification process in 2003. This technology was originally developed by Dow Chemical Company and later transferred to Destec, a partially held subsidiary of Dow Chemical. In 1997, Destec was purchased by Houston-based NGC Corporation, which became Dynegy, Inc. in 1998. In December 1999, Global Energy Inc. purchased the gasification technology from Dynegy and in 2003 ConocoPhillips purchased the technology from Global Energy (see DOE, Clean Coal Technology Topical Report Number 20, "The Wabash River Repowering Project—an Update," Sept. 2000, p. 4).
[89] NETL, Major Environmental Aspects, p. 1-10--1-11.
[90] See FN 65.
[91] SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 8.
[92] Id., p. 7.
[93] Id.

The compression of oxygen for oxygen-blown gasifiers requires costly compressors and utilizes substantial power. The auxiliary power requirements of the ASU account for the largest parasitic load on an IGCC facility utilizing an oxygen-blown gasifier.[94] One way to help reduce this parasitic load is to integrate the combustion turbine (CT) and ASU by extracting a portion of the air from the compressor of the CT to feed the ASU. However, because of reliability problems associated with 100 percent integration found at several demonstration facilities, current industry thinking in the U.S. is that about 50 percent integration is the maximum that should be used.[95]

The alternative to oxygen-blown gasification is air-blown gasification, which eliminates the need for the ASU. However, air-blown gasification results in the dilution of the syngas by nitrogen in the air, creating a syngas with a lower volumetric heating value.[96] As a result, air-blown gasification requires larger gasifiers, has lower fuel energy conversion efficiencies and creates additional technical challenges for the gas clean up and combustion turbine operation. Air-blown gasification also is less suited for cost-effective separation and capture of CO_2 emissions. For these reasons, the next generation of IGCC facilities are expected to be based on entrained-flow, oxygen-blown (rather than air-blown) gasification technologies.[97]

An entrained-flow, oxygen-blown gasification island, including the ASU and syngas cooling systems discussed below accounts for about 30 percent of the cost of a new IGCC facility.[98]

2.13. Syngas Cooling

Coal gasification systems operate at high temperatures and produce raw, hot syngas. Typically, the syngas is cooled from around 2,000°F to below 1,000°F (and the heat recovered). Cooling is accomplished using a waste heat boiler, or a direct quench process that injects either water or cool, recycled syngas into the raw syngas (a version of the GE Energy technology uses the quench method while Shell and ConcoPhillips have waste heat recovery systems). When a waste heat boiler is used, steam produced in the boiler is typically routed to the heat recovery steam generator (HRSG) to augment steam turbine power generation.[99]

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[94] Id., p. 14.
[95] Id.
[96] Id., p. 9.
[97] Id.
[98] EPRI/NETL, Appendix A, p. A-30.
[99] Id., p. 7-15.

2.14. Syngas Clean-up

Syngas clean-up generally entails removing particulate matter, sulfur and nitrogen compounds from the syngas before it is directed to the CT.[100] Particulate removal is accomplished using either ceramic or metallic filters located upstream of the heat recovery device, or by "warm gas" water scrubbers located downstream of the cooling devices.[101] The particulate material, including char and fly ash, is then typically recycled back to the gasifier. When filters are used, they are cleaned by periodically back pulsing them with fuel gas to remove trapped material.[102]

Next the syngas is treated in "cold-gas" clean up processes to remove most of the H_2S, carbonyl sulfide (COS) and nitrogen compounds. The gas treating processes employed to remove these compounds are well established in the natural gas production and petroleum refining industries.[103] The primary processes (called acid gas removal (AGR) processes) are chemical solvent-based processes (using aqueous solutions of amines such as methyl diethanolamine (MDEA)) and physical solvent-based processes (such as Selexol, which uses dimethyl ethers of polyethylene glycol, or Rectisol, which uses refrigerated methanol).[104] The Selexol and Rectisol processes are better adapted to remove CO_2 in the future. Sulfur recovery processes recover sulfur either as sulfuric acid or as elemental sulfur. The most common removal system for sulfur recovery is the Claus process, which produces elemental sulfur from the H_2S in the syngas that can be sold commercially.[105]

The cost of these gas clean-up systems and associated piping accounts for about 7 percent of total plant costs.[106]

2.15. Combined Cycle Power Block

After clean-up, the syngas is sent to the combined cycle power block. In a combined cycle system, the first generation cycle involves the combustion of the primary fuel--which can be oil, natural gas, or, in this case syngas--in a combustion turbine (CT). The CT powers an electric generator, may provide compressed air to the air separation unit or gasifier, and produces hot exhaust gases that are captured and directed to a heat recovery steam generator (HRSG) to produce steam for a steam turbine to complete the combined power cycle.[107]

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[100] Additional clean-up processes could also be employed for mercury removal and carbon separation to significantly reduce mercury and carbon dioxide emissions. See Section 2.31 below.
[101] NETL, Major Environmental Aspects, p. 1-12.
[102] Id.
[103] SFA Pacific, Inc., p. 10.
[104] Id.
[105] NETL, Major Environmental Aspects, p. 1-12.
[106] EPRI/NETL, Appendix A, p. A-30.
[107] NETL, Major Environmental Aspects, p. 1-13.

Syngas fuel is essentially interchangeable with natural gas as fuel for modern combustion turbines (the Wabash IGCC plant in Indiana currently switches between syngas and natural gas), but there are some process differences when syngas is used. The primary difference is that the volumetric heating value of cleaned syngas is about 20-30 percent that of natural gas, so a much larger volume of fuel is required with syngas firing to provide the necessary energy input to the CT.[108] This large volume requires different piping, control valves, and burners and results in a larger total mass flow through the CT. As a result, the power output of the CT increases. For example, the GE Frame 7FA+e CT has an output rating of 172 MW on natural gas, but an output rating of 197 MW on syngas.[109]

The combined cycle power block, including the CT, HRSG and steam turbine generator accounts for about 33 percent of the cost of an IGCC.

2.16. Balance of IGCC Plant

Other components of an IGCC facility include cooling water systems, ash and spent sorbent handling systems, electric plant accessories, instrumentation and control systems, on-site buildings and structures and site improvements.[110] Together these typically account for about 18 percent of plant costs. Table 2.2 summarizes the major components of an IGCC power plant and their approximate share of construction cost including contingencies.[111]

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[108] SFA Pacific, Inc., p. 12.
[109] Id.
[110] EPRI/NETL, Updated Cost and Performance Estimates, p. 4-72.
[111] Estimated share of plant costs based on a conceptual plant design and may be substantially different depending on the processes used, location of the facility and other plant or process-specific factors. In addition, IGCC power plants may include additional processes for removing mercury, separating and capturing CO_2, or producing various chemical outputs that are not included in the estimated breakdown in Table 1.2.

Table 2.2. Major IGCC Components and Approximate Share of Construction Costs

Process Description	Function	Share of Construction Cost
Coal Handling Equipment	Receive, prepare and feed coal feedstock into gasifier	12%
Gasifier, ASU and Syngas Cooling	Gasify coal into syngas; produce pure oxygen stream for gasification process, and cool raw syngas	30%
Gas Clean-up and Piping	Remove particulates, and acid gases from syngas	7%
Combined-Cycle Power Block	Generate electricity with syngas using a CT and steam turbine cycle	33%
Remaining Components and Control Systems	Cooling systems, spent ash and sorbent handling, controls and structures	18%
		100%

2.2. Operating IGCC Facilities used for Commercial Electricity Production

Five IGCC facilities designed for commercial electricity production are described below, including two in the U.S., two in Europe, and one in Japan. Four use coal and/or petroleum coke feedstocks, and one uses asphalt feedstock. Table 2.3 summarizes operating information for each facility.

2.21. Wabash Power Station, Terre Haute, Indiana

The Wabash Power Station IGCC plant began operation in 1996 and has been operating for more then eight years. The project was initiated in 1991 as a DOE Clean Coal Technology (CCT) program demonstration project. Construction began in July 1993 and was completed in November 1995. The project repowered an existing coal power plant by adding a gasification island and CT, and by refurbishing a steam turbine at the facility to extend its life and enable it to withstand the increased pressure and steam flow associated with combined cycle operation.[112]

The project was undertaken as a joint venture between Destec Energy Inc. of Houston (owner of the E-gas gasification process prior to ConocoPhillips) and PSI Energy, an investor owned utility in Indiana (now Cinergy). The plant is a 262 MW (net) facility utilizing the ConocoPhillips gasification process based on an entrained-flow, oxygen-blown, two-stage gasifier that uses natural gas for start-up. The facility was designed for and utilized bituminous coal for its first three years of operation, but later switched to petroleum coke for economic reasons. The total plant investment was $438 million ($1,680/kW in mid-2000 dollars), half of which was contributed by DOE.[113]

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[112] NETL, Major Environmental Aspects, Appendix 1B-9.
[113] DOE, Clean Coal Technology Topical Report Number 20, p. 12.

The plant operating performance has generally improved over time as systems have been modified and optimized. From 1998-1999, during the plant's demonstration period, availability (including both the gasification island and the power train) was 62.4 percent, which improved to 73.3 in 2000, 72.5 percent in 2001, 78.7 percent 2002, and 82.4 percent in 2003.[114]

2.22. Polk Power Station, Polk County, Florida

The Polk Power Station is an IGCC plant built by Tampa Electric Company based on the entrained-flow, oxygen-blown GE Energy gasification technology. Like Wabash, it was built as part of the DOE CCT program, with a 50 percent cost share from DOE. Unlike Wabash, the Polk Station was built on a greenfield site, rather than being a repowering of an existing coal plant. Construction on the facility began in October 1994 and operation began in September1996.[115]

Polk Power Station is a 250 MW (net) facility that has utilized a variety of bituminous coals as well as a petroleum coke/coal mixture. The total direct cost of the project in 2001 dollars was $448 million ($1,790/kW). Tampa Electric estimates that incorporating the lessons learned and changes made at the plant, a plant of the same design could be built in 2001 dollars for $412 million ($1,650/kW).[116]

Like Wabash, the Polk Stations operating performance has been reliable. The availability of the gasification island steadily improved from just over 60 percent in 1998 to 80 percent in 2000. In 2001, two unplanned outages decreased the availability to 70 percent, but it increased back to 74 percent in 2002. Since 1998, the power block of the facility has had an availability of about 90 percent, because the turbines can be run on either syngas from the gasifier or distillate fuel.[117]

2.23. Willem Alexander IGCC Plant, Buggenum, The Netherlands

The Willem Alexander plant in Buggenum was commissioned in 1994, making it one of the first commercial IGCC plants in the world. The project was built and operated by Demkolec BV and is today owned by NUON.

The plant is a 253 MW (net) IGCC utilizing a Shell entrained-flow, oxygen-blown, dry feed gasifier. The plant, which was built to utilize a number of different imported coals, differs significantly from its counterpart in the U.S. in that it includes full integration of the gas turbine and ASU. This integration means that the turbine supplies all of the air to the ASU, which helps increase efficiency (the plant design efficiency is 43 percent LHV,

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[114] Keeler, Clifton, *"Operating Experience at the Wabash River Repowering Project,"* Presentation at the 2003 Gasification Technologies Conference, San Francisco, CA, Oct. 2003.
[115] NETL, "Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report," Aug. 2002, p. I-1.
[116] Id., p. 4-1—4-2.
[117] Id., p. ES-5.

which is proven in practice), but makes it more complex and difficult to start, which affected its initial availability. After encountering operating problems mainly related to turbines in its initial years, design changes were made in 1997 that significantly improved plant performance. The plant operated at 84 percent availability in 2002 and 87 percent in 2003. The year-to-date May 2004 availability is over 95%

The plant served as an IGCC demonstration plant during initial years of operation and had been used to test different operating conditions and various feedstock with commercial scale. 14 types of coal, including 6 types of blend coal (ash content > 16%wt.; sulfur > 1%wt), have been successfully gasified. Because of the dry feed system, the plant consumes less water than slurry based systems and has no water discharge.

After the change of ownership to NUON, the plant management decided to operate the plant for commercial purpose and conducted programs aiming at achieving stable operation. As a result, the availability of the gasification system and thus the number of operating hours on syngas production has been increased significantly since 2001. The lifetime of the gasifier burners has proven to be well over 20,000 operating hours; and the lifetime of the filter candles in the HPHT filter has exceeded 25,000 operating hours. The thin refractory lining at the inner side of the gasifier membrane wall has not been replaced nor repaired since the plant started operations in 1994.

2.24. Puertollano IGCC Plant, Puertollano, Spain

The Puertollano plant is a 298 MW (net) IGCC owned and operated by Elcogas, a consortium of eight major European utilities and three technology suppliers. The plant utilizes a Prenflo gasifier, which is an entrained-flow, oxygen-blown system with dry fuel feeding.[118]

Similar to the Willem Alexander plant, the Puertollano plant has full integration of the gas turbine and ASU, which enables it to operate at a high efficiency (45 percent LHV basis), but has reduced the operating performance of the facility. In 2000 and 2001, the plant availability was around 60 percent, substantially below what is generally required of a commercial coal generating facility in the U.S.[119]

2.25. Negishi IGCC Plant, Negishi, Yokohama Japan

The Negishi IGCC facility is owned by Nippon Petroleum Refining Co. and started commercial operation in June 2003. At 342 MW (net) it is the largest IGCC plant currently in operation. The facility is based on a GE Energy Direct Quench Type gasifier and is designed to utilize a variety of feedstocks. As of August 15, 2003, the facility had 1,128 hours of commercial operation with a 99.3 percent power block availability and

[118] NETL, Major Environmental Aspects, p. 1B-12.
[119] Id.

96.1 percent gasification syngas availability. The facility employs an advanced sulfur recovery system that removes 99.8 percent of sulfur from the syngas.[120]

Table 2.3. Summary Statistics for Commercial Electricity Generation IGCC Plants

	Wabash Power Station	Polk Power Station	Willem Alexander	Puertollano	Negishi
Owner	Cinergy/ ConocoPhillips	Tampa Electric	NUON	ELCOGAS	Nippon Refining
Location	Indiana, US	Florida, US	Netherlands	Spain	Japan
Capacity (MW net)	262	250	253	298	342
Gasifier	ConocoPhillips	GE Energy	Shell	Prenflo	GE Energy
Gas Turbine	GE MS 7001FA	GE MS 7001FA	Siemens V 94.2	Siemens V 94.2	MHI 701F
Efficiency (% HHV)	39.7	37.5	41.4	41.5	Unk.
Heat rate (Btu/KWh HHV)	8,600	9,100	8,240	8,230	Unk.
Fuel Feedstock	Bit. coal/ pet coke	Bit. coal/ pet coke	Bit. coal	Bit. coal/ pet coke	Asphalt
Particulate control	Candle filter	Water scrubber	Candle filter	Candle filter	Unk.
Acid gas clean-up	MDEA scrubber	MDEA scrubber	Sulfinol M	MDEA scrubber	Shell Adip
Sulfur recovery	Claus plant	H_2SO_4 plant	Claus plant	Claus plant	Lurgi Oxyclaus
Sulfur by-product	Sulfur	Sulfuric acid	Sulfur	Sulfur	Unk.
Sulfur Recovery (%)	99% design	98% design	99% design	99% design	99.8%
NOx control	Steam dil.	Nitrogen & steam dil.	Syngas sat & nitrogen dil.	Syngas sat & nitrogen dil.	Unk.

[120] Ono, Takuya, "NPRC Negishi IGCC Startup and Operation," presented at Gasification Technologies 2003, Oct. 12-15, 2003, San Francisco, CA. 2003, San Francisco, CA.

3.0. IGCC DEPLOYMENT

With 2004 natural gas prices at levels two to three times above historic averages, the focus of many power plant developers has shifted to coal technologies, which is stimulating interest in IGCC. How much of the new capacity built in the next decade is IGCC will depend on whether IGCC is an economically and financially attractive alternative as capacity decisions are made. For reasons discussed below, a window of opportunity exists for IGCC investments, but they will not materialize unless the technology is viewed as commercially competitive and proven, which is unlikely to happen in the near-term without federal and state policies that stimulate access to low cost capital and competitively priced electricity output.

3.1. Support for IGCC

One reason a window of opportunity exists for IGCC is that a diverse group of interests are generally supportive of finding policy approaches to commercialize the technology in this decade. Often for different reasons, the following groups have an interest in IGCC deployment:

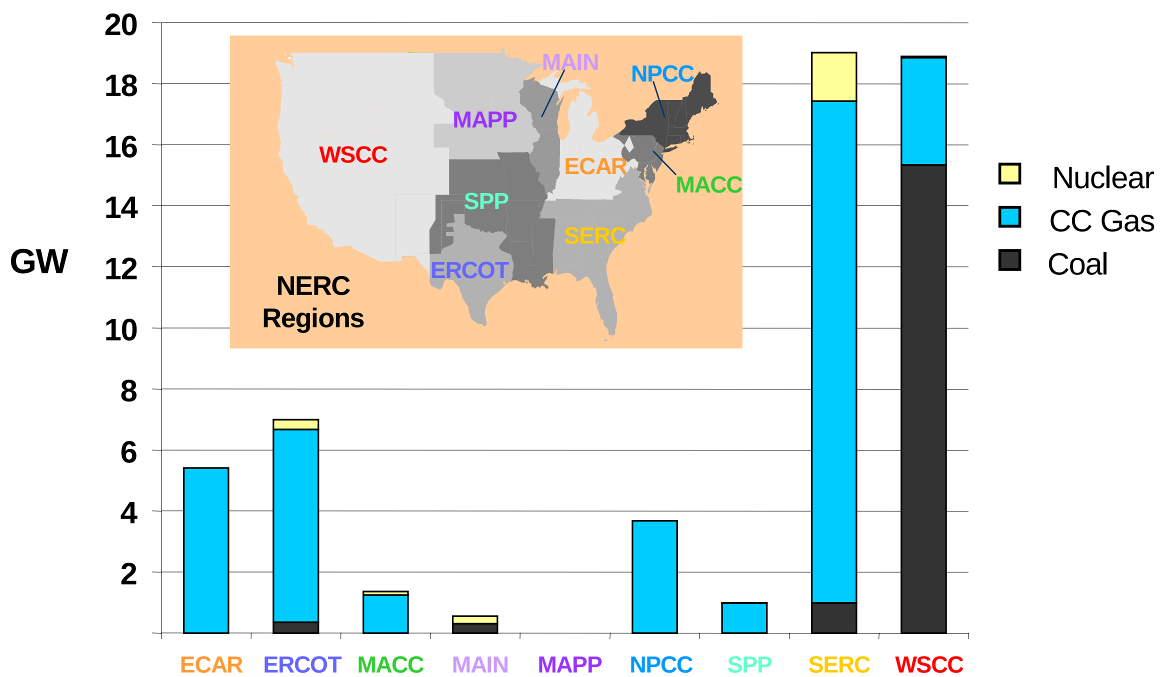
- Electric utilities — have a growing need to develop new base load capacity and are interested in technologies that enable the use of coal in a carbon constrained, high natural gas price environment;
- Utility regulators — are interested in options for new capacity, including advanced coal technologies that reduce costs to ratepayers;
- Coal producers — interested in enhancing market share and reversing the trend away from new coal plants (in part due to environmental concerns) that began in the late 1980s;
- DOE — sees energy supply and national security benefits to using U.S. coal reserves and has invested billions of dollars in the Clean Coal Technology program, which has been a leading force in the development and demonstration of IGCC technology;
- EPA — is supportive of sustainable coal utilization and deployment of technologies that reduce coal plant emissions and water consumption;
- Environmentalists — see IGCC as a potential foundation technology for moving toward CO_2 capture and sequestration to address climate change concerns;
- Industrial natural gas users—are interested in ways to reduce demand pressure on natural gas prices by reducing consumption by electric generators;
- NGCC owners — see IGCC as providing an opportunity to restore value to distressed NGCC assets by refueling to syngas.

This broad base of potentially supportive groups can prove beneficial for developers seeking to build IGCC (particularly if environmental groups and utility regulators have a favorable view of the technology) and form the basis for adoption of federal initiatives to support a 3Party Covenant or other incentive program to promote near-term deployment.

3.2. Need for Base Load Capacity

Another factor creating opportunities for IGCC investment is the growing need for baseload capacity additions over the next decade. During the period 2005 to 2015, the Energy Information Administration (EIA) projects the addition of 57 giga-watts of new coal, nuclear and combined cycle gas generating capacity to serve electricity demand, which is equivalent to about 100 new 550 MW power plants (average of 10 per year). Figure 3-1 illustrates EIA's projected geographic dispersion of this capacity by North American Electric Reliability Council (NERC) region and by fuel type. Illustrated in Figure 3-1 is that two-thirds of the capacity is projected to be added in the Southeast and Western U.S. and that two-thirds of the new capacity across the country is projected to be combined cycle natural gas generation. The EIA forecast projects 17 giga-watts of new coal capacity (or about 30 new 550 MW coal plants) over the period, 90% of which are projected to be built in western states.

Figure 3-1. EIA 2005-2015 Coal, Nuclear, and NGCC Capacity Additions



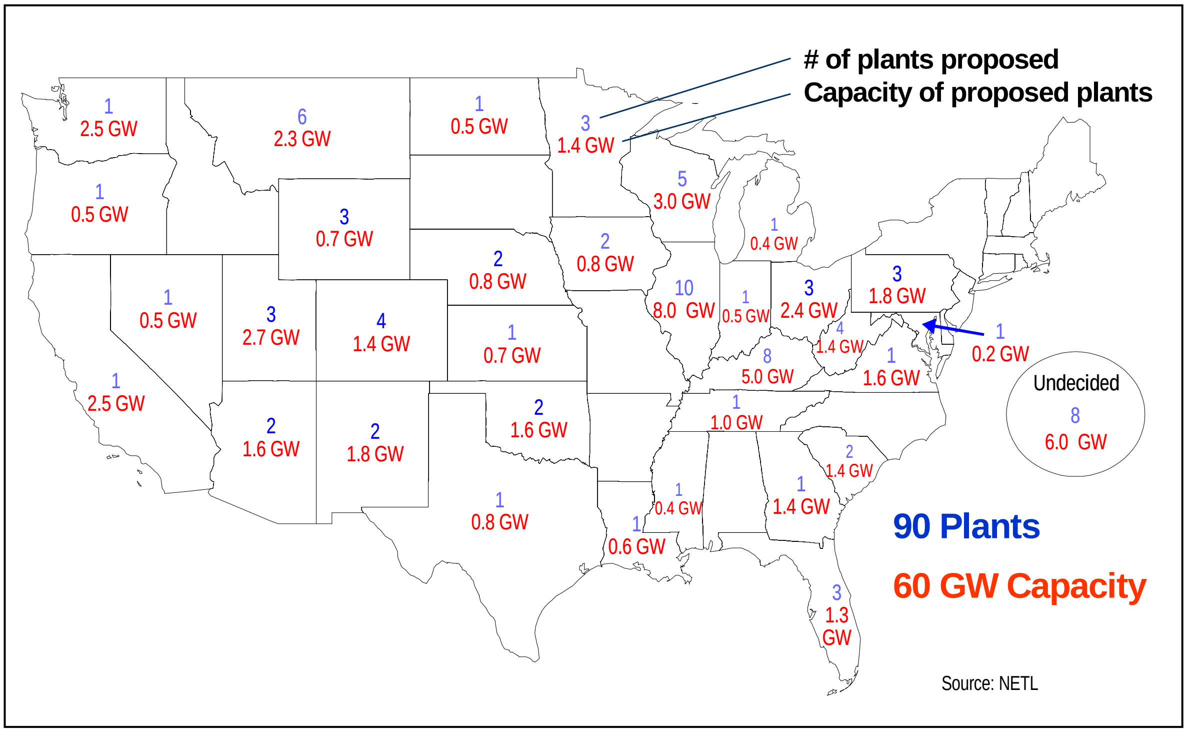
Source: EIA, Annual Energy Outlook 2004, Supplemental Regional Data, Table 75.

Considering the current trend away from natural gas and towards interest in new coal generation (see Section 4.12 below), it is likely that this forecast overstates the role of natural gas combined cycle and understates the role of coal for new capacity needs over the next ten years. Nonetheless, even 17 giga-watts of new coal capacity represents a significant increase and opportunity for IGCC deployment. If IGCC investments are viewed as commercially competitive with PC technology, they can account for a significant share of this new capacity and establish the commercial viability of IGCC technology in the near term. If IGCC technology does not achieve significant market share over the next 10 years, the technology will have missed an important chance for near-term deployment and its impressive environmental benefits will be pushed well off into the future.

3.3. Coal Power Development

A new appreciation for the volatility and unpredictability of natural gas prices began to emerge in 2000 and has accelerated interest in the development of new coal-fired generating capacity. According to the Department of Energy, as of February 2004, 94 new coal plants had been proposed in the U.S., representing 61 giga-watts of new coal capacity and $63 billion of potential investment. Figure 3-2 illustrates the number of proposed plants and total giga-watts of proposed capacity by state. The amount of new coal capacity currently being proposed is three times the total new coal capacity projected to be added by EIA by 2015. While it is unclear how much of this proposed new capacity

Figure 3-2. Proposed New Coal Power Plants as of February 2004



will actually be built, the data indicate a strong interest in coal power plants and suggest that if the economics and risks of IGCC are viewed as acceptable, and attractive financing is available, there will be commercial interest in IGCC deployment.

This conclusion is supported by the fact that several companies have announced plans to develop IGCC projects (although it is unlikely any of the projects will actually be built without 3Party Covenant or other government financial assistance). Excelsior Energy is working to develop a 450 MW IGCC plant in Minnesota (Mesaba Energy Project), Global Energy is working to develop a 540 MW IGCC plant in Kentucky (Kentucky Pioneer), and Clean Coal Power Resources has announced its intention to build a 2,400 MW facility in Illinois.

3.4. NGCC Re-Fueling Opportunity

A major opportunity for IGCC deployment has arisen from the impact of high natural gas prices on existing natural gas combined cycle facilities. The high prices, combined with soft electricity markets, have made many natural gas combined cycle generating plants uneconomic. Many of these facilities are now being sold, written-off, mothballed, or repossessed by banks.

For example, in May, 2004 Duke Energy announced the sale of 5,325 MW of merchant natural gas generating capacity for $475 million, or $89 per kilowatt, which is less than one-fifth of original cost. In a related matter, Duke Energy announced in January, 2004 that it was taking a $3 billion write off from 2003 earnings, in large part because of the decline in value of its natural gas generation fleet in the Southeast U.S.[121] Furthermore, a study by SAIC for DOE/NETL indicates that as of April 2004 as much as 33,000 MW of distressed merchant gas capacity was for sale.[122] The study also indicates that a number of natural gas plants have been mothballed (including a 1,100 MW NGCC plant in Hays County, Texas) and that as many as 50 GE7FA natural gas turbines are currently sitting in warehouses because the projects for which they were purchased have not gone forward.[123] Many natural gas-fired power plants are also being repossessed by lending institutions, including Citibank (4,150 MW), Societe Generale (5,550 MW) and BnP Paribas (3,400 MW).[124]

The devaluation and market availability of underutilized natural gas generation assets presents an important opportunity for early and cost-effective coal gasification refueling. The combined cycle power block associated with a NGCC power plant is essentially the same as the combined cycle power block needed for an IGCC facility. To convert an existing natural gas turbine to use synthesis gas from a coal gasifier is estimated to cost

[121] See http://www.dukeenergy.com/news/releases/2004/jan/2004010701.asp
[122] NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.
[123] Id.
[124] Id.

only $5 million for a typical 350 MW plant, or roughly $15/kW.[125] This cost could be more than made up for by large savings associated with using a distressed NGCC facility to provide the combined cycle power block for the IGCC plant. For example, if a distressed NGCC facility is used for an IGCC refueling at 75% of its original cost ($375/kW, assuming $500/kW as the original cost) then even with the retrofit cost there is a savings of over $100/kW versus building a new power block.

Furthermore, refueling to IGCC means taking a depressed asset facing large-scale write-offs that is operating at only a fraction of its capacity and repositioning it to operate as an economical base load coal facility that operates at a high (80-90%) capacity factor. If this type of refueling were done under the 3Party Covenant, the owner also receives a regulated 11.5 percent after-tax return for the new value of the repositioned asset. The refueling potential is creating a new category of enthusiastic, potential IGCC developers. With 3Party Covenant financing, the cost of energy from the resulting plant is well below the cost of energy from a new PC plant (see Section 5.6 below).

Not all NGCC power plants are suited for IGCC refueling. SAIC's preliminary analysis for DOE estimates that as much as 12,000 MW (enough for about 20 550 MW IGCC facilities) of existing NGCC facilities may be suitable for IGCC conversion. This estimate is based on plants larger than 250 MW that appear to have coal available by railroad.[126]

3.5. IGCC Deployment Hurdles

Despite the potential benefits and commercial interest in IGCC, investments to design and build commercial IGCC power plants in the U.S. have not materialized due to financing, cost, and risk concerns. A 2004 survey by DOE indicates that the three leading risk factors perceived by industry to be associated with IGCC investments are high capital costs, excessive down time, and difficulty with financing.[127]

Most estimates suggest that the capital costs associated with a new IGCC power plant are about 20 percent higher than the cost of a new PC plant, and IGCC costs are less certain. Furthermore, unlike pulverized coal boilers, IGCC technology is not perceived to have sufficient experience and to have operating risks that are not clearly understood. The operating performance of IGCC has only been demonstrated at a handful of facilities, which have reached 80 percent availabilities, but not the 90 percent and higher availability preferred for modern commercial base load coal generation.[128]

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[125] Id.
[126] Id.
[127] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.
[128] As discussed in Section 2.4 below, the incorporation of redundant gasification capacity should enable IGCC facilities to readily achieve this level of availability.

The financing hurdle is compounded by the deteriorated creditworthiness of the electric utility industry today. A November 2003 report by Standards and Poors stated that:

> "the average credit rating for the electric utility sector is now firmly in the 'BBB' category, down from the 'A' category three years ago. Furthermore, prospects for credit quality remain challenging, as indicated by rating outlooks, 40 percent of which are negative."[129]

Lower credit ratings make if more difficult and costly for power developers to raise money for large, capital-intensive coal projects (whether PC or IGCC) costing in the range of a billion dollars. Companies under credit rating pressure are less likely to take on new recourse debt, or support power purchase agreements with long-term capacity commitments. Add the uncertainty of a relatively new generating technology such as IGCC, and financing becomes a serious constraint to deployment. Financing difficulties are an important explanation of why so few new PC plants have been constructed in the past 12 years in the face of an NGCC boom of 175,000 MW and why no commercial IGCC plants have gone forward.

A 2003 decision by the Wisconsin Public Service Commission to approve a WEPCO proposal to build two PC power plants, but reject the company's proposed IGCC facility, illustrates a fundamental chicken and egg problem facing IGCC technology. In Wisconsin, the commission determined that "IGCC technology, while promising, is still expensive and requires more maturation. For these reasons, the application to construct the IGCC unit is denied."[130] In order for IGCC technology to become commercially mature and economic it needs to be deployed, but in order for it to be deployed it needs to be perceived as mature and economic. Helping to resolve this dilemma through commercial deployment of a small fleet of IGCC power plants is the objective of the 3Party Covenant financing program. As described below, the 3Party Covenant addresses the primary IGCC risk factors industry experts have identified as inhibiting commercial investment.

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[129] Ronald M Baron, *"U.S. Power and Energy Credit Outlook Not Promising; Few Bright Spots,"* Standard & Poors, Nov. 11, 2003.

[130] Wisconsin Electric Power Co., 228 PUR4th 444, 459, 2003 WL 22663829 (Wisc. P.S.C. Nov. 10, 2003).

4.0. 3PARTY COVENANT FINANCING AND REGULATORY PROGRAM

The 3Party Covenant is a financing and regulatory program that aims to address the hurdles inhibiting IGCC deployment. It is designed to provide developers of IGCC power plants access to capital at lower cost and in a way that tolerates technology risk. The program significantly reduces cost of capital to make IGCC economically competitive and minimizes the budget expenditure required of the federal government. The program is designed to facilitate development of an initial fleet of commercial IGCC plants this decade to establish the commercial viability of the technology and promote commercial optimization to reduce costs.

4.1. Key Elements of 3Party Covenant

The 3Party Covenant is a financial and regulatory arrangement among a federal agency, a state PUC, and an equity investor to finance the development of an IGCC power plant. The three key elements are as follows:

> *Federal Loan Guarantee:* The program for implementing the 3Party Covenant is established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee provide for an 80/20 debt to equity financing structure and require that a proposed project obtain from a state PUC an assured revenue stream to cover return of capital, cost of capital, and operating costs. The terms also require the project to have appropriate construction guarantees, from the EPC firm hired to design and build the plant, and to meet stringent environmental performance specifications. The terms would also enable the project to have available an additional draw on the federally guaranteed debt ("Line of Credit") of up to 15 percent of project Overnight Capital Costs (to be matched with a 20 percent equity contribution when drawn).
>
> *State PUC Approval Process:* States interested in participating in the program voluntarily opt-in by adopting utility regulatory provisions for state PUC review and approval of IGCC project costs, which in some states requires legislative action to create appropriate enabling authority. Specifically, a state PUC (or other utility ratemaking body in the case of municipal utility or rural electric cooperative), acting under state enabling authority, agrees to assure dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation, maintenance, fuel costs, and taxes). (Depending on the ownership structure and sales profile (i.e., retail sales versus wholesale sales) of the IGCC project, the Federal Energy Regulatory Commission (FERC) may take on some of the role otherwise assigned to the state PUC.) The state PUC provides this revenue certainty through utility rates in states with traditional regulation of retail electricity sales, or through non-bypassable wires charges and fixed capacity charges in states with competitive retail

electricity sales, by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery of approved costs, including cost of capital. The certification by the state PUC occurs upfront when the decision to proceed with the project was being made, and the prudence review by the state PUC and cost recovery occurs on an ongoing basis starting during construction, which reduces the construction risks borne by the developer, avoids accrual of construction financing expenses, and protects ratepayers.

Equity Investor: The equity investor under the 3Party Covenant is either an electric utility (or municipal utility or rural electric cooperative) or an independent power producer that secures a long-term power contract with a utility (or a contract that has a comparable credit rating). The investor contributes equity for 20 percent of the Total Plant Investment and negotiates performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return is determined and approved by the state PUC before construction begins.

The 3Party Covenant program provides a mechanism for reducing investor risk and the cost of IGCC power to stimulate project investments this decade. As demonstrated in Section 5.5 below, the approach significantly reduces the cost of IGCC power, making it cost competitive with PC and natural gas combined cycle generation.

4.2. Roles and Perspectives of Three Parties

Under the 3Party Covenant, the federal government provides credit, the state PUC provides an assured revenue stream to protect the federal credit, and the developer provides equity and initiative to build the IGCC project. In return, the federal government stimulates IGCC deployment to support energy, national security, and environmental policy objectives at low federal cost, the state receives competitively priced power, economic development benefits (investment and jobs), and environmental improvement, and the equity investor receives access to nonrecourse, low-cost debt, assured equity returns, and an economic base-load power plant. The roles of each party and their potential motivations for participating in the program are discussed in more detail below.

4.21. Federal Government

Authority for the federal loan guarantee is established through federal legislation authorizing loan guarantees to finance IGCC projects. The guarantee pledges the full faith and credit of the United States Government, thereby receiving a “AAA” credit rating on project debt financing. The legislation establishes a government loan guarantee administrator (presumably DOE) that is responsible for ensuring that construction, operating, and market projections of a proposed IGCC project demonstrate economic feasibility and the ability to meet debt service obligations. The availability of a federal loan guarantee provides a powerful incentive from the federal government that will encourage state PUC and equity investor participation by lowering financing costs and sharing risks with the federal government.

The administrator also sets the financing terms and conditions of a federal loan guarantee for the debt financing. These terms include allowance of a favorable 80/20 debt to equity structure and performance requirements for qualification. The high debt to equity ratio is critical because it accounts for the majority of the economic savings provided by the program (see Section 5.5 below). It is reasonable for the federal government to guarantee up to 80% of the Total Plant Investment because the federal government is protected from risk of loan default by the state PUC regulatory determinations required by the 3Party Covenant.

The most important condition for qualification for a 3Party Covenant loan guarantee is state PUC certification and approval procedures for the project, which will include issuance of a final order that ensures timely recovery of approved project costs, including cost of capital. These state PUC procedures reduce the risk borne by the federal loan guarantee and include: (1) certification before construction begins that an IGCC project meets federal and state requirements; (2) periodic review and approval of the prudence of each portion of the project as construction proceeds; and (3) cost pass-through providing strong assurance of timely recovery, during construction, of the approved return on capital for each approved portion and, once the plant is completed, for recovery of approved capital investment, return on capital, and operating costs.

In return for establishing the federal loan guarantee program, the federal government receives the energy, national security, economic and environmental policy benefits of IGCC deployment and commercialization at low risk and low budget cost.

4.22. States

The 3Party Covenant is distinguished from other federal financing programs because a principal party is a state PUC or the oversight board of a municipal utility or rural electric cooperative, which effectively controls the revenue stream needed to service the federally guaranteed debt. The state PUC, operating under state enabling law, reviews and approves the IGCC plant proposal upfront, determines the need for power, establishes the mechanism for allocation of project risks and recovery of approved costs, conducts ongoing prudence review during construction and operation, and determines the amount and timing of project revenues.

Unlike the Public Utility Regulatory Policy Act (PURPA), where federal law required utilities to purchase power at avoided cost from qualifying facilities, the 3Party Covenant program is entirely voluntary. The federal government establishes terms and conditions for receiving the federal loan guarantee, but there is no requirement for any company or state to participate in the program.

The 3Party Covenant requires states that choose to participate to establish a state PUC review and approval process that provides for cost recovery and assured revenue to cover debt service and other capital and operating costs (approved by the state PUC) before financial commitments for a federal loan guarantee become effective. Traditionally, state PUC prudence reviews occur after a project is completed, when the opportunity to address problems are limited. The 3Party Covenant requires upfront certification review and ongoing prudence reviews. Once the state PUC assures revenues to service the federally guaranteed loan, the amount of the loan that must be scored as a federal budget expense should be significantly lower, because risk of default is significantly reduced.

The legal authority of state PUCs to participate in a 3Party Covenant is determined by state enabling law. In some states there is adequate authority under current law, and in some states additional legislative authority is required (see detailed discussion of state PUC authority and precedent in Sections 8.0 and 9.0 in Volume II). In some states with more traditional regulation of retail electricity sales, especially in coal producing states, the state PUC already has authority to allow for timely cost recovery (including ongoing recovery of cost of capital for construction work in progress and of all costs after construction ends), and there are legislative policy directives to the state PUC to promote clean coal technology investments or the utilization of coal. Some states with competitive retail electricity sales have the authority to impose non-bypassable wires charges to cover stranded asset recovery, deregulation transition costs, and certain other public benefits programs. In these instances, the non-bypassable charge is typically limited to specific purposes so new legislation or state attorney general approval may be required to include recovery of costs from a new IGCC projects through a non-bypassable wires charge.

The availability of a federal loan guarantee under the 3Party Covenant provides the financial motivation for a state PUC (with support from the governor and legislature) to participate in the 3Party Covenant and approve the assured revenue stream. Specifically, the federal loan guarantee provides available financing on more favorable terms and at much lower costs for an IGCC plant. Lower interest rates and a higher debt-equity ratio reduces the amount of higher cost equity in the capital structure and the associated income taxes. Under the 3Party Covenant financing, the cost of capital can be reduced about 30 percent and the cost of energy reduced about 17 percent. Consequently, a strong motivation for state PUC participation is the opportunity to secure IGCC base-load power at a cost that is lower than PC or NGCC alternatives, enabling savings to be passed on to retail customers. Of course, the state PUC will weigh the potential savings against risks that are also passed along to the ratepayers.

In addition, state PUCs are concerned to maintain quality credit ratings of utilities under their jurisdiction. The availability of nonrecourse federally guaranteed financing reduces the pressure on the utility’s capital resources.

Another motivation for state participation is to promote economic development through construction jobs and, in some states, coal mining jobs. IGCC projects produce significant local economic benefits and increase demand for local coal in coal producing states. Furthermore, in some coal producing states, state PUC participation will be in-line with existing legislative policy directives to promote coal use. The availability of federally guaranteed financing for 80 percent of capital costs assures the availability of favorable financing for a coal-fired plant at a time when few new coal plants have been financed.

Equal to the economic advantages, the state PUC's participation facilitates the deployment of more environmentally attractive technology. IGCC technology can cost effectively achieve much lower air pollutant emissions as compared to traditional coal-fired plants, including very low mercury, SO_2, NOx, and particulate emissions, and the potential for relatively cost-effective capture and sequestration of CO_2.

4.23. Equity Investor

The equity investor under the 3PartyCovenant is likely to be either an electric utility company (or municipal utility or rural electric cooperative) or an independent power producer with power sales to a utility or other credit worthy purchaser. The equity investor contributes equity for 20 percent of the Total Plant Investment and obtains a performance guarantee wrap from the EPC contractor.

Since few commercial sized IGCC plants have been deployed, there is a perception of significant technology, construction, and operating risks. Few utilities and independent power producers have been willing to construct PC plants even in lower risk regulated environments over the past 10 years. The hypothesis of the 3Party Covenant is that only when some of these risks are borne by the federal loan guarantor (through non-recourse financing) and the ratepayer (through assured cost recovery after upfront certification and prudence determinations) is it likely that IGCC projects will be financed during this decade.

4.3. Ratepayer Benefits and Protection

Under the 3Party Covenant, ratepayers have the opportunity to benefit from lower cost and less polluting power because of access to lower cost financing. In exchange, ratepayers will take on some of the risks of early adopter commercial scale application of an IGCC power plant. However, these risks are mitigated under the 3Party Covenant by EPC contractor construction guarantees (and underlying equipment vendor warranties), the Line of Credit available for up to 15 percent of Overnight Capital Costs (with a 20 percent equity match), and the state PUC process evaluating the prudence of the IGCC investment decision.[131] As discussed below, it is ultimately up to the state PUC, through a transparent public process, to determine whether the benefits of building a new IGCC power plant under the 3Party Covenant outweigh the risks to ratepayers.[132] The decision

[131] Use of redundant gasifier capacity, which is assumed in the economic assessment in Section 5 below, also provides protection against operational difficulties that might otherwise reduce plant availability.
[132] This report has not attempted to quantitatively evaluate the costs or risks that ratepayers are being asked to take on, or to quantify the benefits that they will receive. Instead the paper outlines qualitatively how IGCC and the 3Party Covenant benefit ratepayers and quantifies the direct economic savings associated

only will be made where there is a need for new base load power identified and will entail weighing the long-term benefits, risks, and cost of 3Party Covenant IGCC against the long-term benefits, risks, and costs of conventionally financed alternative base load generation or conservation options.[133]

4.31. EPC Contract

A primary risk that must be addressed in building a new power plant is construction risk—the risk that the plant is delivered on schedule, on budget, and initially operating up to the agreed upon thermal and environmental performance specifications. In the electricity sector (not necessarily in the industrial sectors), owners generally hire EPC firms to design and build power plants and look to these firms to provide contractual guarantees (performance wraps) to assure the plant will be built and initially operate as expected.

As part of these guarantees, power plant owners generally seek provisions for liquidated damages if the EPC firm does not deliver on its contractual obligations.[134] Liquidated damages are generally expressed as a percentage of project capital cost and tend to be on the order of 10 to 15 percent for PC and natural gas combined cycle power plants for which costs and risks are relatively well known.

Major EPC firms for the electric power industry have considerable experience designing and building conventional power plant technologies such as natural gas combined cycle and pulverized coal. They currently have limited experience designing and building IGCC facilities. The lack of experience is expected to translate into greater upfront design and engineering costs for the first set of commercial IGCC facilities. It also creates additional uncertainty regarding construction costs and timing to deliver a completed plant that meets performance requirements. For this reason, EPC firms have been reluctant to provide performance wraps with liquidated damages provisions for IGCC power plants satisfactory to owners and private lenders. However, when serious commercial interest in IGCC power plants emerges, competing EPC firms will have incentive to offer competitive contracts.

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with 3Party Covenant financing. A comprehensive cost/benefit assessment is beyond the scope of the paper, but may be an appropriate future line of investigation.

[133]The cost risks to the ratepayer of a new IGCC plant would also be significantly diluted by the fact that the plant would make up a small percentage of the total sources of power (generation and purchases) used by a utility. Typical large electric utilities in the U.S. have total sources of power that range between about 50 and 150 million MWh per year. (For example, in 2002 the total sources of power for Cincinnati Gas & Electric were 133 million MWh; Florida Power and Light, 105 million MWh; and PSI Energy, 63 million MWh (see EIA Form 861.) A new 550 MW IGCC facility would generate only about 4 million MWh per year if operating at an 85 percent capacity factor. Therefore, in a worse case scenario, if the cost of energy from an IGCC facility ended up 20 percent more than the cost of energy of an alternative PC plant, it would only represent a 0.5 to 1.6 percent increase in the overall cost of power procurement by the utility, due to the single plant's relatively small share of the total sources of power.

[134] Liquidated damages are used to compensate the owner for economic losses resulting from construction completion problems (delay, underperformance, or failure to complete), such as the cost of replacement power to meet demand that the new plant was intended to serve.

Another complicating factor is that the EPC contractors are not the gasification technology licensors. EPC contractors must be satisfied with the warranty/guarantees from the technology licensor (e.g. GE Energy, ConcoPhillips, or Shell), before providing construction and delivery guarantees. Since IGCC technology licensors receive relatively modest licensing fees (+/-$25 million on a $750 million construction contract) that do not justify significant financial risks, it has been difficult for EPC firms to agree with licensors on technology guarantees that enable them to manage their own risk in putting together performance wraps. Several gasification technology licensors are currently working with the EPC contractors in attempt to resolve this issues and enable EPC performance guarantees to be offered.

Participation under the 3Party Covenant requires development of an EPC performance guarantee satisfactory to the owner, lender, federal guarantor, and state PUC. Ultimately, the details of the guarantee will be negotiated by the parties. In the absence of a real commercial market for IGCC power plants, there has been little incentive to work out guarantee details. By providing favorable economics and financing for IGCC, federal implementation of a 3Party Covenant program will create the serious commercial interest needed for firms to aggressively seek to resolve guarantee issues.

4.32. Construction and Operating Reserve Fund

Another protection that could be used to address concerns about operating performance would be to establish a Construction and Operating Reserve Fund equivalent to at least 10 percent of the Overnight Capital Cost of the project. For a 550 MW IGCC plant with an Overnight Capital Cost of $1,400/kW, the Construction and Operating Reserve Fund would be $70 million.

The Construction and Operating Reserve Fund could provide utility rate stabilization because it would be available to make up cash flow shortfalls in the initial years of operation due to lower than expected plant availability, construction cost overruns, or other operational problems. The Construction and Operating Reserve Fund would cover unexpected costs that are not covered by the EPC wrap and therefore are the responsibility of the owner. This protection could help reduce federal budget scoring requirements and would make it easier for the state PUC to provide assured cash flow. This mechanism is not included in the economic analysis of the 3Party Covenant in this report.

4.33. Line of Credit

An addition protection to ensure the availability of capital at low cost is a Line of Credit to be drawn to fund the owner's unforeseen construction overruns and operating difficulties. The Line of Credit will be incorporated into the base financing and added to the federally guaranteed debt on the same terms and conditions.[135] It is available for an amount up to 15 percent of Overnight Capital Costs and requires matching equity equal to 20 percent of any draws on the credit line (i.e., the same 80/20 debt to equity ratio as allowed in the base financing). The availability of this Line of Credit provides further protections for ratepayers by ensuring the availability of low-cost capital for the project to overcome unforeseen problems. Without the Line of Credit, if additional capital were needed, the owner would be forced to contribute more expensive financing (likely 100 percent equity).

4.34. State PUC Prudence Review

It is the responsibility of the state PUC, through a highly transparent and public process, to evaluate the prudence of the IGCC investment decision, including the feasibility of technology application, before costs are passed along to ratepayers.

The state PUC first conducts a due-diligence certification process, through which it publicly examines the need for power, reliability of the technology, terms and conditions (including performance guarantees and warranties) of contracts with the general contractor and equipment suppliers, level of redundancy to improve reliability (i.e. proposed redundancy of the gasifier systems), and any other technical or financial issues, including the terms and conditions of the federal debt guarantee. This determination establishes the willingness of the state PUC to participate in the 3Party Covenant.

After commencement of plant construction and thereafter, the state PUC conducts ongoing prudence reviews of construction and operating costs. State PUC certification and prudence reviews protect ratepayers and are the basis for the state PUC determining whether to approve recovery of project costs.

As construction expenditures are determined to be prudent, they are included in rate base and project risks associated with such expenditures are borne by ratepayers. Laws in some states with more traditional regulation of electricity retail sales (e.g., Indiana) allow for this type of ongoing review and assured recovery for "clean coal technology" investments. The 3Party Covenant follows Indiana law in this regard, with the entire IGCC plant treated as a clean coal technology investment.

The federal loan guarantor's risks are minimized by the state PUC's procedures for pass-through of adequate revenue to service the guaranteed debt and cover the other project costs. The utility investor receives, under the pass-through procedures, an assured rate of

[135] For this reason, it should be scored in the federal budget the same as the base loan guarantee.

return on investment unless there is a failure to complete an operable plant. It should be noted that there are similar construction and operation risks associated with modern PC plants as well. These include advanced application of pollution control equipment in untested configurations and the potential for CO_2 limitations that would impose higher costs on PC versus IGCC plants. See Section 9.2 in Volume II (discussing state PUC prudence review in detail and providing model state PUC regulatory mechanism.).

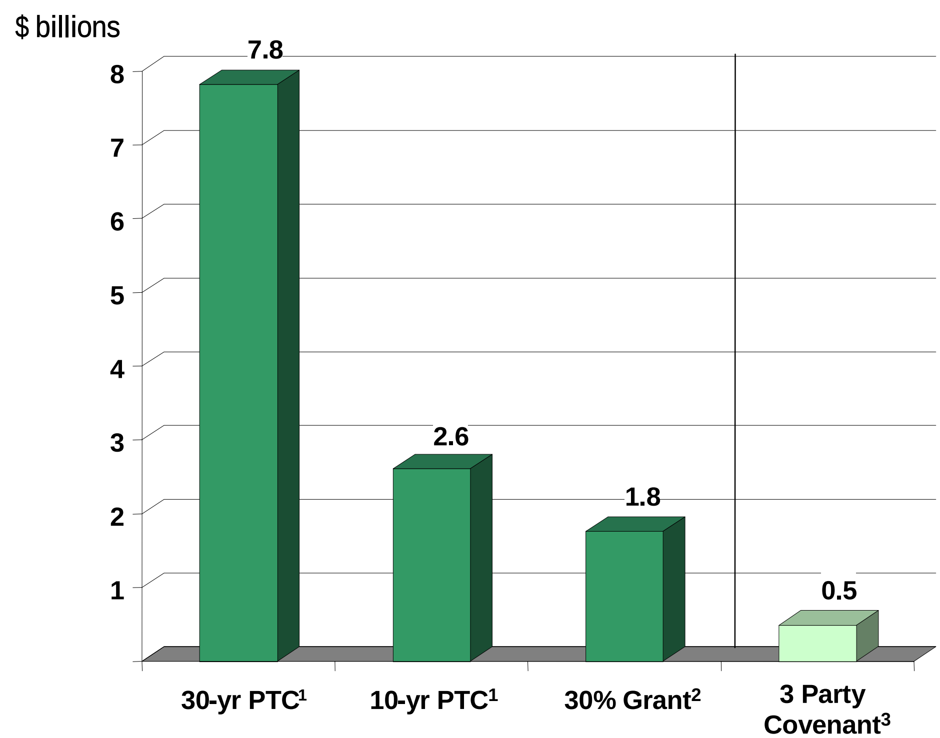
4.4. Federal Budget Scoring

The 3Party Covenant reduces the risk of federal loan guarantees to minimize their budgetary impact and allow a given level of appropriations to support loan guarantees for a larger number of IGCC plants. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (FCRA). FCRA makes commitments of federal loan guarantees contingent upon prior budget appropriations ("scoring") of enough funds to cover the estimated present value cost associated with the guarantees. The present value cost is based on an estimate of the following cash flows at the time the loan guarantee is disbursed:

1. Payments by the Government to cover defaults and delinquencies, interest subsidies, or other payments; and
2. Payments to the Government, including origination and other fees, penalties and recoveries.

State PUC assured utility rate revenues should qualify as a government supported credit. Payments by the Government are estimated based on the dollar amount guaranteed and the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors. The risk of default provides for estimation of the expected payment (the risk of default times the amount guaranteed) to make the scoring determination. The Director of the Office of Management and Budget (OMB) is charged with making this determination, but may elect to delegate the OMB's authority to another agency. To the extent the rating agencies view the 3Party Covenant as reducing the risk of default by providing a state PUC approved revenue stream, the federal budget cost (scoring) of the loan guarantees should be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, then $5 billion of loan guarantees (enough for about 3,500 MW) would cost the federal budget $500 million.

Figure 4-1. Federal Budget Cost of 1 cent/kWh Support for 3,500 MW of IGCC under Different Policy Approaches



[1] PTC = Production Tax Credit equal to 1.0 cent/kWh of generation (10-year PTC program provides significantly less economic benefit than the other programs that provide about 1 cent/kWh over 30 years).
[2] Federal grant equal to 30 percent of total plant investment (equivalent to 0.96 cent/kWh of economic support for 30 years).
[3] Assumes 10 percent scoring of federal guarantees (equivalent to 1.06 cent/kWh of economic support for 30 years).

This budget impact is significantly less than alternative grant or energy production tax credit based incentive programs. As illustrated in Figure 4-1, a one cent/kWh production tax credit provided over a 30 year period (approximately the same economic benefit as provided by the 3Party Covenant) for 3,500 MW of IGCC would cost the federal government $7.8 billion, or sixteen times more than the 3Party Covenant. If provided for only 10 years, the one cent/kWh production tax credit (providing the project significantly less economic benefit than the 3Party Covenant) would still cost $2.6 billion, or more than 5 times more than the 3Party Covenant. Similarly, if a 30 percent federal grant were offered to offset IGCC capital costs, the federal budget cost would be more than 3.5 times more than the budget cost of the 3Party Covenant. The 3Party Covenant loan guarantee approach is significantly less costly to the federal government than these alternative incentive approaches and has the advantage of addressing the major financial obstacles to deployment (e.g., capital availability) that would not be addressed by a production tax credit or grant program. [136]

[136] This is not to suggest that budget cost and capital availability are the only attributes that policy makers should consider. There may be other tradeoffs between a PTC and loan guarantee approach that policy

Under the 3Party Covenant, the primary risk to the federal loan guarantee is a regulatory risk that state PUC determinations regarding cost recovery are modified or overturned at a future date. This regulatory risk, which could be reduced or removed through state legislation, should be viewed by rating agencies as considerably lower than the technology and operating risk associated with development of new IGCC power plant. As a result, the federal budget scoring of a 3Party Covenant loan guarantee program to finance IGCC power plants should be substantially lower than if a federal loan guarantee program were established without clear creditworthiness requirements. Alternative credit enhancement, such as a power purchase agreement with a creditworthy industrial user or utility (investor owned, municipal, or cooperative), through investment grade corporate credit guarantees, or through insurance or some other instrument that substitutes for the state PUC regulatory determinations would be acceptable so long as the risk to the federal loan guarantee is viewed as similar to that associated with regulatory determinations. The key for favorable budget scoring is that the federal guarantee be insulated from the risks of the project to avoid having these risks determinative in the budget scoring calculus. It is recommended that to qualify for 3Party Covenant financing an IGCC project's budget scoring should not exceed 10 percent of loan principal (see Appendix A).

The credit protections of the 3Party Covenant also provide the basis for federal guarantees of 80 percent of the Total Plant Investment. The 80 percent guarantee is similar to the levels in housing, shipbuilding, foreign trade and other federal guarantee programs.[137] Without regulatory determinations or other credit enhancement as protection, it might be more appropriate to cover a smaller percentage of project costs (say 50%) with the loan guarantee. However, by reducing the level of the guarantee, the economic benefits of the loan guarantee program are substantially reduced.[138] The economic benefits are critical for making IGCC cost competitive with PC and providing a basis for state PUCs to make the regulatory determinations required for participation.

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makers may want to weigh, such as the requirements for administering the program and the risks associated with different approaches.

[137] For example, the Federal Ship Financing Program provides up to 87.5 percent loan guarantees for construction, reconstruction, and reconditioning of commercial ships in U.S. shipyards (See, U.S. Department of Transportation, Maritime Administration, *Federal Ship Financing Progra*m, available at: http://www.marad.dot.gov/publications/shipbuild.htm). Similarly, federal housing loan guarantees are available for 100% of low income home loan (See, Section 502 Guaranteed Rural Housing Loan Program, 7 CFR Part 1980). The Export-Import Bank provides loan guarantees for 85-100 percent of the value of U.S. export goods purchased by foreign buyers (See, Export Import Bank of the United States at: http://www.exim.gov/products/loan_guar.html).

[138] As demonstrated in Section 5.5 below, the economic benefits of the 3Party Covenant loan guarantee program result primarily from allowing a greater percentage of low cost debt than would be possible under conventional financing (80% versus 55%). There is some economic benefit from the lower cost of federally guaranteed debt (which costs about 1% less than typical utility debt), but this benefit is dwarfed by the benefit from shifting to a greater percentage of debt under the 3Party Covenant.

4.5. State Adoption and State PUC Participation

In states with more traditional retail electricity sales regulation, state PUCs protect retail customers of a utility by assuring that reliable service is available at reasonable rates. In balancing ratepayer and investor interests, state PUCs employ a variety of review procedures and cost recovery mechanisms, including, in some states, review and recovery of costs during construction and cost recovery through adjustment clauses. In such a state, IGCC project cost recovery under the 3Party Covenant is through adjustment clauses in the rates paid by all retail customers of the regulated utility. Indiana, for example, already has adopted procedures with many of these features for pollution control and clean coal technology investments.[139]

In states with competitive retail electricity sales, state PUCs are implementing competition, although often a variety of cost recovery mechanisms (e.g., for transition costs, stranded asset costs, and public benefit programs) remain in place. In such a state, IGCC plant cost recovery under the 3Party Covenant is through an adjustment clause in a non-bypassable wires charge paid by all retail electric customers, e.g., in the service area of the distribution utility selling the IGCC power. Ohio already provides for non-bypassable wires charges for transition costs and certain public benefit costs.[140]

Within these constructs, the specific procedures that must be established by the state PUC for participation need to include the following elements (see Section 9.0 in Volume II for a detailed discussion of these requirements and how they relate to existing state laws):

1. Before any construction begins, the state PUC reviews the equity investor's detailed plans for the IGCC plant in order to determine whether the plant is in the public convenience and necessity. Determination of the public convenience and necessity includes consideration of several factors concerning the likely benefits and costs of the proposed IGCC plant and the need for base load power. As part of this consideration, the state PUC reviews the terms and conditions of the federal loan guarantee and the impact of the 3Party Covenant on the cost of financing the IGCC plant and the cost of electricity to ratepayers for alternative projects. Based on a satisfactory balancing of these factors, the state PUC issues a certificate of public convenience and necessity for the new plant. In the certificate, the state PUC establishes a fixed return on equity for the project and approves the use of an adjustment clause for future recovery of incurred costs (including recovery during construction of return on capital on construction work in progress (CWIP)).

[139] See, e.g., IC 8-1-6.8 (cost recovery during construction), 8-1-8.7-3 (certification of clean coal technology), 8-1-8.7-7 (ongoing review), 8-1-8.7-8 (assurance of recovery of approved costs), and 8-1-8.8-11 and 8-1-8,8-12 (financial incentives for clean coal technology and new energy generating facilities).)

[140] See, e.g., ORC 4928.37(A)(1)(b), 4928.61, and 4933.83.

2. After issuance of a certificate and as construction progresses, the state PUC periodically conducts a prudence review on an expedited basis and approves the portion of the IGCC plant constructed during the preceding period. As each portion of construction expenditures (CWIP) is approved in the ongoing review, the return on capital for the approved expenditures becomes recoverable on an ongoing basis through, and is reflected in, the approved adjustment clause.

   If the duration of each periodic (e.g., six-month) review proceeding is limited (e.g., to three months), return on capital during construction is recovered within a relatively short period (e.g., three to nine months) after incurrence of the associated capital expenditures. Since most of the cost of capital is recovered on an ongoing basis during construction, a much smaller amount is accrued, added to the capital investment in the plant, and ultimately recovered through amortization.

   As each portion of the construction expenditures is reviewed and approved, future recovery of these costs (including the related return on capital) cannot thereafter be challenged, except in limited circumstances. For example, issues concerning excessive cost, inadequate quality control, or inability of the plant to continue to operate properly cannot be raised after the costs are approved. In this way, the state PUC's review and protective approval is updated during and after plant construction. In the event of failure to complete an operable plant, the debt-funded portion of the approved pre-construction and construction expenditures will be fully recoverable, but the equity-funded portion will be only 50 percent recoverable.

   Disbursement of the federally guaranteed loan is coordinated with the ongoing review process. As each portion of construction expenditures is reviewed and approved for recovery through the adjustment clause, the federally guaranteed loan is disbursed for the debt-funded share of that portion of the expenditures.

3. After completion and commencement of operation of the new IGCC plant, the state PUC periodically conducts, on an expedited basis, a prudence review of the plant's operating costs during the preceding period. As the operating costs are approved in the ongoing review, the approved operating costs become recoverable on an ongoing basis through, and are reflected in, the approved adjustment clause. Coordinated with the approval and pass-through of operating costs, the depreciation and amortization of the previously approved construction expenditures and associated return on capital also become recoverable through, and reflected in, an approved adjustment clause. The state PUC requires the IGCC plant owner to segregate the entire revenue stream from the approved adjustment clause and place the revenues in a separate account that can only be used to pay project costs, including return on capital.

Under these procedures, state PUC certification and approval creates an assured, dedicated revenue stream to cover the risks of the IGCC plant (see detailed discussion in

Volume II, Section 9). From the standpoint of the federal government, this assurance provides enhanced credit worthiness and strong protection against loan default. From the standpoint of the equity investor, this assurance enables underwriting of the federally guaranteed, non-recourse loan in the context of a higher debt-equity ratio (80/20) than available under traditional utility financing of (55/45). From the standpoint of purchaser of the long-term debt, the federal guarantee provides a “AAA” credit rating.

5.0. IGCC ECONOMICS AND IMPACT OF 3PARTY COVENANT

Commercial investment in IGCC technology will require that cost of energy output be competitive with other generation technologies. In particular, IGCC must be cost competitive with PC generation so that developers looking to build coal capacity and state PUCs that approve cost recovery in utility rates see IGCC as a legitimate choice. The capital investment required to build the next generation of IGCC plants is generally estimated to be approximately 20 percent higher than investment required to build the next generation of PC plants, which translates into 10-15 percent higher energy cost. The 3Party Covenant more than offsets this cost differential with lower cost of capital by allowing for 80 percent federally guaranteed debt, a significantly higher percentage of debt at a lower interest rate than available under traditional utility financing. The discussion below reviews the basic cost components of IGCC power plants, summarizes IGCC cost data and estimates, and demonstrates how the 3Party Covenant reduces IGCC cost of energy to levels below PC cost of energy.

5.1. Power plant cost components

The cost of energy ($/MWh) produced by an IGCC or other power plant is a function of the Total Plant Investment, Owner's Costs, operating cost, fuel costs, and Cost of Capital. Each of these cost components is described below along with a review of how these costs are used to calculate cost of energy.

5.11. Total Plant Investment

Total Plant Investment is the total investment required to build a power plant. It includes the "Overnight Capital Cost," which is the cost of erecting the plant, plus Construction Financing Costs.

5.12. Overnight Capital Costs

Overnight Capital Costs refer to the cost of erecting the plant, including construction contingencies, but not considering Construction Financing, Owners Costs, or Cost of Capital. Typically, power plant developers hire an EPC firm to provide a cost bid for designing and building a power plant facility, which includes the firm's engineering and construction fees and procurement costs, and is the basis for estimating the Overnight Capital Cost. Most studies that compare capital costs of different types of power plants refer to the Overnight Capital Cost as the basis for comparison. The Overnight Capital Cost is sometimes referred to as the Total Plant Cost, or Engineering, Procurement, and Construction cost (EPC).

5.13. Owner's Costs

In addition to the cost of constructing a new coal power plant (IGCC or PC), there are costs associated with developing and starting up the facility. These costs, referred to as Owners Costs, include things such as the cost of land, initial engineering, legal, site improvements, and transmission interconnects, as well as start-up costs such as the initial chemicals (primarily for emissions control) and fuel, security, personnel training, and initial operational testing of the facility. These costs can very significantly from one facility to the next depending on the location, site characteristics, plant design, and other factors. Although a generalized estimate of Owner's Costs will not accurately depict all facilities, it is useful to assume some level of cost in order to achieve an estimate of Total Plant Investment.

For the purposes of calculating energy costs in this report, Owner's Costs are assumed to be 10 percent of Overnight Capital Costs for both PC and IGCC plants. Owners Costs are accounted for in the Levelized Carrying Charge, which is discussed in Section 5.17 below and calculated in Appendix B.

5.14. Construction Financing

In addition to Owners Costs, building a power plant requires financing during the construction period. Construction Financing Costs refer to the cost of equity and debt financing during the design and construction period, which is typically about 4 years (about two years of actual construction) for both IGCC and PC power plants.

Construction Financing Costs are important because, unless they are recovered during the construction period (as return on capital on Construction Work in Progress (CWIP)), they are accrued (the accrual is sometimes described as the Allowance for Funds Used During Construction (AFUDC)) and rolled-into the ultimate cost of the plant that must be paid for with long-term financing. Typically, Construction Financing Costs that are accrued for a coal power plant (IGCC or PC) are about 10 percent of the Overnight Capital Cost.

For the purposes of calculating energy costs in this report, Construction Financing Costs are calculated assuming a four year design and construction period with level investments each year. Construction Financing Costs are added to the Overnight Capital Cost to calculate Total Plant Investment. Construction Financing Costs are calculated as part of the Levelized Carrying Charge (see Section 5.17 below and Appendix B).

5.15. Cost of Capital

Cost of Capital refers to the weighted costs of common stock, preferred stock and long-term debt used to finance a power plant project (i.e., equity returns and debt interest rate). A typical capital structure for a utility company is about 45 percent equity (common and preferred stock) and 55 percent long-term debt.[141] In regulated markets, typical after tax returns allowed for utilities are around 11.5 percent.[142] With a federal tax rate of 34 percent and average state tax rate of 4.2 percent (for a combined 38.2 percent tax rate), the pre-tax return required to achieve an 11.5 percent after-tax equity return is 18.6 percent. Mid-grade utility debt in early 2004 yielded around 6.5 percent.[143]

5.16. Operating costs

Power plant operating costs are typically broken into fuel costs and non-fuel operating and maintenance (O&M) costs. Although coal is a relatively inexpensive fuel source, fuel costs are still a significant operating cost component, typically accounting for 20 to 25 percent of the cost of energy from an IGCC or PC power plant. Fuel costs (on a $/MWh of output basis) are a function of the price of the fuel and the heat rate or efficiency[144] of the power plant. More efficient plants use less fuel per MWh of generation and, assuming the same delivered coal price, have lower fuel costs. As noted above, the efficiency of current IGCC technology is similar to the efficiencies of new PC power plants (both tend to be 35-42 percent efficient), so fuel costs will be likely be similar for IGCC and PC for the next generation of IGCC. Assuming IGCC efficiency improves as the technology is commercially deployed, IGCC fuel costs should decline relative to PC.

O&M costs include labor, maintenance material, administrative support, consumable materials (such as chemicals and water), and waste disposal. O&M costs typically account for about 20 percent of the cost of energy from an IGCC power plant and are generally similar to PC plant O&M costs. Although different gasifier designs and plant-specific characteristics can affect O&M costs, for the purposes of calculating energy costs in this report, O&M costs for both IGCC and PC plants are assumed constant at $8/MWh.

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[141] Regulatory Research Associated, Inc., Jul. 7, 2003 (providing annual data on the equity % of electric utility capital structures (49.72% YTD July 2003) and average authorized equity returns (11.38% YTD July 2003).)
[142] Id.
[143] Based on personal communications with Lehman Brothers.
[144] Power plant efficiency is a measure of the amount of electricity produced from a given amount of fuel. The ratio of fuel to electricity is call the heat rate. Heat rates and efficiency can be expressed in terms of the lower heating value (potential energy in a fuel if the water vapor from combustion of hydrogen is not condensed) of the fuel, or the higher heating value (the maximum potential energy in dry fuel) of the fuel. The percent efficiency is calculated based on dividing the heat rate (Btu/kWh) into 3,412 Btu/kWh.

5.17. Levelized Carrying Charge

Each of the costs discussed above, Total Plant Investment (made up of Overnight Capital Costs and Construction Financing), Owner's Costs, fuel, and O&M costs all contribute to the cost of producing energy (expressed as $/MWh) from a new IGCC or other power plant. Calculating the cost of energy also involves calculating (or assuming) a "Levelized Carrying Charge" for capital, which is the average annual capital cost over the life of the plant, taking into account loan amortization, financing costs (construction and long-term), taxes, and depreciation.

Most studies evaluating energy costs under traditional financing scenarios for coal power plants simply assume around a 15 percent Levelized Carrying Charge for capital and multiply this amount by the Total Plant Investment to attain an annual capital charge, which is divided by annual generation to calculate the capital component of energy costs. For this analysis, however, the Levelized Carrying Charge for capital has been calculated with assistance from Professor Robert Williams of Princeton University by applying the EPRI Electric Supply Technical Assessment Guide (TAG) methodology as described in the June 1993 TAG report.[145]

The calculation of Levelized Carrying Charge includes incorporation of a 10 percent Owner's Cost. The Levelized Carrying Charge assumes a four year construction period and equal annual investments in the traditional utility financing scenarios and assumes no construction financing cost in the 3Party Covenant scenarios due to cost recovery during construction (CWIP) under the 3Party Covenant. Calculation of a Levelized Carrying Charge is essential for evaluating the impact of the 3Party Covenant on cost of energy because the 3Party Covenant economic savings manifest in a reduction in the Levelized Carrying Charge. Appendix B illustrates the calculation of Levelized Carrying Charges under both the traditional utility financing and 3Party Covenant scenarios.

[145] This methodology accounts for the impacts of different financing assumptions on the overall cost of electricity from power plants and allows for appropriately analyzing the potential economic impacts of the 3Party Covenant program (Section 5.5 below analyzes the cost of energy impacts of the 3Party Covenant).

5.2. Published IGCC Capital Cost and Efficiency Estimates

Because there is a lack of commercial experience with IGCC (so that there are not yet well-established cost and performance characteristics or a standardized commercial design), there is considerable variability in IGCC cost estimates. Different gasifier technologies, IGCC design configurations, and fuel feedstocks have different cost and efficiency characteristics. Consequently, a generalized cost or efficiency estimate for IGCC technology may not be representative of all IGCC systems. Nonetheless, by looking at the documented performance of demonstration IGCC facilities operating today and reviewing government, academic, and industry cost assessments for the next generation of facilities, a reasonable range of expected IGCC cost and performance characteristics can be developed.

Table 5.1 lists IGCC capital cost and efficiency data from the two demonstration plants in the U.S., a number of recent studies, and two regulatory filings. The estimates and data presented are not comprehensive, but represent a survey of reported information from a variety of sources. The data demonstrate a range of IGCC costs and efficiencies across different studies and technologies. The capital cost estimates range from around $1,100/kW to over $1,700/kW and the efficiencies range from 32 to 45.5 percent. Some of the variation is the result of not all studies including the same costs,[146] some reflects different costs associated with the different gasifier technologies, and some simply reflects uncertainty regarding actual costs. Cost data from the existing IGCC plants in the U.S. and Europe, Wabash, Polk, and Buggenum, are at the high end of the spectrum, which would be expected of first-of-a-kind demonstration projects with research objectives. The estimates from the two regulatory filings shown are also significantly higher than the estimates provided by the academic, industry, and government estimates. These higher cost estimates likely result from inclusion of Owner's Costs, Construction Financing, and other plant specific costs[147] that are not typically included in comparative studies. They may also be indicative of the conservative approach taken by companies reviewing new technologies.

[146] Many of the studies are not explicit about what costs are included in their capital cost estimates. Some represent Overnight Capital Cost estimates, while others may include Owners Costs and Construction Financing Costs.

[147] In the case of the Prairie State filing, for example, the costs reflect the intended use of coal with very high ash content.

Table 5-1. Selected Published IGCC Capital Costs and Plant Efficiencies

Demonstration Plants	Gasifier Technology	Capital Cost $/kW	Efficiency % (Btu/kWh HHV)
Wabash Generating Station[1]	Concophillips	1,680	40% (8,600)
Polk Power Station[2]	GE Energy quench	1,790	37% (9,100)
NUON IGCC Plant[3]	Shell w/ Heat Recovery	1,750	41.5% (8,300)
Selected Published Estimates			
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[4]	GE Energy quench	1,100	37% (9,300)
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[4]	Concophillips	1,140	39% (8,640)
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[4]	Shell w/ Heat Recovery	1,420	41% (8,370)
IEA/Foster Wheeler (2003)[5]	GE Energy quench	1,187	36% (9,400)
IEA/Foster Wheeler (2003)[5]	Shell w/ Heat Recovery	1,371	41% (8,370)
Jacobs consultancy (No shift, no capture) (2003)[6]	GE Energy quench	1,164	41% (8,384)
Jacobs consultancy (Shift, no capture) (2003)[6]	GE Energy quench	1,169	39% (8,777)
EIA Annual Energy Outlook (2004 Assumptions)[7]	unspecified	1,383	43% (8,000)
NETL/EPRI Parsons Case 9A (E-Gas w/ F turbine) (2002)[8]	ConcoPhillips	1,070	40% (8,609)
NETL/EPRI Parsons Case 3B (E-Gas w/ H turbine) (2002)[8]	ConcoPhillips	1,262	43% (7,915)
NETL PED-IGCC-98-001(revised June 2000)[9]	Concophillips	1,365	45% (7,583)
NETL PED-IGCC-98-002(revised June 2000)[9]	Shell w/ Heat Recovery	1,371	45.7% (7,466)
NETL PED-IGCC-98-003(revised June 2000)[9]	GE Energy quench	1,307	39.7% (8,595
NETL PED-IGCC-98-003(revised June 2000)[9]	GE Energy w/ Heat Recovery	1,439	43.5% (7,844)
David & Herzog Year 2000 Plant (2000)[10]	unspecified	1,401	40% (8,506)
David & Herzog Year 2012 Plant (2000)[10]	unspecified	1,145	45% (7,513)
EPRI Shell-HR output maximized, Illinois # 6 coal (1998)[11]	Shell w/ Heat Recovery	1,340	41% (8,225)
EPRI Shell-HR, output maximized Pittsburgh # 8 coal (1998)[11]	Shell w/ Heat Recovery	1,274	43% (7,881)
EPRI GE Energy-HR, output maximized, Illinois # 6 coal (1998)[11]	GE Energy w/ Heat Recovery	1,314	42% (8,214)
EPRI GE Energy-HR, output maximized, Pittsburgh # 8 coal (1998)[11]	GE Energy w/ Heat Recovery	1,247	42% (8,113)
EPRI GE Energy-Q, output maximized, Illinois # 6 coal (1998)[11]	GE Energy quench	1,201	35% (9,622)
EPRI GE Energy-Q, output maximized, Pittsburgh # 8 coal (1998)[11]	GE Energy quench	1,148	37% (9,316)
EPRI ConocoPhillips-HR, output maximized, Illinois # 6 coal (1998)[11]	ConcoPhillips	1,225	41% (8,248)
EPRI ConocoPhillips-HR, output maximized, Pittsburgh # 8 coal (1998)[11]	ConcoPhillips	1,171	42% (8,066)
Regulatory Filings			
SFA Pacific BACT Analysis of Prairie State (4 gasifiers)[12]	GE Energy quench	1,795	32% (10,622)
SFA Pacific BACT Analysis of Prairie State (10 gasifiers)[12]	GE Energy quench	1,516	32% (10,576)
SFA Pacific BACT Analysis of Prairie State (4 gasifiers)[12]	ConcoPhillips	1,876	36% (9,492)
SFA Pacific BACT Analysis of Prairie State (10 gasifiers)[12]	ConcoPhillips	1,584	36% (9,451)
WEPCO Elm Road Proposal[13]	GE Energy quench	1,739	Unspecified

[1] DOE, Clean Coal Technology Topical Report Number 20, “The Wabash River Repowering Project—an Update,” September 2000.
[2] NETL, "Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report," August 2002, p. ES-6. Cost estimate based on direct cost escalated to 2001 dollars.
[3] Plant Data provided by Shell Global Solutions.
[4] Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants), "Summary of Recent IGCC Studies of CO2 Capture for Sequestraiton," Presented at Gasification Technologies Conference, San Francisco, CA, October 14, 2003.
[5]Foster Wheeler Energy Ltd, 2003; "Potential for Improvement in Gasification Combined Cycel Power Generation with CO_2 Capture," IEA Greenhouse Gas R&D Programme, Report Number PH4/19, May 2003.
[6]John Griffiths and Stephen Scott of the Jacobs Consultancy, "Evaluation of Options for Adding CO2 Capture to ChevronTexaco IGCC," Gasification Technologies Conference, San Francisco, CA, October 12-15, 2003.
[7]EIA, Assumptions to the Annual Energy Outlook 2004, p. 71.
[8]NETL/EPRI, "Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal," December 2002; "Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal," Interim Report, December 2000.
[9]NETL, Process Engineering Division, PED-IGCC-1988, Revised June 2000.
[10]Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.
[11]Neville Holt (EPRI), "IGCC Power Plants--EPRI Design & Cost Studies," Presented at EPRI/GTC Gasification Technologies Conference, San Francisco, CA, October 6, 1998; results shown are for study cases where maximum attainable gas turbine outputs within pressure ratio and temperature constraints were analyzed.
[12]SFA Pacific, Inc., “Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station,” May 11, 2003, p. 35.
[13]Public Service Commission of Wisconsin and Department of Natural Resource, "Final Environmental Impact Statement, Elm Road Generating Station--Volume 1," July 2003, Chapter 2, p. 12.

5.21. Impact of Coal Rank on Capital Cost and Efficiency

One variable that affects IGCC costs and efficiency is the rank and quality of the coal feedstock. Generally, bituminous coal and petroleum coke fuel feedstocks provide the lowest-cost IGCC operation. These higher rank coals can be gasified most efficiently, which reduces the required size (cost) of fuel handling and gasifier equipment. Table 5-2 illustrates Overnight Capital Cost and efficiency estimates for the ConocoPhillips IGCC system presented at the 2002 Gasification Technologies Conference as Summarized by EPRI. As is illustrated, the lower rank coals (sub-bituminous and lignite) increase the cost and reduce the efficiency of the IGCC plant.

The various gasification technologies accommodate different coal ranks with different levels of impact. For example, dry feed systems (Shell technology), unlike slurry feed systems, have less stringent requirements on ash and water content of coal and therefore a wider feed quality window with the ability to take low rank coal with little downgrade in efficiency and relatively small increase in cost. In China, a gasification project using a dry feed system will be using coal with over 30 percent ash.[148]

Table 5-2. Cost and Efficiency Estimates for ConocoPhillips Gasifier using Different Coals

Fuel Feedstock	Overnight Capital ($/KW)	Heat Rate (Btu/kWh)
Petroleum Coke	1,160	8,380
Bituminous Coal (Pitts # 8)	1,140	8,380
Bituminous Coal (Ill # 6)	1,240	8,883
Sub-Bituminous Coal (Powder River Basin)	1,410	9,553
Lignite Coal	1,580	10,224

Source: Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants), "Summary of Recent IGCC Studies of CO_2 Capture for Sequestraiton," Presented at Gasification Technologies Conference, San Francisco, CA, October 14, 2003, (referencing E-Gas IGCC Estimates for Domestic US Coals from Gasification Technologies 2002).

[148] Personal communication with Shell Global Solutions.

5.22. Gasifier Redundancy

Another important issue in designing IGCC power plants for commercial operation is assuring that they operate with high availability.[149] To be viewed as a viable technology for commercial electricity generation, power plant technologies generally need to achieve availabilities around 90 percent.[150] Achieving this level of availability with current gasification technologies is generally believed to require redundant gasifier capacity, which increases the cost of IGCC facilities, or a back-up fuel supply such as natural gas. Table 5-3 provides cost estimates based on a presentation by EPRI at the 2003 Gasification Technologies Conference summarizing capital cost estimates for different gasification technologies utilizing bituminous coal and assuming a redundant gasifier--e.g., a dual-train system with two gasifiers that each feed a combustion turbine and the addition of a spare gasifier available to feed either CT when needed. This configuration is expected to enable IGCC facilities to operate above 90 percent availability and has been proven successful for very high availability at the Eastman Chemicals gasification facility in Kingsport, Tennessee.

Table 5-3. Capital Cost Estimates Assuming Redundant Gasifier (Dual-Train IGCC with 1 Spare Gasifier)

Gasification Technology	Overnight Capital Cost Range ($/KW)	Approximate Avg. Captial Cost ($/kW)
GE Energy Quench	1,160--1,340	1,270
GE Energy Heat recovery	1,400--1,500	1,450
ConocoPhillips	1,230--1,390	1,300
Shell*	1,570--1,670	1,620

* Shell questions the need for a spare gasifier in its configuration. Shell has indicated that because of its different design, its system can achieve over 90 percent availability without a redundant gasifier.

Source: Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants), "Summary of Recent IGCC Studies of CO_2 Capture for Sequestraiton," Presented at Gasification Technologies Conference, San Francisco, CA, October 14, 2003.

149 Availability is a measure of the percentage of time in a period during which a plant was actually running at full capacity or, if not running, fully available to run. The term is used to describe the reliability of a power plant and its component systems.

150 See SFA Pacific, p. 20, which states: "SFA pacific anticipates that a 2-year record (at least) of 92+% availabilities (plus demonstrated economics comparable to PC power plants) will be required to convince financial institutions that the risk in financing IGCC projects is comparable to that of PC projects."

The EPRI summary indicates that the cost of IGCC systems with a redundant gasifier is estimated between $1,160/kW and $1,670/kW, with the costs lowest for the GE Energy technology and highest for the Shell technology. This assessment assumes a redundant gasifier available for 50 percent of the plant turbine capacity. Studies have indicated that under different configurations (such as 3 or 4 operating and one spare gasifier) with less redundancy, high availabilities may be achievable at reduced cost.[151] Shell claims that its technology does not require extended, planned outages for refractory replacement, and therefore may be able to achieve over 90 percent availability without spare gasifier capacity, which will reduce its cost.[152]All companies are refining their cost estimates based upon the most current engineering and experience.

5.23. Repowering and Refueling

Critical in the cost of developing IGCC is whether a project is being developed on a greenfield site or is a repowering of an existing coal facility or refueling of an existing natural gas combined cycle facility. Repowering of existing coal facilitates may allow developers to take advantage of existing coal handling, electricity interconnect, and steam turbine facilities to reduce the cost of the project, while refueling allows utilization of the entire existing natural gas combined cycle power block. As discussed in Section 3.4 above, refueling of an existing natural gas combined cycle power block, which accounts for 30 to 35 percent of IGCC capital costs but requires modification to refuel to syngas, can reduce the cost of IGCC development when the NGCC plant or turbine are available at discount prices.

5.24. Planning for CO_2 Capture

Another important consideration in designing IGCC systems is the extent to which the design accommodates reductions in the cost of future CO2 emissions control. Doing so could involve, for example, ensuring the plant footprint could handle the additional equipment required for CO2 capture, incorporating shift reactors into the long term engineering plan of the gas clean-up processes, and evaluating the appropriate sizing of the ASU, coal handling, and turbine equipment to optimize for operational changes associated with beginning to capture CO2 at the facility.[153]

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[151] Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants), "Summary of Recent IGCC Studies of CO_2 Capture for Sequestration," presented at Gasification Technologies Conference, San Francisco, CA, Oct. 14, 2003.

[152] Since 2001, Shell has licensed its coal gasification technology to more than 10 end-users in the chemical industry and all of them have single gasifer designs and are planning to run at over 90 percent availability. (Comments received from Shell on February Draft report).

[153] A study by Parsons indicates that design modifications (including adding a parallel air compressor to the ASU, removing the COS hydrolysis reactor, inserting two shift reactors, and expanding the Selexol process) to minimize future CO_2 capture costs could be incorporated into IGCC facilities for an additional capital cost of about 5% and would have very little impact on plant operation prior to actual CO_2 capture. Pre-investing for CO_2 capture is estimated to save about 25% in terms of future cost of energy with capture. See, Parsons/EPRI, “Pre-Investment of IGCC for CO2 Capture with the Potential for Hydrogen Co-Production,” presented at Gasification Technologies 2003, San Francisco, CA, Oct. 2003.

5.3. Cost Estimates from Technology Suppliers

To assist in the development of IGCC cost and performance information, data requests were sent to each of the major suppliers of entrained flow gasification technologies, including GE Energy, ConocoPhillips, and Shell. The requests asked for capital and operating costs, efficiency, and availability information for both a new IGCC plant and an IGCC plant developed under an NGCC refueling scenario. GE Energy responded to the request and provided the data summarized below and Shell responded to the request by providing comments on the February Draft Report relating to its technology.

5.31. GE Energy

GE Energy provided cost and performance data for a new plant assuming three coal gasification trains (2 operating and 1 spare) and configured with Radiant Syngas Cooling (as opposed to a quench cooling system). The analysis assumed a power block consisting of two GE frame 7FA combustion turbines and a single steam turbine. The results provided by GE Energy for this configuration are illustrated in Table 5-4.

Table 5-4. GE Energy Data for New IGCC Plant

Net power output	564.9 MW
Investment Cost*	$772,000,000
Overnight Capital Cost*	$1,367/kW
Fixed Operating Cost	$22.9/kW-yr ($3.08/MWh at 85% capacity factor)
Variable Operating Cost	$3.90/MWh
Heat Rate	8717 Btu/kWh HHV
Efficiency	39.1% HHV
IGCC Availability	93.8% without backup fuel firing
IGCC Availability	95.0% with backup fuel firing

* This does not include contingency, EPC fee, sales tax or owner's cost.

GE Energy also provided information on the cost and performance of an IGCC developed in a natural gas combined cycle refueling scenario, which is illustrated in Table 5-5.

Table 5-5. GE Energy Data for NGCC Refueling Scenario

Net power output	541 MW
Investment Cost*	$537,000,000
Overnight Capital Cost*	$993/kW
Fixed Operating Cost	$22.9/kW-yr ($3.08/MWh at 85% capacity factor)
Variable Operating Cost	$3.90/MWh
Heat Rate	9102 Btu/kWh HHV
Efficiency	37.5% HHV
IGCC Availability	93.8% without backup fuel firing
IGCC Availability	95.0% with backup fuel firing

* Cost of gasifier construction and integration. This does not include contingency, EPC fee, sales tax or owner's cost. This cost includes an allowance for converting the CT combustors and controls to allow firing on either natural gas or syngas.

5.4. Reference Cases

The discussion above illustrates the disparity in Overnight Capital Cost and efficiency estimates for IGCC, how different gasification technologies and different feedstocks impact costs, and several design considerations (gasifier redundancy, readiness for CO_2 capture, and greenfield site vs. repowering) that can influence IGCC plant costs. The bottom line is that no single IGCC cost estimate or performance characteristic can accurately depict the spectrum of possible future IGCC facilities. At the same time, however, the data and estimates provide reasonable cost and performance ranges for evaluating the impact of the 3Party Covenant on IGCC cost competitiveness.

Based on the studies above and discussions with industry experts, reference IGCC, PC and NGCC power plants were developed to illustrate the 3Party Covenant impact on the cost of energy. Table 5-6 illustrates capital and operating parameters and a calculated cost of energy for a number of representative IGCC power plants, all assuming the availability of redundant gasifier capacity to provide high plant availability. Included in Table 5-6 is the Reference IGCC case, which is intended to represent a reasonable middle ground estimate of the cost and performance characteristics of the next set of IGCC facilities that will be built and is in line with other published estimates and the recent data received from technology suppliers.

The Reference IGCC plant is assumed to have a $1,400/kW Overnight Capital Cost and to be designed and constructed over four years. The reference IGCC plant is assumed to operate at 39% efficiency and have O&M costs of 8 $/MWh. Table 5-6 also provides three generic alternative scenarios at different capital costs, and three specific examples with different gasifier technologies based on information on IGCC's with redundant gasifier technology presented by EPRI at the 2003 Gasification Technology Conference and provided by technology vendors.[154]

Table 5-7 illustrates capital and operating parameters and a calculated cost of energy for a series of NGCC and supercritical PC power plant scenarios. Reference case NGCC and PC cases are highlighted along with three alternative scenarios. For the NGCC case, the representative plant is based on a facility operating at a 50 percent capacity factor, which is a reasonable level of operation for a load-following natural gas plant with delivered natural gas prices averaging $4.50/mmBtu.[155]

[154] The EPRI examples use capital cost and heat rate information taken from: Neville Holt, George Booras (EPRI) and Douglas Todd (Process Power Plants), "Summary of Recent IGCC Studies of CO_2 Capture for Sequestraiton," presented at Gasification Technologies Conference, San Francisco, CA, Oct. 14, 2003.

[155] Changing natural gas prices dramatically affect the economics of NGCC by changing variable costs and changing how much a plant operates during the year. The amount of time a plant operates is determined by how its variable costs compare with the variable costs of other available power plants, which affects where the plant is in the dispatch order. Therefore, changes in natural gas prices can significantly change the capacity factor of a NGCC plants, because the fuel costs are a variable cost.

Table 5-6. Cost of Energy Estimates for IGCC Power Plants under Traditional Financing

	IGCC Reference[1] (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)	IGCC 1[2] (2+1 gasifiers, $1,200/kW; 85% CF 42% Eff.)	IGCC 2[2] (2+1 gasifiers, $1,400/kW; 75% CF; 39% Eff.)	IGCC 3[2] (2+1 gasifiers, $1,600/kW; 85% CF; 39% Eff.)	IGCC 4[3] ConocoPhil (2+1 gasifiers)	IGCC 5[3] GE Energy Q (2+1 gasifiers)	IGCC 6[4] Data from GE Energy (2+1 gasifiers)	IGCC 7[5] Shell (2+1 gasifiers)
Design and Construction								
Plant Size (MW)	**550**	550	550	550	550	550	564.9	550
Overnight Capital Cost ($/kW)	**$1,400**	$1,200	$1,400	$1,600	$1,300	$1,270	$1,367	$1,620
Total Plant Investment ($/KW)[6]	**$1,524**	$1,306	$1,524	$1,742	$1,415	$1,383	$1,488	$1,764
Operation								
Fuel cost ($/mmBtu)	**$1.25**	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
Plant Efficiency (%)	**39%**	42%	39%	39%	40%	36%	39%	41%
Heat Rate (Btu/kWh HHV)	**8,700.00**	8,200.00	8,700.00	8,700.00	8,550.00	9,450.00	8,717.00	8,370.00
Plant Capacity Factor (%)	**85%**	85%	75%	85%	85%	85%	85%	85%
Annual Generation (MWh)	**4,095,300**	4,095,300	3,613,500	4,095,300	4,095,300	4,095,300	4,206,245	4,095,300
Financing								
Percentage Debt	**55%**	55%	55%	55%	55%	55%	55%	55%
Debt Interest Rate	**6.5%**	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Percent Equity	**45.0%**	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
After tax Equity Return	**11.5%**	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%
Tax rate (Federal & State)	**38.2%**	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%
Pre-tax Equity Return	**18.6%**	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%
Pre-tax WACC	**11.9%**	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%
Levelized Carrying Charge[7]	**12.3%**	12.3%	12.3%	12.3%	12.3%	12.3%	12.3%	12.3%
Estimated Cost of Energy								
O&M (cent/kWh)	**0.80**	0.80	0.80	0.80	0.80	0.80	0.69	0.80
Fuel (cent/kWh)	**1.09**	1.03	1.09	1.09	1.07	1.18	1.09	1.05
Capital (cent/kWh)	**2.52**	2.16	2.85	2.88	2.34	2.28	2.46	2.91
Cost of Energy (cent/kWh)	**4.40**	4.0	4.7	4.8	4.21	4.26	4.24	4.76

[1]Reference case developed by authors to be representative generic IGCC plant.

[2]Generic alternative IGCC cases assuming a spare gasifier.

[3]IGCC cost and performance information taken from: EPRI, "Summary of Recent IGCC Studies of CO2 Capture for Sequestration, Presented at Gasification Technology Conference, San Francisco, CA (October 14, 2003).

[4] GE Energy IGCC case based on data provided by GE Energy Gasification Technologies.

[5]IGCC cost and performance information taken from: EPRI, "Summary of Recent IGCC Studies of CO2 Capture for Sequestration, Presented at Gasification Technology Conference, San Francisco, CA (October 14, 2003). Shell questions the need for a spare gasifier with their technology. It remains to be seen whether initial commercial IGCC developers in the U.S. will require configurations with spare gasifiers or not. Without the spare gasifier the cost would be considerably lower. Shell also believes the Oir technology. It dry feed system is 50-70 percent of one of the slurry feed systems.

[6]Equals Overnight Capital Cost plus interest during construction. Interest during construction equals about 9% of Overnight Capital Cost for PC and IGCC (4 year construction).

[7]Calculated using EPRI TAG methodology (See Appendix A). Includes 10% Owner's Cost and assumes 4 year construction with equal annual investments.

Table 5-7. Cost of Energy Estimates for NGCC and PC Power Plants under Traditional Financing

	NGCC Reference ($4.50 gas; 50% CF; 50% Eff.)	NGCC 1 ($4.00 gas; 85% CF; 50% Eff.)	NGCC 2 ($4.50 gas; 85% CF; 50% Eff.)	NGCC 3 ($5.00 gas; 35% CF; 50% Eff.)	PC Reference ($1,200/kW; 85% CF; 39% Eff.)	PC 1 ($1,100/kW 85% CF; 38% Eff.)	PC 2 ($1,300/kW; 85% CF 39% Eff.)	PC 3 ($1,400/kW; 85% CF 40% Eff.)
Capital Costs								
Plant Size (MW)	**500**	500	500	500	**550**	550	550	550
Overnight Capital Cost ($/kW)	**$510**	$510	$510	$510	**$1,200**	$1,100	$1,300	$1,400
Total Plant Investment ($/kW)[1]	**$525**	$525	$525	$525	**$1,306**	$1,197	$1,415	$1,524
Operation								
Fuel cost ($/mmBtu)	**$4.50**	$4.00	$4.50	$5.50	**$1.25**	$1.25	$1.25	$1.25
Plant Efficiency (%)	**50%**	50%	50%	50%	**39%**	38%	39%	40%
Heat Rate (Btu/kWh HHV)	**6,800.00**	6,800	6,800	6,800	**8,700**	9,000	8,700	8,500
Plant Capacity Factor (%)	**50%**	85%	85%	35%	**85%**	85%	85%	85%
Annual Generation (MWh)	**2,190,000**	3,723,000	3,723,000	1,533,000	**4,095,300**	4,095,300	4,095,300	4,095,300
Long-term Financing								
Percentage Debt	**55%**	55%	55%	55%	**55%**	55%	55%	55%
Debt Interest Rate	**6.5%**	6.5%	6.5%	6.5%	**6.5%**	6.5%	6.5%	6.5%
Percent Equity	**45.0%**	45.0%	45.0%	45.0%	**45.0%**	45.0%	45.0%	45.0%
After tax Equity Return	**11.5%**	11.5%	11.5%	11.5%	**11.5%**	11.5%	11.5%	11.5%
Tax rate (Federal & State)	**38.2%**	38.2%	38.2%	38.2%	**38.2%**	38.2%	38.2%	38.2%
Pre-tax Equity Return	**18.6%**	18.6%	18.6%	18.6%	**18.6%**	18.6%	18.6%	18.6%
Pre-tax WACC	**11.9%**	11.9%	11.9%	11.9%	**11.9%**	11.9%	11.9%	11.9%
Levelized Carrying Charge[2]	**12.3%**	12.3%	12.3%	12.3%	**12.3%**	12.3%	12.3%	12.3%
Estimated Cost of Energy								
O&M (cent/kWh)	**0.25**	0.25	0.25	0.25	**0.80**	0.80	0.80	0.80
Fuel (cent/kWh)	**3.06**	2.72	3.06	3.74	**1.09**	1.13	1.09	1.06
Capital (cent/kWh)	**1.47**	0.87	0.86	2.10	**2.16**	1.98	2.34	2.52
Cost of Energy (cent/kWh)	**4.8**	3.84	4.17	6.09	**4.0**	3.90	4.22	4.38

[1]Equals Overnight Capital Cost plus interest during construction. Interest during construction equals 4.4% of overnight capital cost for NGCC (2 yr construction) and 14% of Overnight Capital Cost for PC and IGCC (4 year construction).

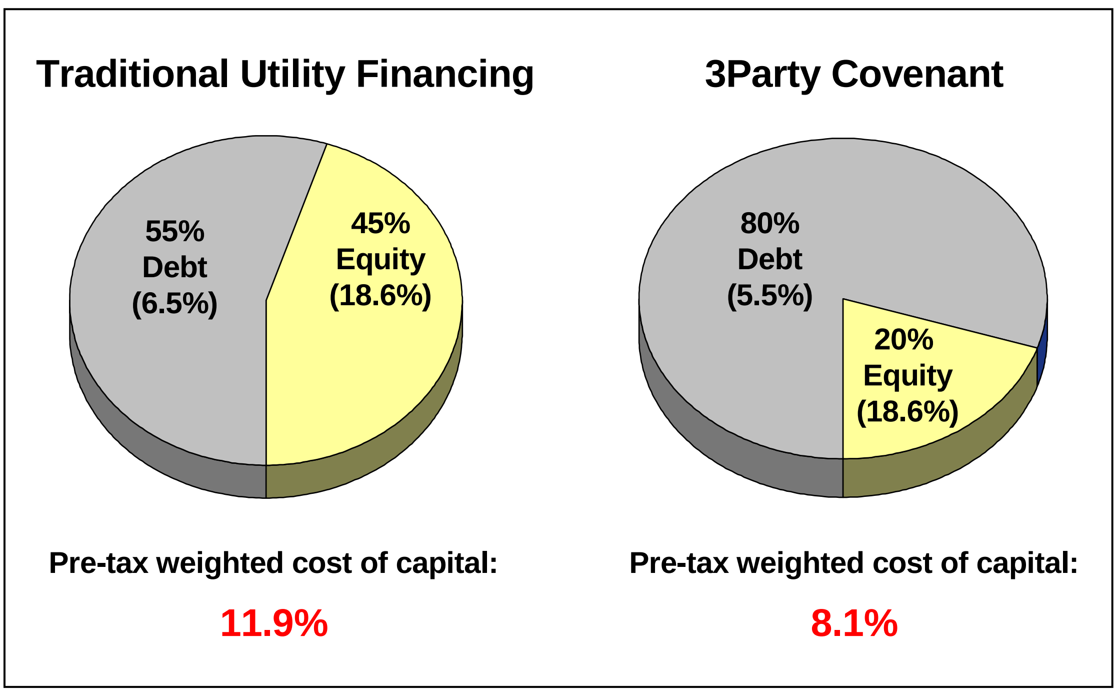
[2]Calculated using EPRI TAG methodology (See Appendix A). Includes 10% Owner's Cost and assumes 4 yr PC construction and 2 yr NGCC construction with equal annual investments.

5.5. 3Party Covenant Cost of Energy Impact

A primary benefit of the 3Party Covenant is that it significantly reduces Cost of Capital. The lower financing costs, in turn, reduce the cost of energy from an IGCC power plant about 17 percent. The cost of energy reductions result from:

1. Providing for a significantly higher ratio of debt to equity than a traditional utility financing ratio (from 55/45 to 80/20 under the 3Party Covenant). The higher ratio results in the replacement of 18.6 percent pre-tax equity (assuming an allowed after-tax return of 11.5 percent and 38.2 percent federal and state combined tax rate) with 5.5 percent federal debt for 25 percent of Total Plant Investment.[156]
2. Lowering the cost of debt through the federal loan guarantee, which reduces the interest charge from a typical 6.5 percent for a mid-grade utility bond in January 2004 to the 5.5 percent rate associated with a federal agency bond (essentially a ¾ to1 percent reduction in the cost of long-term debt).
3. Funding construction financing costs during the construction (adding Construction Work in Progress (CWIP) to the rate base), rather than accruing

Figure 5-1. Cost of Capital Reduction under 3Party Covenant



[156] In November 2003, the Wisconsin Public Utility Commission approved construction of two PC plants with a 45/55 debt to equity ratio and a 12.7 percent after-tax equity return.

these costs, which typically account for 10-15 percent of Overnight Capital Costs, by allowing them to be added to the rate base as incurred.

As illustrated in Figure 5-1, these changes reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant from about 12 percent under traditional utility financing to 8 percent under the 3Party Covenant. Since the cost of capital accounts for over 60% of the total cost of energy in a capital intensive coal based PC or IGCC, this change in cost of capital (along with the reduction in construction financing costs) reduces the total energy cost about 17 percent. These results are demonstrated in Table 5-8 which illustrates the cost of energy impact of the 3Party Covenant for each of the IGCC plants shown in Table 5-6 above. As illustrated in Table 5-8, the 3Party Covenant reduces the cost of energy of the reference IGCC plant from 4.40 cents/kWh (44.0 $/MWh) to 3.65 cents/kWh (36.5 $/MWh), which is a 17 percent reduction.

Table 5-8. Cost of Energy Estimates for IGCC Power Plants under 3Party Covenant

	IGCC Reference[1] (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)	IGCC 1[2] (2+1 gasifiers, $1,200/kW; 85% CF 42% Eff.)	IGCC 2[2] (2+1 gasifiers, $1,400/kW; 75% CF; 39% Eff.)	IGCC 3[2] (2+1 gasifiers, $1,600/kW; 85% CF; 39% Eff.)	IGCC 4[3] ConocoPhil (2+1 gasifiers)	IGCC 5[3] GE Energy Q (2+1 gasifiers)	IGCC 6[4] Data from GE Energy (2+1 gasifiers)	IGCC 7[5] Shell (2+1 gasifiers)
Design and Construction								
Plant Size (MW)	**550**	550	550	550	550	550	564.9	550
Overnight Capital Cost ($/kW)	**$1,400**	$1,200	$1,400	$1,600	$1,300	$1,270	$1,367	$1,620
Total Plant Investment ($/KW)[6]	**$1,400**	$1,200	$1,400	$1,600	$1,300	$1,270	$1,367	$1,620
Operation								
Fuel cost ($/mmBtu)	**$1.25**	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25	$1.25
Plant Efficiency (%)	**39%**	42%	39%	39%	40%	36%	39.1%	41%
Heat Rate (Btu/kWh HHV)	**8,700.00**	8,200.00	8,700.00	8,700.00	8,550.00	9,450.00	8,717	8,370.00
Plant Capacity Factor (%)	**85%**	85%	75%	85%	85%	85%	85%	85%
Annual Generation (MWh)	**4,095,300**	4,095,300	3,613,500	4,095,300	4,095,300	4,095,300	4,206,245	4,095,300
Financing								
Percentage Debt	**80%**	80%	80%	80%	80%	80%	80%	80%
Debt Interest Rate	**5.5%**	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Percent Equity	**20.0%**	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
After tax Equity Return	**11.5%**	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%
Tax rate (Federal & State)	**38.2%**	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%
Pre-tax Equity Return	**18.6%**	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%	18.6%
Pre-tax nominal WACC	**8.1%**	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
Levelized Carrying Charge[7]	**9.4%**	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%
Estimated Cost of Energy								
O&M (cent/kWh)	**0.80**	0.80	0.80	0.80	0.80	0.80	0.69	0.80
Fuel (cent/kWh)	**1.09**	1.025	1.09	1.09	1.07	1.18	1.09	1.05
Capital (cent/kWh)	**1.76**	1.51	2.00	2.02	1.64	1.60	1.72	2.04
Cost of Energy (cent/kWh)	**3.65**	3.34	3.89	3.90	3.51	3.58	3.50	3.89
Comparison to Cost of Energy under Traditional Financing								
Cost of Energy (cent/kWh) under Traditional Financing	**4.4**	**4.0**	**4.7**	**4.8**	**4.2**	**4.3**	**4.2**	**4.8**
Percent Reduction under 3Party Covenant	**17%**	**16%**	**18%**	**18%**	**17%**	**16%**	**17%**	**18%**

[1]Reference case developed by authors to illustrate representative generic IGCC plant.

[2A]lternative generic IGCC cases developed by authors assuming a spare gasifier.

[3]IGCC cost and performance information taken from: EPRI, "Summary of Recent IGCC Studies of CO2 Capture for Sequestration, Presented at Gasification Technology Conference, San Francisco, CA (October 14, 2003).

[4] GE Energy IGCC case based on data provided by GE Energy Gasification Technologies.

[5]IGCC cost and performance information taken from: EPRI, "Summary of Recent IGCC Studies of CO2 Capture for Sequestration, Presented at Gasification Technology Conference, San Francisco, CA (October 14, 2003). Shell questions the need for a spare gasifier with their technology. It remains to be seen whether initial commercial IGCC developers in the U.S. will require configurations with spare gasifiers or not. Without the spare gasifier, the cost would be considerably lower. Shell also believes the r technology. It r dry feed system is 50-70 percent of one of the slurry feed systems.

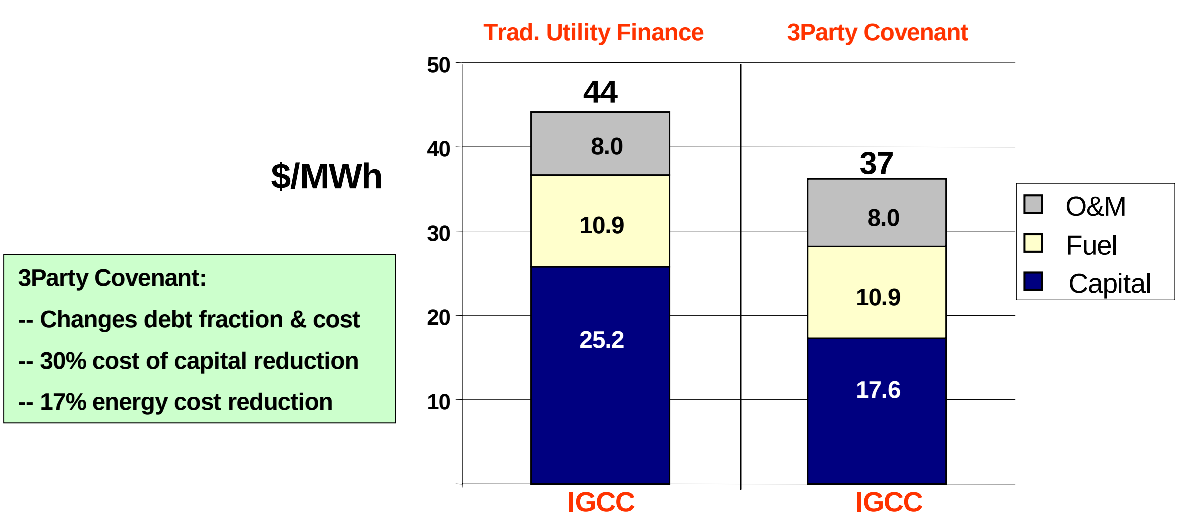
[6]Equals Overnight Capital Cost plus interest during construction. No interest during construction accrues in the 3Party Covenant case due to CWIP.

[6]Calculated using EPRI TAG methodology (See Appendix A). Includes 10% Owner's Cost and Construction Financing Costs, assuming 4 year construction with equal annual investments.

Figure 5-2 illustrates the impact of the 3Party Covenant graphically by comparing the cost of energy associated with the Reference IGCC plant financed under a traditional utility financing scenario compared with the same plant financed under the 3Party Covenant. As is illustrated, the 3Party Covenant reduces the cost of capital component of energy costs from 25.2 $/MWh to 17.6 $/MWh, which is a 30 percent reduction. As a result, the reference IGCC plant financed under traditional utility financing has a calculated cost of energy of 44 $/MWh, while the same plant financed under the 3Party Covenant has a cost of energy of 37 $/MWh. The 3Party Covenant reduces the cost of capital component of energy cost approximately 30 percent and energy cost 17 percent.

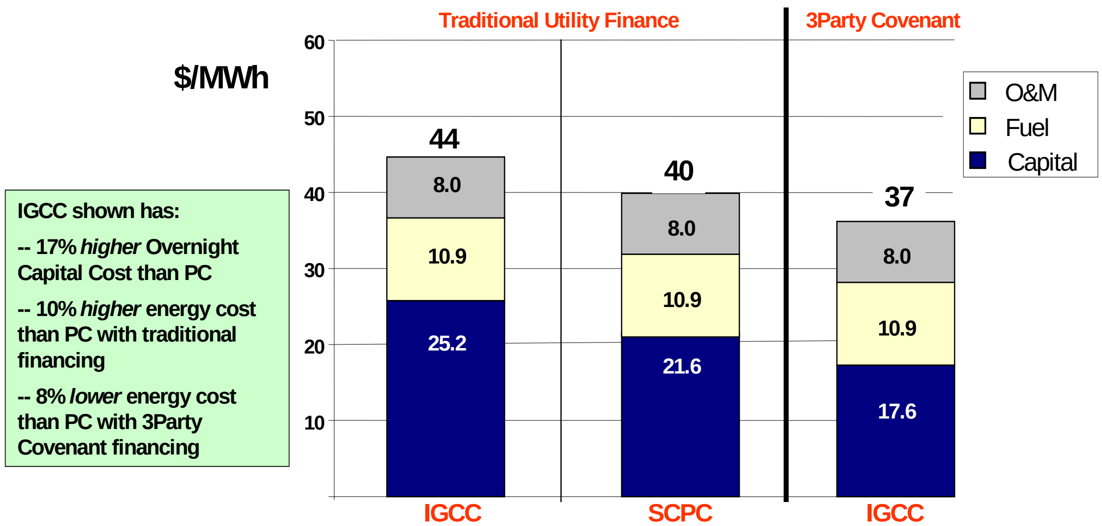
Figure 5-3 illustrates how the 3Party Covenant affects the relative cost of energy of IGCC compared to PC. The figure illustrates the Reference IGCC plant assuming traditional utility financing and under the 3Party Covenant compared to a PC plant built with traditional utility financing. Figure 5-3 illustrates that the Reference IGCC plant has a 17 percent higher Overnight Capital (or EPC) cost than the PC plant, which results in a 10 percent higher cost of energy when both are financed traditionally. However, when 3Party Covenant financing is applied to the IGCC plant, its cost of energy is reduced to a level 8 percent below the PC plant.

Figure 5-2. 3Party Covenant Impact on IGCC Cost of Energy



Overnight Capital Cost ($/kW)	$1,400	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25
Capacity Factor	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700
Debt Fraction	55%	**80%**
Debt Cost	6.5%	**5.5%**
Pre-Tax Equity Return	18.6%	18.6%

Figure 5-3. IGCC Cost of Energy versus Super-Critical PC



Overnight Capital Cost ($/kW)	$1,400	$1,200	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25	$1.25
Capacity Factor	85%	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700	8,700
Debt Fraction	55%	55%	80%
Debt Cost	6.5%	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%	18.6%

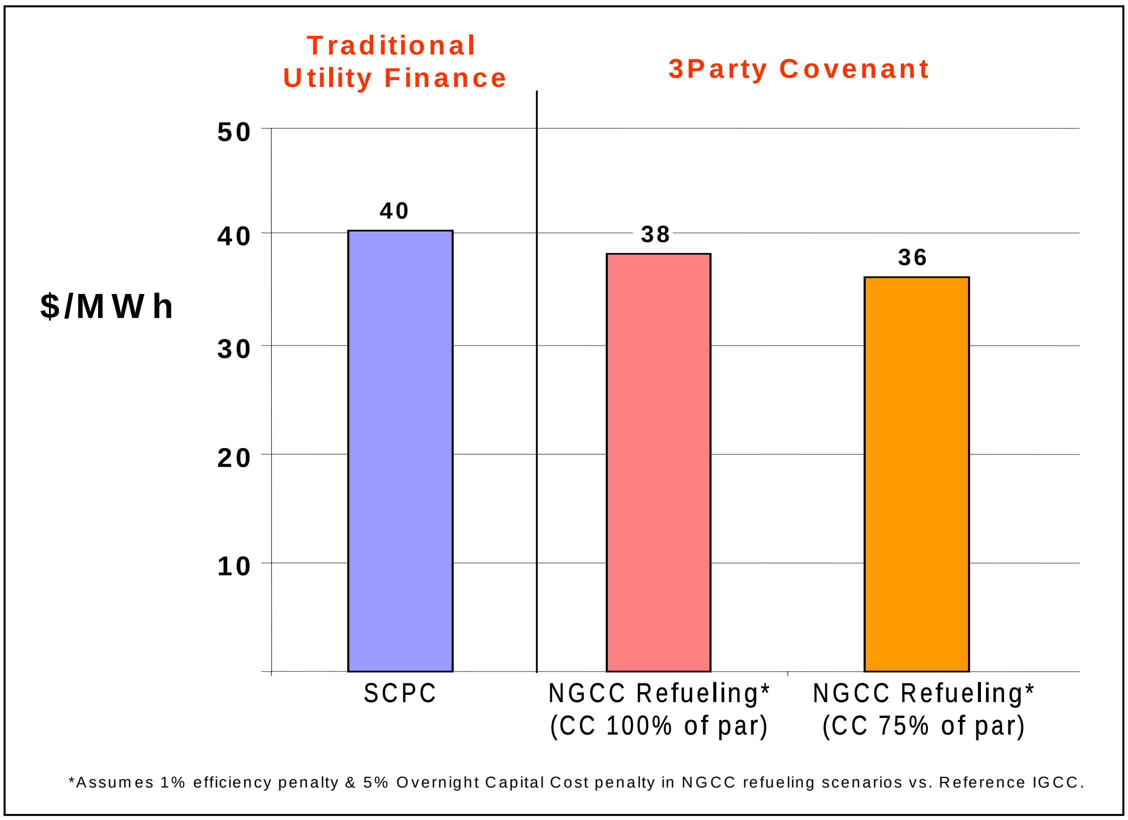
5.6. 3Party Covenant Cost of Energy for NGCC Refueling Scenarios

As discussed in Section 3.4 above, there may be opportunities to create favorable IGCC economics by refueling distressed NGCC assets with coal gasification systems. Under the Reference case IGCC, it is assumed that the gasifier island accounts for about 65 percent of the $1,400/kW Overnight Capital Cost, or roughly $900/kW and that the combined cycle power block accounts for 35 percent of the Overnight Capital Cost, or about $500/kW. If available for refueling at 75 percent of par, the cost is reduced to about $375/kW, and at 50 percent of par, it is reduced to $250/kW. If these costs are applied as the combined cycle power block component of the IGCC EPC cost, the Overnight Capital Cost is reduced to $1,275/kW and $1,150/kW, respectively (well below the $1,400/kW reference case assumption).

In refueling scenarios, there is likely to be some inefficiency in design and construction of the gasification system and its integration due to retrofit requirements. For example, a $15/kW cost has been suggested for refitting the combustion turbine. Other costs might include the need for supplemental steam generation or site improvements. In addition, plant integration may be less than is achieved at a facility designed originally to be an IGCC, which may result in reduced efficiency. For this analysis, a 5 percent capital cost and 1 percent efficiency penalty is incorporated into the NGCC refueling scenarios to address these issues.

Figure 5-4 illustrates the cost of energy achieved in NGCC refueling scenarios assuming the combined cycle power block was contributed to the project at 75 percent of its original par value (assumed to be $500/kW). Figure 5-4 illustrates that combining 3Party Covenant financing and the potential cost savings associated with using existing distressed NGCC assets produces energy at levels below an all-new IGCC and at levels 10 percent below the reference PC plant built with tradition utility financing. Actual project savings will depend on the cost of the distressed asset to the project and the level of additional cost associated with retrofitting the combined cycle power block to work with a coal gasification system.

Figure 5-4. Cost of Energy of NGCC Refueling under 3Party Covenant



APPENDIX A. COMPONENTS OF FEDERAL LEGISLATION FOR IMPLEMENTING 3PARTY COVENANT

Implementation of the 3Party Covenant requires federal legislation authorizing loan guarantees for qualifying IGCC projects. Consideration must be given to a number of implementation issues in developing legislation to ensure the program meets IGCC deployment objectives with minimal federal budget impact. Meeting deployment objectives will require determining the desired level of investment (in what timeframe), and ensuring that the economic and financial hurdles that have inhibited IGCC commercial deployment to date are adequately addressed.

The outline below describes recommended components of federal legislation to implement the 3Party Covenant. These components are designed to stimulate development of 3,500 MW of IGCC generation with federal loan guarantees of $5 billion. The program is targeted at stimulating deployment of IGCC technology, which is the focus of this paper. This or other incentive programs may be appropriate for IGCC and other advanced coal technologies.

<u>Purpose</u>

Establish a federal loan guarantee program that stimulates deployment of IGCC by reducing cost of capital, apportioning risk, and assisting with pre-development costs in order to:

- Support U.S. energy independence
- Promote homeland security
- Improve coal generation environmental performance
- Increase generation efficiency
- Refuel and revalue billions of dollars of financially distressed and underutilized natural gas combined cycle investments
- Reduce pressure on natural gas prices
- Provide affordable and reliable electricity supplies
- Position the U.S. as a global leader in advanced coal generation technology
- Minimize the burden to the federal budget

<u>Scope</u>

- $500 million appropriations to score up to $5 billion of federal loan guarantees for 3,500 MWs of base load capacity:
    - $450 million for scoring loan guarantees
    - $50 million revolving fund for pre-development engineering loans
    - Loan guarantees may be committed for a period of 10 years beginning with the first fiscal year the program is funded.

- Program shall be implemented through an accelerated rulemaking process to be completed within 12 months of enactment
- Program shall authorize the collection of application or other fees to cover administrative costs as well as insurance fees to the extent such fees are determined to be appropriate by the Secretary

<u>Loan Guarantees</u>

- Up to 80% of total plant Investment
- 30-year term, non-recourse, backed by full faith and credit of U.S. Government
- Owner contributes 20% equity investment

<u>Qualifying Projects</u>

- An IGCC or other coal-fueled power plant technology with the following performance characteristics:
  - Coal accounts for at least 75% of fuel heat input
  - In the case of IGCC, combustion turbine operates on syngas as primary fuel (natural gas or diesel may serve as an emergency back-up fuel only)
  - Design heat rate of 8,700 btu/kWh (HHV) or lower
  - New power plant, repowering of an existing coal power plant, or refueling of an existing natural gas combined cycle power plant
- Emissions Performance:
  - 99% sulfur reduction with SO_2 emission not to exceed 0.04 lb/mmBtu
  - NOx emissions not to exceed 0.025 lb/mmBtu
  - Particulate emissions from stack not to exceed 0.01 lb/mmBtu
  - 95% mercury emissions control
- Determination by DOE that the technology provides a technical pathway for CO_2 separation and capture and for the co-production of hydrogen slip-streams.
- To minimize federal budget scoring, qualifying projects shall have:
  - 3Party Covenant assured revenue stream through state PUC or other regulatory body providing upfront and ongoing regulatory determinations of prudence of project costs and approvals of pass-through of project costs (reflecting ongoing inclusion of approved capital investments in rate base and inclusion of approved operating costs in the cost of service, or reflecting purchased power costs incurred under a power purchase agreement) under federal and state enabling laws (“Regulatory Determinations”); or
  - Comparable credit (and budget scoring) as that provided by 3Party Covenant Regulatory Determinations, which might be created through insurance, industrial guarantees, or other credit enhancements.
- Projects shall include EPC contractor performance and delivery guarantees (full wrap) for project construction.

- Initial financing shall provide Line of Credit for additional draw of up to 15 percent of Capital Costs with an additional minimum matching equity contribution of 20 percent of the amount drawn.
- Secretary shall issue guarantees only for projects with budget scoring that does not exceed 10% of loan principal.
- Secretary shall develop criteria for issuing loan guarantee reservations (commitments prior to closing) for projects that have demonstrated feasibility and meet program qualifications

Pre-development Engineering Loans

- Non-recourse, interest-free loans shall be available for 75% of the cost of developing initial engineering and feasibility evaluations of potential projects
- Developer will be required to provide 25% cash match
- Loans not to exceed $5 million dollars
- Loans to be repaid out of long-term project loan disbursements and placed into a revolving loan fund
- Secretary shall develop criteria for selecting projects to receive Pre-development Engineering Loans, taking into account project timing, feasibility and ability to meet Project Selection Criteria (below)

Project Selection

- Secretary shall establish Project Selection Criteria, including consideration of the following elements:
    - Utilization of diverse coal supplies and types
    - Competitive electricity prices
    - Geographic diversity
    - Project feasibility
    - Financial strength of project
    - Environmental performance

APPENDIX B: LEVELIZED CARRYING CHARGE CALCULATIONS

Levelized Carrying Charge--Traditional Utility Financing of Coal Plant (MACRS for depreciation)

inflation rate	0.02
Nominal cost of debt	0.065
Real cost of debt	0.04411765
Nominal cost of equity	0.115
Real cost of equity	0.09313725
debt fraction	0.55
equity fraction	0.45
federal/state income tax rate	0.382
Weighted pretax cost of capital	0.06617647
Weighted after tax cost of capital	0.05690735
Discount rate	0.05690735
Construction period (years)	4
Number of equal invest payments	4
PTI rate	0.02
Book life (years)	30
Tax life (years)	20
CRF for levelizing CCR	0.07026126
Y	0.98039216
Z	1.05690735
TCE/TPI	0.89190721
TPI/TPC	1.0886
Owner cost as fraction of TPI	0.09185726
Owner cost as fraction of TPC	0.1
Modified Accelerated Capital Recovery System (MACRS)	

Year of operation	PV factor	Tax Deprec	Book Deprec	Deferred income tx	Remaining book value	Return on equity	Return on debt	Taxes paid	PTI	CCR	PV of CCR
1	0.946157	0.065625	0.033333	0.0117354	1	0.045762	0.0264936	0.017553	0.017838	0.152715	0.144493
2	0.895213	0.070078	0.033333	0.0133537	0.966667	0.044516	0.0256848	0.015165	0.017838	0.14989	0.134184
3	0.847011	0.064822	0.033333	0.01144358	0.933333	0.04327	0.0248759	0.016305	0.017838	0.147065	0.124566
4	0.801406	0.059961	0.033333	0.009677	0.9	0.042024	0.0240671	0.017301	0.017838	0.14424	0.115595
5	0.758255	0.055464	0.033333	0.0080427	0.866667	0.040777	0.0232583	0.018165	0.017838	0.141415	0.107229
6	0.717428	0.051304	0.033333	0.00653088	0.833333	0.039531	0.0224495	0.018907	0.017838	0.13859	0.099428
7	0.6788	0.047456	0.033333	0.00513244	0.8	0.038285	0.0216407	0.019535	0.017838	0.135765	0.092157
8	0.642251	0.044594	0.033333	0.00409234	0.766667	0.037039	0.0208318	0.019805	0.017838	0.13294	0.085381
9	0.60767	0.044594	0.033333	0.00409234	0.733333	0.035793	0.020023	0.019035	0.017838	0.130115	0.079067
10	0.574951	0.044594	0.033333	0.00409234	0.7	0.034547	0.0192142	0.018264	0.017838	0.12729	0.073185
11	0.543994	0.044594	0.033333	0.00409234	0.666667	0.033301	0.0184054	0.017494	0.017838	0.124464	0.067708
12	0.514703	0.044594	0.033333	0.00409234	0.633333	0.032055	0.0175965	0.016724	0.017838	0.121639	0.062608
13	0.48699	0.044594	0.033333	0.00409234	0.6	0.030809	0.0167877	0.015954	0.017838	0.118814	0.057861
14	0.460769	0.044594	0.033333	0.00409234	0.566667	0.029563	0.0159789	0.015183	0.017838	0.115989	0.053444
15	0.43596	0.044594	0.033333	0.00409234	0.533333	0.028317	0.0151701	0.014413	0.017838	0.113164	0.049335
16	0.412486	0.044594	0.033333	0.00409234	0.5	0.027071	0.0143612	0.013643	0.017838	0.110339	0.045513
17	0.390276	0.044594	0.033333	0.00409234	0.466667	0.025825	0.0135524	0.012873	0.017838	0.107514	0.04196
18	0.369263	0.044594	0.033333	0.00409234	0.433333	0.024579	0.0127436	0.012103	0.017838	0.104689	0.038658
19	0.34938	0.044594	0.033333	0.00409234	0.4	0.023333	0.0119348	0.011332	0.017838	0.101864	0.035589
20	0.330569	0.005574	0.033333	-0.0100883	0.366667	0.022087	0.0111259	0.024743	0.017838	0.099039	0.032739
21	0.31277	0	0.033333	-0.012114	0.333333	0.020841	0.0103171	0.025998	0.017838	0.096214	0.030093
22	0.295929	0	0.033333	-0.012114	0.3	0.019595	0.0095083	0.025228	0.017838	0.093389	0.027636
23	0.279995	0	0.033333	-0.012114	0.266667	0.018349	0.0086995	0.024458	0.017838	0.090564	0.025357
24	0.26492	0	0.033333	-0.012114	0.233333	0.017103	0.0078907	0.023688	0.017838	0.087738	0.023244
25	0.250655	0	0.033333	-0.012114	0.2	0.015857	0.0070818	0.022917	0.017838	0.084913	0.021284
26	0.237159	0	0.033333	-0.012114	0.166667	0.01461	0.006273	0.022147	0.017838	0.082088	0.019468
27	0.22439	0	0.033333	-0.012114	0.133333	0.013364	0.0054642	0.021377	0.017838	0.079263	0.017786
28	0.212308	0	0.033333	-0.012114	0.1	0.012118	0.0046554	0.020607	0.017838	0.076438	0.016228
29	0.200877	0	0.033333	-0.012114	0.066667	0.010872	0.0038465	0.019837	0.017838	0.073613	0.014787
30	0.190061	0	0.033333	-0.012114	0.033333	0.009626	0.0030377	0.019066	0.017838	0.070788	0.013454
Present value of CCRn											1.750037
Levelized CCR											**0.123**

Levelized Carrying Charge -- 3Party Covenant Financing (MACRS for depreciation)

inflation rate	0.02
Nominal cost of debt	0.055
Real cost of debt	0.03431373
Nominal cost of equity	0.115
Real cost of equity	0.09313725
debt fraction	0.8
equity fraction	0.2
federal/state income tax rate	0.382
Weighted pretax cost of capital	0.04607843
Weighted after tax cost of capital	0.03559216
Discount rate	0.03559216
Construction period (years)	1
Number of equal invest payments	1
PTI rate	0.02
Book life (years)	30
Tax life (years)	20
CRF for levelizing CCR	0.05477546
Y	0.98039216
Z	1.03559216
TCE/TPI	1
TPI/TPC	1
Owner cost as fraction of TPI	0.1
Owner cost as fraction of TPC	0.1
Modified Accelerated Capital Recovery System (MACRS)	

Year of operation	PV factor	Tax Deprec	Book Deprec	Deferred income tx	Remaining book value	Return on equity	Return on debt	Taxes paid	PTI	CCR	PV of CCR
1	0.965631	0.065625	0.033333	0.01233542	1	0.0204902	0.030196	0.00033	0.02	0.116685	0.11267473
2	0.932443	0.070078	0.033333	0.01403646	0.966667	0.0198693	0.029281	-0.00175	0.02	0.114765	0.10701217
3	0.900396	0.064822	0.033333	0.01202867	0.933333	0.0192484	0.028366	-0.00013	0.02	0.112846	0.10160574
4	0.869451	0.059961	0.033333	0.01017177	0.9	0.0186275	0.027451	0.001342	0.02	0.110926	0.09644454
5	0.839569	0.055464	0.033333	0.00845391	0.866667	0.0180065	0.026536	0.002676	0.02	0.109006	0.09151808
6	0.810714	0.051304	0.033333	0.00686479	0.833333	0.0173856	0.025621	0.003882	0.02	0.107086	0.08681634
7	0.78285	0.047456	0.033333	0.00539486	0.8	0.0167647	0.024706	0.004968	0.02	0.105167	0.08232968
8	0.755945	0.044594	0.033333	0.00430157	0.766667	0.0161438	0.023791	0.005677	0.02	0.103247	0.07804888
9	0.729964	0.044594	0.033333	0.00430157	0.733333	0.0155229	0.022876	0.005293	0.02	0.101327	0.07396508
10	0.704876	0.044594	0.033333	0.00430157	0.7	0.014902	0.021961	0.00491	0.02	0.099407	0.0700698
11	0.68065	0.044594	0.033333	0.00430157	0.666667	0.014281	0.021046	0.004526	0.02	0.097488	0.0663549
12	0.657257	0.044594	0.033333	0.00430157	0.633333	0.0136601	0.020131	0.004142	0.02	0.095568	0.06281258
13	0.634667	0.044594	0.033333	0.00430157	0.6	0.0130392	0.019216	0.003758	0.02	0.093648	0.05943538
14	0.612855	0.044594	0.033333	0.00430157	0.566667	0.0124183	0.018301	0.003374	0.02	0.091728	0.05621613
15	0.591791	0.044594	0.033333	0.00430157	0.533333	0.0117974	0.017386	0.002991	0.02	0.089809	0.05314795
16	0.571452	0.044594	0.033333	0.00430157	0.5	0.0111765	0.016471	0.002607	0.02	0.087889	0.05022427
17	0.551812	0.044594	0.033333	0.00430157	0.466667	0.0105556	0.015556	0.002223	0.02	0.085969	0.04743877
18	0.532847	0.044594	0.033333	0.00430157	0.433333	0.0099346	0.014641	0.001839	0.02	0.084049	0.04478542
19	0.514534	0.044594	0.033333	0.00430157	0.4	0.0093137	0.013725	0.001455	0.02	0.08213	0.04225842
20	0.49685	0.005574	0.033333	-0.0106041	0.366667	0.0086928	0.01281	0.015977	0.02	0.08021	0.03985222
21	0.479773	0	0.033333	-0.0127333	0.333333	0.0080719	0.011895	0.017723	0.02	0.07829	0.0375615
22	0.463284	0	0.033333	-0.0127333	0.3	0.007451	0.01098	0.017339	0.02	0.07637	0.03538116
23	0.447362	0	0.033333	-0.0127333	0.266667	0.0068301	0.010065	0.016955	0.02	0.074451	0.03330633
24	0.431986	0	0.033333	-0.0127333	0.233333	0.0062092	0.00915	0.016571	0.02	0.072531	0.03133232
25	0.417139	0	0.033333	-0.0127333	0.2	0.0055882	0.008235	0.016188	0.02	0.070611	0.02945466
26	0.402803	0	0.033333	-0.0127333	0.166667	0.0049673	0.00732	0.015804	0.02	0.068691	0.02766906
27	0.388959	0	0.033333	-0.0127333	0.133333	0.0043464	0.006405	0.01542	0.02	0.066772	0.0259714
28	0.375591	0	0.033333	-0.0127333	0.1	0.0037255	0.00549	0.015036	0.02	0.064852	0.02435775
29	0.362682	0	0.033333	-0.0127333	0.066667	0.0031046	0.004575	0.014652	0.02	0.062932	0.02282434
30	0.350217	0	0.033333	-0.0127333	0.033333	0.0024837	0.00366	0.014269	0.02	0.061012	0.02136757
Present value of CCRn											1.71223719
Levelized CCR											**0.094**

Revenue Requirements for Regulated Electric Utilities
(EPRI methodology)

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15 April 2004

Derivation of Carrying Charge Formula

The following is based on the EPRI *Technical Assessment Guide* (1993), for the cases where the investment tax credit ITC = 0. In any year the revenue requirement is
R = FOM + CR + RE + RD + TP + PTI = CC + FOM, where
R = revenue
CC = carrying charge
FOM = fuel and operation and maintenance (O&M) costs
CR = capital recovery
RE = return on equity
RD = return on debt (deductible for tax purposes)
TP = federal and state income taxes paid = t*(R – FOM – RD - PTI – DT)
PTI = property taxes and insurance
t = income tax rate (assumed to be 0.382)
DT = depreciation for tax purposes [generally different from book depreciation (DB)]
Thus:
R = FOM + CR + RE + RD + PTI + t*(R – FOM – PTI - RD – DT)
Simple algebraic manipulations yield:
(1 – t)*(R – FOM – RD – PTI) = RE + CR – t*DT,
R = FOM + RD + PTI + (RE + CR)/(1 – t) – [t/(1 – t)]*DT,
R - FOM - RD - PTI = (RE + CR)/(1 – t) – [t/(1 – t)]*DT,
TP = t*[(RE + CR)/(1 – t) – t/(1 – t)*DT – DT] = [t/(1 – t)]*(RE + CR – DT),
so that the carrying charge is:

CC = [1/(1 – t)]*(RE + CR) + RD - t*DT/(1 – t) + PTI

Alternatively, one can write:

CC = CR + RE + RD + TP + PTI where **TP = [t/(1 – t)]*(RE + CR – DT)**

Reference year $ = December of the year prior to start-up on following January 1
N = construction time (years)
BL = book life (years)
TL = tax life (years)
Costs assumed to be incurred at end of year
TPC = total plant cost (overnight construction cost) = SUM(E_1:E_N)
E_n = construction cost incurred in year n, expressed in December reference year $
TCE = total cash expended in mixed year $ = SUM[$E_1/(1+i)^{N-1}$:E_N] [= TPC if no inflation (i = 0)]
i = inflation rate
TPI = total plant investment in December reference year $ = SUM{$E_1[(1+c)/(1+i)]^{N-1}$:E_N}

AFUDC = allowance for funds used during construction = TPI – TCE
= SUM{$E_1[(1+c)/(1+i)]^{N-1}$ - $E_1/(1+i)^{N-1}$: E_N - E_N}
DF = debt share of investment (DF of AFUDC is tax deductible)
EF = equity share of investment (EF of AFUDC is non-depreciating for book/tax purposes
d = cost of debt
e = cost of equity
c = weighted cost of capital = DF*d + EF*e
IGD = investment gross depreciable = TCE + DF*AFUDC
IND = investment non-depreciable = owner costs + AFUDC*EF
Owner costs (prepaid royalties, startup costs, inventory capital, initial costs for catalysts and chemicals, and land) are treated as a non-depreciating asset
IT = investment total = IGD + IND = TCE + AFUDC + owner costs
= TPI + owner costs [= IN (investment net) if ITC = 0)]
PTI = property taxes and insurance = pti*TCE
pti = PTI rate (assumed to be 0.02—note that with zero inflation, pti multiplies TPC, not TPI)
DB = book depreciation = IGD/BL

Calculation of individual components

CR (capital recovery) = (IGD)/BL + EF*AFUDC/BL (equity AFUDC recovery)
+ DIT (deferred income tax)
CR = (TCE + DF*AFUDC)/BL + EF*AFUDC/BL + DIT
CR = (TCE + AFUDC)/BL + DIT
CR = TPI/BL + DIT = DB + DIT

Book Depreciation

DB = book depreciation = TPI/BL

DB/TPI = 1/BL

Deferred Income Taxes

DIT_n = t*(TDR_n – 1/BL)*IGD = t*(TDR_n – 1/BL)*(TCE + DF*AFUDC)
= t*(TDR_n – 1/BL)*[TCE + DF*(TPI – TCE)]
TDR_n = Tax depreciation rate for year n
DIT_n/TPI = t*(TDR_n – 1/BL)*[TCE/TPI + DF*(1 – TCE/TPI)]

DIT_n/TPI = t*(TDR_n – 1/BL)*[DF + TCE/TPI*(1 – DF)]

Return on Equity

RE_n = e*[equity balance in year n (note: EF*AFUDC does not depreciate)]
= e*EF*{owner costs + AFUDC + TCE*[1 – (n-1)/BL]}
= e*EF*{owner costs + TPI - TCE + TCE*[1 – (n-1)/BL]}
= e*EF*[owner costs + TPI – TCE*(n-1)/BL]

RE_n/TPI = e*EF*[(owner costs/TPI) + 1 – (TCE/TPI)*(n-1)/BL]

Return on Debt

RD_n = d*(debt balance in year n)
= d*DF*{owner costs + (TCE + AFUDC)*[1 – (n-1)/BL]}
= d*DF*{owner costs + (TPI)*[1 – (n-1)/BL]}

$$\mathbf{RD_n/TPI = d*DF*[(owner\ costs)/TPI + 1 - (n-1)/BL]}$$

Income Taxes Paid

TP_n = [t/(1–t)]*{e*EF*[owner costs + TPI – TCE*(n-1)/BL] + TPI/BL
+ [TCE+DF*(TPI– TCE)]*[t*(TDR_n–1/BL) – TDR_n]},

$$\mathbf{TP_n/TPI = [t/(1-t)]*\{e*EF*[(owner\ cost)/TPI + 1 - TCE/TPI*(n-1)/BL] + 1/BL}$$
$$\mathbf{+ [TCE/TPI + DF*(1 - TCE/TPI)]*[t*(TDR_n - 1/BL) - TDR_n]\}}$$

Property Taxes and Insurance

PTI = property taxes and insurance = pti*TCE

$$\mathbf{PTI/TPI = pti*(TCE/TPI)}$$

Simplified Representation of TCE/TPI

A simplification for TCE/TPI arises if it is assumed that there are N years of construction and M equal capital cost payments during this period, with the last payment made at the time of plant startup. Thus:

$$E_i = TPC/M, \text{ and}$$

TPI = (TPC/M)*(1 + Z + Z^2 + … + Z^{M-1}) = (TPC/M)*(Z^M - 1)/(Z – 1) where Z = $[(1 + c)/(1 + i)]^{N/M}$

$$TPI/TPC = (Z^M - 1)/[M*(Z - 1)]$$

Likewise

$$TCE = (TPC/M) = (TPC/M)*(Y^M - 1)/(Y - 1) \text{ where } Y = [1/(1 + i)]^{N/M}$$

so that

$$\mathbf{TCE/TPI = [(Y^M - 1)/(Y - 1)]/[(Z^M - 1)/(Z - 1)]}$$

Converting Annual Carrying Charge Rates into a Levelized Carrying Charge Rate

To convert the annual carrying charge rates:

CCR_n
= 1/BL + t*(TDR_n – 1/BL)*[DF + TCE/TPI*(1 – DF)]
+ e*EF*[(owner costs/TPI) + 1 – (TCE/TPI)*(n-1)/BL]
+ d*DF*[(owner costs)/TPI + 1 – (n-1)/BL]}
+ [t/(1–t)]*{e*EF*[(owner costs)/TPI + 1 – TCE/TPI*(n-1)/BL] + 1/BL
+ [TCE/TPI +DF*(1– TCE/TPI)]*[t*(TDR_n–1/BL) - TDR_n]}
+ pti*(TCE/TPI)

into a levelized capital charge rate LCCR (the multiplier of TPI), the present value at the time of plant startup of all CCR_n is summed over all years up through n = BL, and the resultant PV{CCR_n}) is converted into LCCR by multiplying by the capital recovery factor calculated for the discount rate dr and term BL:

$$\mathbf{LCCR = CRF\ (dr, BL)^*\ PV\{CCR_n\},\ where\ CRF\ (dr, BL) = dr/[1 - (1 + dr)^{-BL}]}$$

The discount used in this calculation is assumed to be the after-tax weighted cost of capital:

$$\mathbf{dr = DF^*d^*(1 - t) + EF^*e}$$