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FINANCING IGCC – 3 PARTY COVENANT

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

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EXECUTIVE SUMMARY

This paper describes a 3Party Covenant financing and regulatory program aimed at reducing financing costs and providing a risk-tolerant investment structure to stimulate initial deployment of five to ten Integrated Gasification Combined Cycle (IGCC) coal generation power plants during this decade. The 3Party Covenant is an arrangement between the federal government, state Public Utility Commission (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, and minimizing construction financing costs. The 3Party Covenant would reduce the cost of capital component of energy costs from new IGCC facilities by 34 percent and the overall cost of energy about 20 percent, making the technology cost competitive with pulverized coal (PC)[3] and natural gas combined cycle (NGCC) generation.

ES1. 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. 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. IGGC technology offers the potential to significantly improve generation efficiency and reduce air emissions from coal-fueled power plants, including sulfur dioxide (SO_2), oxides of nitrogen (NOx), particulates (PM), mercury (Hg) and carbon dioxide (CO_2).

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 and has been demonstrated at only a handful of facilities around the world. The overnight capital cost[4] of IGCC is currently 20 to 25 percent higher than PC systems and commercial reliability has not been proven. As a result, the $750 million investments required to build

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[1] The "equity investor" would be either an electric utility company, or independent power company with a purchase contract with a utility, 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" 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] 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.

IGCC facilities have not materialized despite significant public and private sector interest in the technology.

The objective of this report is to describe a program that could be used to support and stimulate commercial investment in an initial fleet of IGCC facilities by reducing investor risk and cost of capital. IGCC was selected as the focus of this paper because it represents an advanced technology for generating electricity with coal that is widely supported and could provide the basis for moving towards near zero-emissions coal generation.[5] The program will only be implemented if the federal government and participating states determine it is in the public interest to support commercial investments in IGCC power plants at this time.

ES2. Coal Electricity Generation in the U.S.

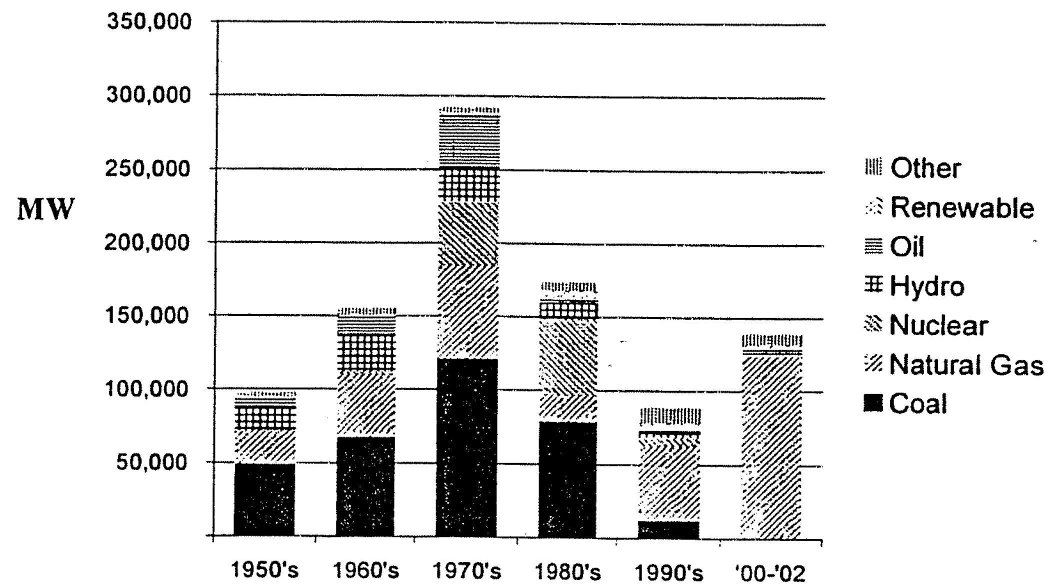
Coal is an abundant, relatively inexpensive, domestic resource with stable prices. Continued and expanded use of coal for electricity generation helps reduce U.S. dependence on imported fuels, relieve pressure on natural gas availability and prices that adversely affect other sectors of the economy, and support national energy and homeland security. However, continued or expanded use of coal electricity generation requires overcoming economic, financial, and environmental challenges that have virtually stopped construction of new coal generating capacity in recent years.

The U.S. has more coal reserves 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 reserves and more than a 250-year supply at current consumption.[6] 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 3 percent and 2 percent of world totals, respectively.[7]

Historically, the U.S. has relied on coal for the majority of its electricity production. In 2002, just over 50 percent of U.S. electricity was supplied by coal-fired power plants. However, the share of coal electricity generation is declining because, as illustrated in Figure ES-1, very few new coal power plants have been built in the U.S. in the last decade. Since 1990, less than 6 percent of new generating capacity is coal-fueled, while over 75 percent is natural gas-fired. In 2000-2002 alone, 140,000 MW of new capacity came on line—90 percent is natural gas fired and less than 1 percent uses coal.

[5] This type of financing program could be effective for other technologies that have similar characteristics.
[6] National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003.
[7] EIA, International Energy Annual 2001, Table 8.1.

Figure ES-0. U.S. Electric Generation Capacity Additions by On-line Date



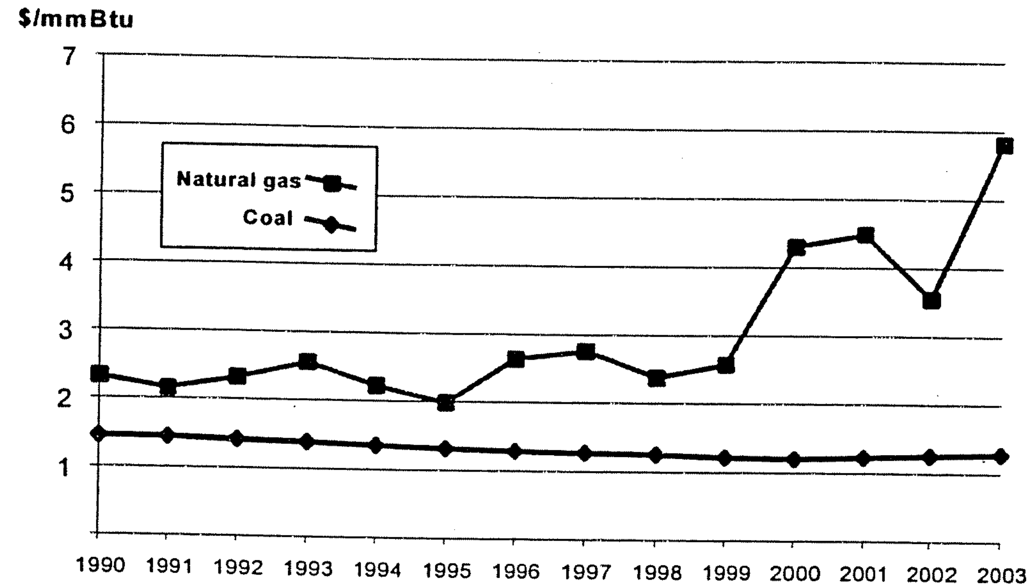
Source: Form EIA 860 "Annual Electric Generator Report," 2001.

Dependence on imported fuels is an important energy and national security concern. In 1972, just prior to the first Arab oil embargo, the U.S. imported 28 percent of its oil supply. In 2002, the U.S. imported 53 percent of its supply. In contrast, the U.S. is a net exporter of coal. Furthermore, up to a 90 day inventory of coal can be stockpiled at most generating plants. Coal generation supports U.S. energy independence and homeland security.

Coal use for electricity generation also helps 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. 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.[8] The high prices also lead major oil and gas companies to announce plans for multi-billion dollar investments in infrastructure to increase imports of liquefied natural gas (LNG) and

[8] 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).

Figure ES-2 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.

chemicals from mid-eastern countries, which is a trend that will only exacerbate energy dependence and security concerns.[9]

As illustrated in Figure ES-2, another important characteristic of coal is price stability, which is in sharp contrast to the price volatility of natural gas. Since the mid-1990's, 175,000 MW of new natural gas generating capacity has been added at a cost of over $100 billion. In 2003, high natural gas prices and soft electricity markets rendered most of this new capacity uneconomic. Duke Energy announced in January, 2004 that it is taking a $3 billion write off from 2003 earnings, in large part because of the decline in value of its recent investments in natural gas generation.[10] In addition, many natural gas-fired power plants are being returned to lending institutions, making several money center banks significant owners of electric power generation in the U.S. Natural gas price volatility can significantly and unexpectedly alter the economics of natural gas electricity supply, whereas the stability of coal prices helps maintain electricity price stability.

Despite the many advantages of coal generation, adding new coal capacity requires overcoming significant challenges. Coal power plants require twice as much capital and take several years longer to construct than NGCC plants. These factors make coal plants more difficult to finance, subject to more regulatory uncertainty, and generally less economically attractive than natural gas plants. The financial challenges are particularly

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[9] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.
[10] See http://www.dukeenergy.com/news/releases/2004/jan/2004010701.asp

important today because the credit ratings of many electric power companies have declined in recent years. A November 2003 analyst report by Standards & Poors indicates 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."[11] Capital formation to build coal generation is a significant challenge for new capacity development.

The financial challenges facing coal generation are compounded by environmental concerns associated with its use. Coal combustion in traditional PC boilers produces harmful by-product emissions that raise local, regional, and global environmental concerns. In addition to SO_2, NOx, and mercury emissions that have local and regional impacts, CO_2 emissions from coal combustion are a concern because CO_2 is a greenhouse gas that has been linked to global climate change.[12] Continued and expanded coal use for electricity generation around the world is projected by the Energy Information Administration (EIA) to increase CO_2 emissions from coal combustion 45 percent by 2025.[13] Concern about this trend has helped energize opposition to new PC plant construction in the U.S. and is an important factor that has made it increasingly difficult to finance new coal power plant projects.

Addressing these environmental concerns requires deploying new technologies like IGCC that can produce electricity from coal with substantially lower air pollutant emissions, including the potential for carbon capture and sequestration. However, deploying IGCC requires a large capital investment in a technology that is currently more expensive and poses more risks than PC or natural gas technologies.

For IGCC to be perceived as mature, reliable, and economic, 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 program.

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

[12] In its Third Assessment Report, the Intergovernmental Panel on Climate Change (IPCC) indicated: "Emissions of greenhouse gases and aerosols due to human activities continue to alter the atmosphere in ways that are expected to affect the climate;" IPCC, Third Assessment Report of Working Group I, Summary for Policymakers, p. 5.

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

ES3. 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:

1. *Federal Loan Guarantee:* The program for implementing the 3Party Covenant would be established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee would include allowing for an 80/20 debt to equity financing structure and would require that a proposed project obtain from a state PUC an assured revenue stream to cover return of capital, [14] cost of capital and operating costs.
2. *State PUC Approval Process:* States interested in participating in the program would voluntarily opt-in by adopting utility regulatory provisions for implementation by the state PUC concerning review, approval, and recovery of IGCC project costs,[15] which in some states would require legislative action to create appropriate enabling authority. Specifically, a state PUC (or other utility rate making authority in the case of public power), acting under state enabling authority, would agree to assure dedicated revenues to IGCC projects sufficient to cover return of capital, cost of capital, and operating costs (e.g., operation, maintenance, fuel costs and taxes).[16] The state PUC would provide 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 that the plant qualifies for cost recovery and establishing rate mechanisms to provide cost recovery, including cost of capital. The certification by the state PUC would occur up-front when the decision to proceed with the project was being made and state PUC prudence reviews would occur as construction was ongoing, which would reduce the construction risks borne by the developer, avoid accrual of construction financing expenses, and protect ratepayers.
3. *Equity Investor*: The equity investor under the 3Party Covenant would be either an electric utility or an independent power producer that secures a long-term power contract with a utility. The investor would contribute equity for 20 percent of project costs and negotiate performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return would be determined and approved by the state PUC before construction begins.

[14] As used in this paper, the term "return of capital" means depreciation and amortization.
[15] As used in this paper, the term "project costs" means the cost of capital, return of capital, and operating costs.
[16] Depending on the ownership structure of the IGCC project, the Federal Energy Regulatory Commission (FERC) may also have a role.

State PUC certification and approval would create an assured, dedicated revenue stream to cover the construction, operating, and market risks of the IGCC plant. From the standpoint of the federal government, this assurance provides enhanced credit worthiness, strong protection against loan default, and a lower scoring requirement in the federal budget (see discussion below). From the standpoint of the equity investor, this assurance enables underwriting of the federally guaranteed loan in the context of a higher debt-equity ratio (80/20) than available under traditional utility financing terms (55/45). From the standpoint of purchaser of the long-term debt, the federal guarantee provides a "AAA" credit rating backed by the full faith and credit of the Unites States government.

It would be the responsibility of the state PUC, through a highly transparent and public process, to evaluate the IGCC investment decisions, including the feasibility of technology application, before costs could be passed along to ratepayers. The state PUC would first conduct a due-diligence certification process, through which it would publicly examine 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 issue. After commencement of plant construction and thereafter, the state PUC would conduct ongoing prudence reviews of construction and operating costs. State PUC certification and prudence reviews would protect ratepayers and would be the basis for the state PUC determining whether to approve recovery of project costs.

Fundamental challenges addressed by the 3Party Covenant include:

1. *Challenge:* Equity investors are unwilling to invest $750 million to build IGCC power plants.

   3Party Covenant: Equity investment is reduced to 20 percent (from around 45 percent under traditional utility financing) through the terms of a non-recourse loan backed by a federal loan guarantee and an assured revenue stream approved by the state PUC that provides for a fixed equity return and repayment of debt.

2. *Challenge:* Equity investors are unable to raise attractive debt to finance IGCC.

   3Party Covenant: Provides federal loan guarantee with "AAA" credit rating backed by the full faith and credit of the United State government rather than relying on project risks or corporate credit.

3. *Challenge:* Significant construction and operating risk are associated with deploying new generation technology, particularly at the investment scale of IGCC.

   3Party Covenant: Requires up-front state PUC process to approve a stream of revenues to cover return of capital, cost of capital, and operating costs through rate adjustment clauses—the construction and operating risks are thereby shifted to and spread across ratepayers based on state PUC finding that doing so is in the public interest.

4. *Challenge:* Market risks in deregulated wholesale electricity markets make large capital investments in deploying IGCC unattractive.

   3Party Covenant: Removes market risks, after state PUC review and approval, through state PUC assured revenue stream.

5. *Challenge:* Overnight capital cost and resulting cost of energy are higher for IGCC versus PC for coal generation.

   3Party Covenant: Reduces IGCC energy costs to levels below new PC energy costs through financing savings from higher debt/equity ratio, lower cost of long-term debt, and minimizing of construction financing costs.

ES4. Cost of Energy Impact of 3Party Covenant

The 3Party Covenant program would reduce the cost of energy from an IGCC power plant 19 to 22 percent. The cost of energy reductions would result from:

1. 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 total plant investment).
2. Lowering the cost of debt through the federal loan guarantee, which would reduce the interest charge from a typical 6.5 percent for a mid-grade utility bond in January 2003 to the 5.5 percent rate associated with a federal agency bond (essentially a 75 to 100 basis point reduction in the cost of long-term debt).
3. Providing for a significantly higher ratio of debt to equity, which would move from a traditional utility 55/45 ratio to 80/20 under the 3Party Covenant. The higher ratio would result in the replacement of 19 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 about 25 percent of project costs.[17]

These changes would reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant from about 12 percent (traditional utility financing) to 8 percent (3Party Covenant), reduce the cost of capital component of energy costs by 34 percent, and reduce the total energy cost 19 to 22 percent. As a result, financing savings under the 3Party Covenant can offset up to $600/kW of overnight capital cost differential between an IGCC and PC power plant, or alternatively, these savings could offset almost a 20 percent decline in capacity factor.

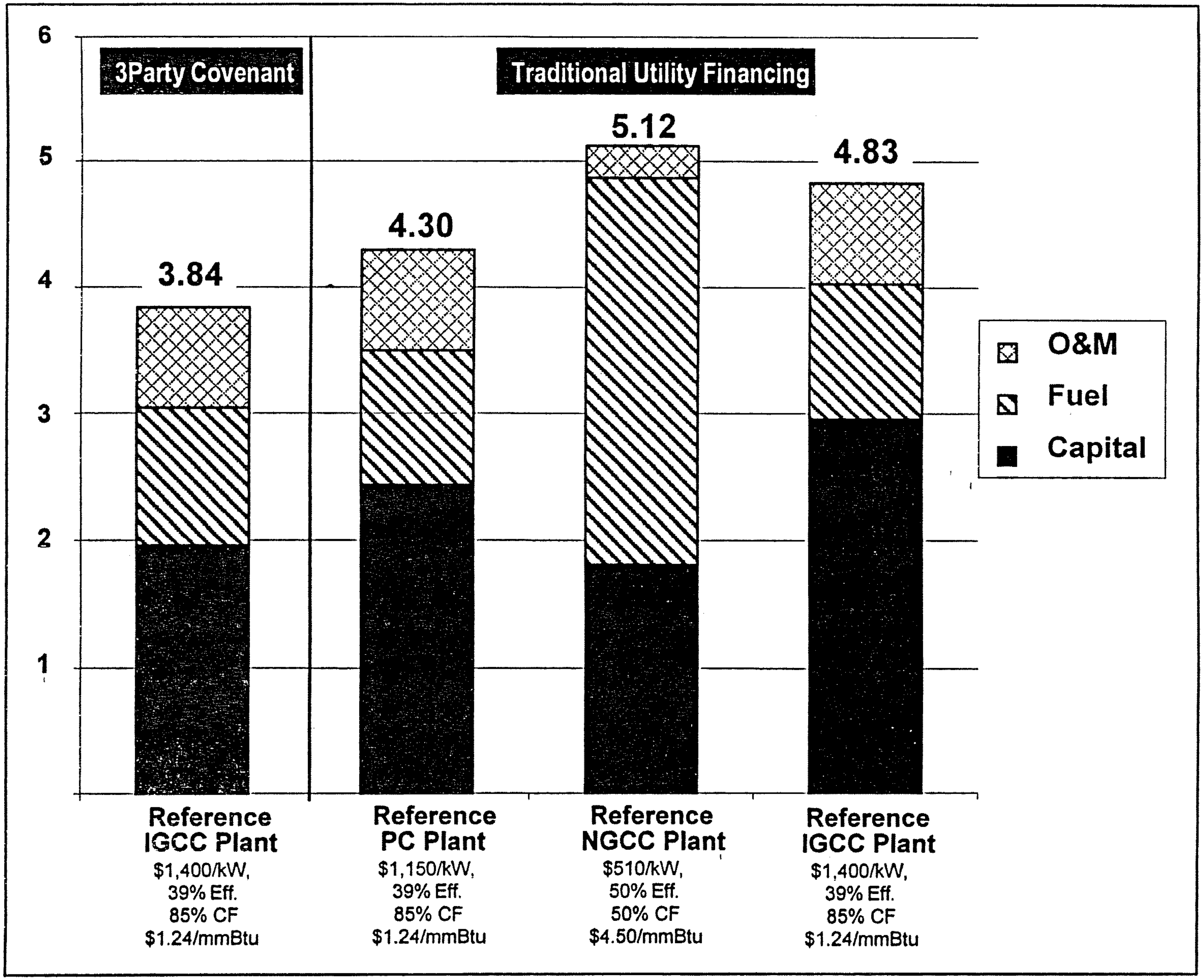
[17] The base case assumption of a 55 percent debt and 11.5 percent equity return under traditional utility financing is somewhat more conservative than the November 2003 Public Service Commission of Wisconsin order that approved construction of two PC plants with only 45 percent debt and a 12.7 percent after-tax equity return. See Wisconsin Electric Power Co., 228PUR4th 444, 2003 WL 22663829 (WISC. PSC Nov. 10, 2003).

Table ES-1 compares the cost of energy estimates for a Reference IGCC plant under the 3Party Covenant to the cost of energy estimates for Reference PC, NGCC and IGCC plants under traditional utility financing scenarios. **Table ES-1 and Figure ES-3 illustrate that the overnight capital cost of the IGCC plant is 22 percent higher than the overnight capital cost of the PC plant, but when the IGCC plant is financed under the 3Party Covenant, its energy cost is reduced 20 percent, resulting in an energy cost that is 11 percent less than the PC plant.**

Table ES-1. Cost of Energy Comparison of Reference PC and NGCC Plants Financed Traditionally to Reference IGCC Plant Financed with 3Party Covenant

	Traditional Utility Financing			3Party Covenant
	IGCC (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)	NGCC ($4.50 gas; 50% CF; 60% Eff.)	PC ($1,150/kW; 85% CF; 39% Eff.)	IGCC (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)
Design and Construction				
Plant Size (MW)	550	500	550	550
Total Plant Cost ($/kW)	$1,400	$510	$1,150	$1,400
Interest During Construction (CWIP*) ($/Kw)	$168	$19	$138	0*
Total Plant Investment ($/kW)	$1,568	$529	$1,288	$1,400
Operation				
Fuel cost ($/mmBtu)	$1.24	$4.50	$1.24	$1.24
Plant Efficiency (%)	39%	50%	39%	39%
Heat Rate (Btu/kWh HHV)	8,700.00	6,800.00	8,700.00	8,700.00
Plant Capacity Factor (%)	85%	50%	85%	85%
Annual Generation (MWh)	4,095,300	2,190,000	4,095,300	4,095,300
Financing				
Percentage Debt	55%	55%	55%	80%
Debt Interest Rate	6.5%	6.5%	6.5%	5.5%
Percent Equity	45.0%	45.0%	45.0%	20.0%
After tax Equity Return	11.5%	11.5%	11.5%	11.5%
Tax rate (Federal & State)	38.2%	38.2%	38.2%	38.2%
Pre-tax Equity Return	18.6%	18.6%	18.6%	18.6%
Pre-tax WACC	11.9%	11.9%	11.9%	8.1%
Levelized Carrying Charge	15.7%	15.5%	15.7%	10.4%
Estimated Cost of Energy				
O&M (cent/kWh)	0.80	0.25	0.80	0.80
Fuel (cent/kWh)	1.08	3.06	1.08	1.08
Capital (cent/kWh)	2.95	1.81	2.42	1.96
Cost of Energy (cent/kWh)	**4.83**	**5.12**	**4.30**	**3.84**

Figure ES-3. Cost of Energy Comparison between Reference IGCC, PC and NGCC plants



Important to the cost of developing a power plant is whether a project is being developed on a greenfield site, or is repowering an existing facility. Virtually all cost estimates for IGCC, including those presented here, assume a greenfield plant, but cost savings may be possible in repowering scenarios. Repowering of existing coal facilitates may allow developers to take advantage of existing coal handling, electricity interconnect, and steam turbine facilities that would reduce the cost of the project. Likewise, repowering of an existing natural gas combined cycle facility, assuming there was ample space and coal delivery capability at the site, could enable a developer to utilize the existing combined cycle power block, which accounts for roughly 30 to 35 percent of IGCC capital costs.

The financial savings under the 3Party Covenant could be used, in whole or in part, for establishment of reserve funds approved by the state PUC. The reserves could be used for several important purposes, including:

- Construction cost overruns;
- Early reliability or operating difficulties;
- Bond redemption to reduce ongoing costs to ratepayers; and/or
- Deployment of advanced technologies to mitigate CO_2 emissions (see discussion in Section 2.41 below).

Establishment of reserves would give additional comfort to investors and the federal government by adding another layer of protection onto the already solid foundation provided by the state PUC review, approval, and cost recovery procedures required under the 3Party Covenant, which are described below.

ES5. Requirements for State Participation

Participation in the 3Party Covenant would require a state PUC to establish procedures for review, approval, and cost recovery for qualifying IGCC facilities. These procedures would include the following elements:

1. Before any construction began, the state PUC would review 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 would include consideration of several factors concerning the likely benefits and costs of the proposed IGCC plant and the need for base load power. Based on satisfactory determination, the state PUC would issue a certificate of public convenience and necessity for the new plant. In the certificate, the state PUC would permanently establish the return on equity for the project and approve the use of an adjustment clause for future recovery of incurred costs (including recovery, during construction, of costs of capital on construction work in progress (CWIP)).

2. After issuance of a certificate and as construction progresses, the state PUC would periodically conduct a prudence review on an expedited basis and approve the portion of the IGCC plant constructed during the preceding period. As each portion of construction expenditures (CWIP) was approved in the ongoing review, the cost of capital for the approved expenditures would become recoverable on an ongoing basis through, and would be reflected in, the approved adjustment clause.

   The duration of each periodic (e.g., six-month) review proceeding would be limited (e.g., to three months). As a result, cost of capital during construction would be 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 would be recovered on an ongoing basis during construction, a much smaller amount would be 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 cost of capital) could not thereafter be challenged, in the absence of fraud or concealment. For example, issues concerning excessive cost, inadequate quality control, failure to complete, or inability to operate properly could not raised. In this way, the state PUC's review and protective approval would be updated during and after plant construction.

   Disbursement of the federally guaranteed loan would be coordinated with the ongoing review process. As each portion of construction expenditures was reviewed and approved for recovery through the adjustment clause, the federally guaranteed loan would be 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 would conduct on an expedited basis a prudence review of the plant's operating costs during the preceding period. As the operating costs were approved in the ongoing review, the approved operating costs become recoverable on an ongoing basis through, and would be 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 related cost of capital also become recoverable through, and would be reflected in, the approved adjustment clause. The state PUC would require the ICGG plant owner to handle separately the revenue stream from the approved adjustment clause and place the revenues in a segregated account that could only be used to pay project costs, including cost of capital.

Under these procedures, state PUC certification and approval would create an assured, dedicated revenue stream to cover the construction, operating, and market risks of the IGCC plant.

ES6. 3Party Covenant Implementation

Implementation of the 3Party Covenant would require federal legislation authorizing loan guarantees for qualifying IGCC projects. As discussed above, the 3Party Covenant would reduce the risk of a federal loan guarantee program. The primary risk to the federal loan guarantee under the 3Party Covenant is the regulatory risk that state PUC determinations regarding cost recovery would be modified or overturned at a future date. This regulatory risk, which could be reduced or removed through state legislation or other state action, is much lower than the risk associated with merchant financing of a new, capital intensive technology.

Proposed energy legislation debated by Congress in 2003 provides a structure that could accommodate the 3Party Covenant by authorizing federal loan guarantees and tax incentives for IGCC plants and appropriations reflecting the federal budget scoring of the federal loan guarantees. The 3Party Covenant could be used to implement these authorizations and appropriations, if they were passed by Congress and if the Department of Energy or other implementing agency decided to use this approach.

Using the 3Party Covenant to implement federal loan guarantees for IGCC plants would reduce the risk, and therefore the budgetary impact, of such loan guarantees and, for a given amount of appropriations, would allow a larger number of IGCC plants to be covered. 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 appropriations in the year the program is established of enough funds to cover the estimated present value cost associated with the guarantees, which is determined by the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors to make this determination. To the extent these 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 would be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, for example, then $5 billion worth of loan guarantees could be provided (enough for about 6 projects) with a federal budget impact of $500 million.

1.0 INTRODUCTION

The U.S. electric power industry operates about 900 giga-watts[18] of power plant capacity, over 160,000 miles[19] of high voltage transmission, and a distribution system that connects electricity service to virtually every residence and business in the country. This infrastructure required hundreds of billions of public and private investment, which was supported by rate-of-return regulation and other regulatory structures that served to reduce investor risks and assure fair returns.

These investments have, on the whole, served the country well, providing the U.S. with relatively low electricity prices and one of the most reliable electricity systems in the world. Nonetheless, the summer 2003 blackout across the eastern U.S. and the 2000-2001 California energy crisis have focused attention on the future adequacy of the existing infrastructure and on developing policy and regulatory approaches to support the investments needed to ensure the continuation of ample, reliable, and affordable electricity.

The first requirement for a secure electricity supply is ensuring adequate generating capacity is available to meet growing demand. Historically, the U.S. has relied on its domestic coal resource to generate the majority of its electricity. However, increasing environmental scrutiny, costly and timely permitting processes, and limited access to attractive capital in the face of uncertain and changing electricity markets has made it increasingly difficult and unattractive for developers to build new, capital intensive and environmentally disfavored coal power plants.

Nonetheless, there are powerful economic and energy security reasons for continued U.S. reliance on coal as a primary generation fuel. Coal is an abundant, relatively inexpensive domestic resource with stable prices. Continued and expanded use of coal for electricity generation would help reduce U.S. dependence on imported fuels to promote energy security, relieve pressure on natural gas availability and prices that adversely affect other sectors of the economy, and promote U.S. leadership and export of advanced coal technologies.

If coal is going to continue to play a significant role in the future U.S. electricity supply equation, advanced technologies need to be deployed that can meet environmental challenges, including progress towards addressing climate change concerns, while, at the same time, providing investors reasonable risk/return tradeoffs and producing competitively priced electricity. As discussed below, this is the fundamental challenge facing IGCC that must be addressed for it to become a viable commercial generation alternative.

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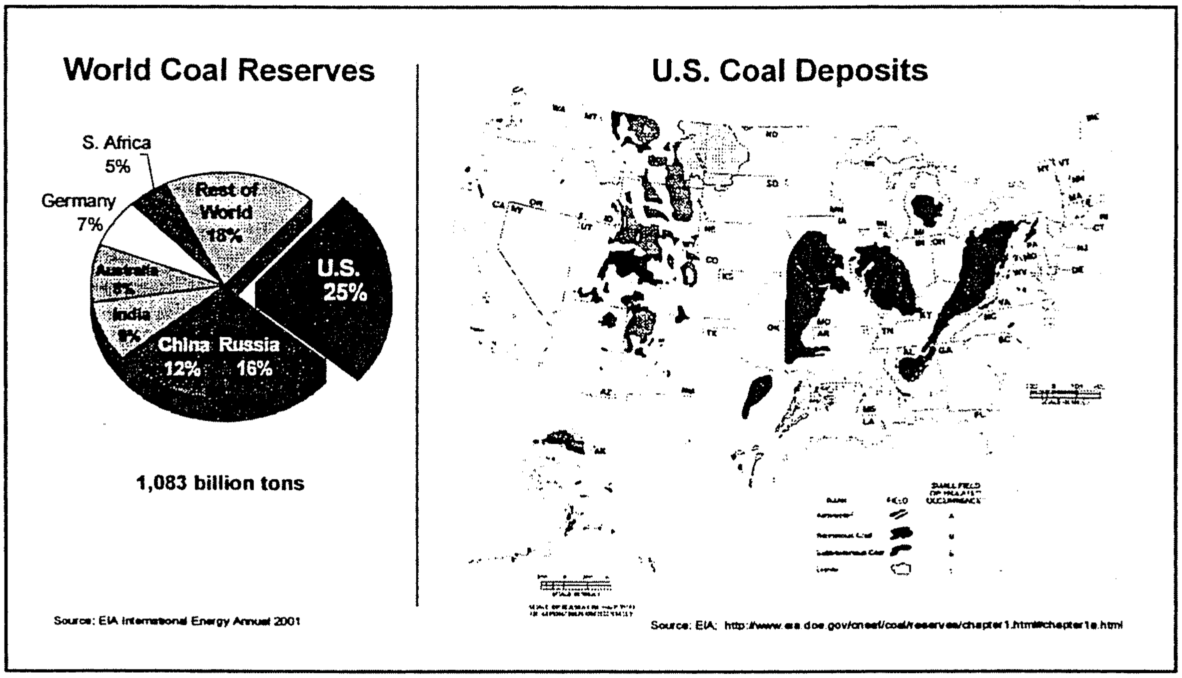
[18] Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report," 2001.
[19] Edison Electric Institute (EEI), "Energy Infrastructure, Electricity Transmission Lines," Feb. 2002.

1.1 Coal and Electricity Generation in the U.S.

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 reserves and more than a 250-year supply at current consumption.[20] 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 3 percent and 2 percent of world totals, respectively.[21] As illustrated in Figure 1-1, U.S. coal reserves are dispersed across several regions, including states in the Appalachian, Midwest, Rocky Mountain, Southern regions and in Alaska.

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



In 2002, coal-fired power plants accounted for just over 50 percent of U.S. electricity generation. The U.S. began building coal-fired power plants in the early 1900's, and coal generating capacity increased steadily through the 1980s.[22] Figure 1-2 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 1-2 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

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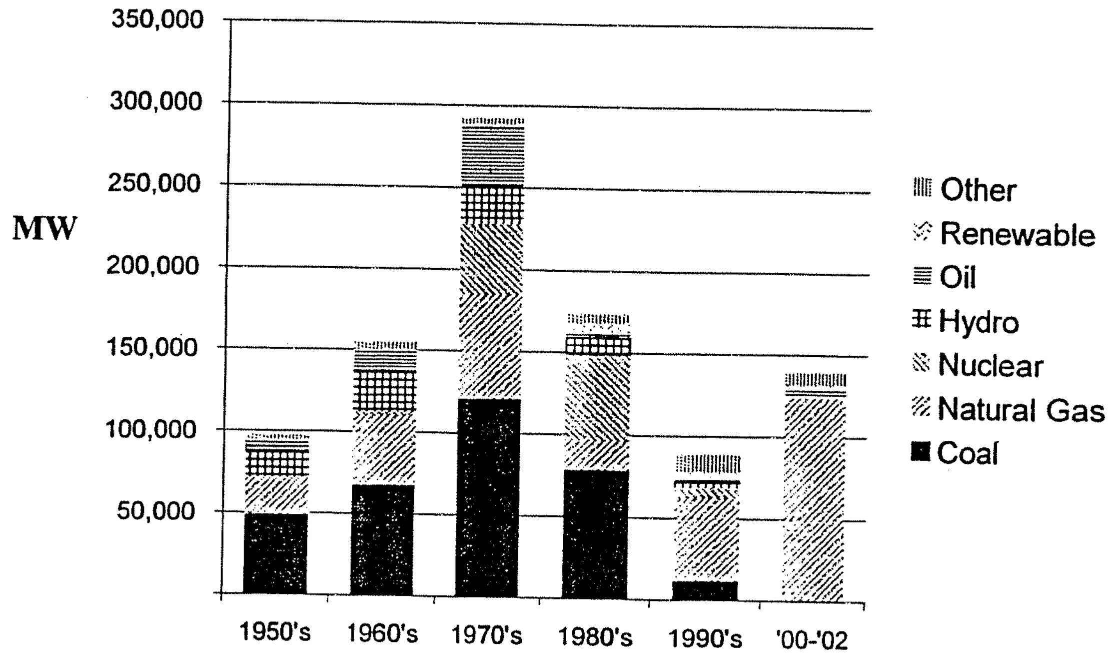
[20] National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003.
[21] EIA, International Energy Annual 2001, Table 8.1.
[22] See EIA, The Changing Structure of the Electric Power Industry 2000, An Update, Oct. 2000 (Appendix A, History of the U.S. Electric Power Industry, 1882-1991).

Figure 0-2. U.S. Electric Generation Capacity Additions by On-line Date



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

capacity each decade. About 320,000 MW of coal capacity came on-line during this 40-year period. However, since 1990, less than 6 percent of new capacity has been coal-fueled, while over 75 percent of the new capacity uses natural gas. In the last three years, a total of 140,000 MW of new generating capacity was added—over 90 percent of it is natural gas-fired, and less than 1 percent of it is coal-fired.[23]

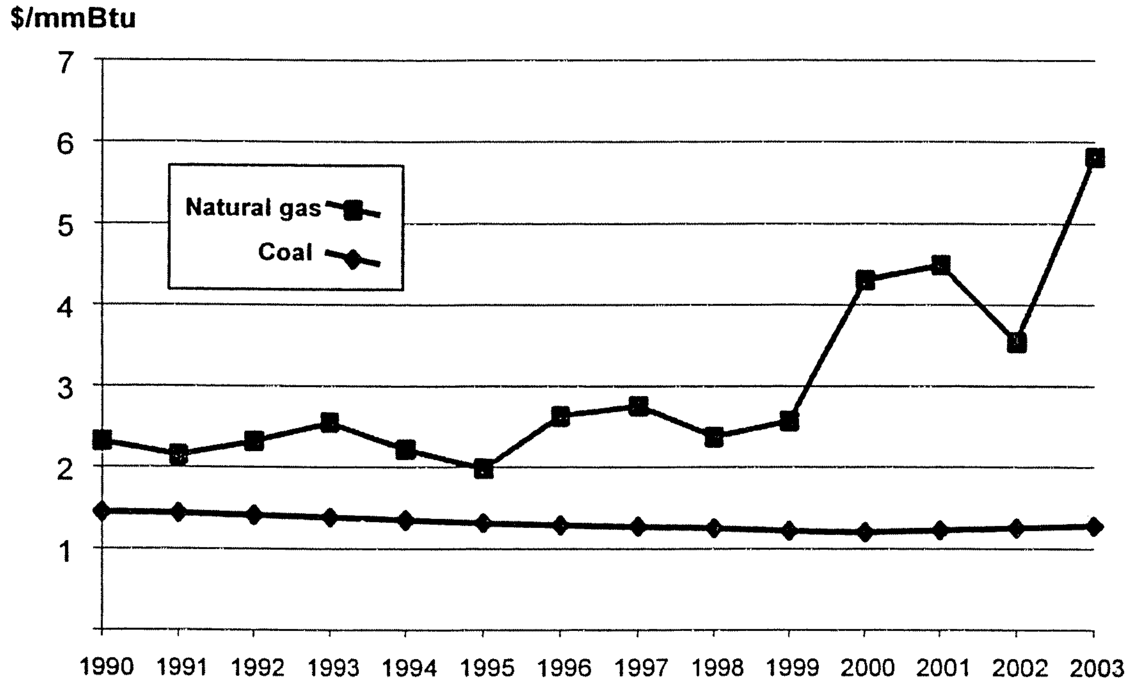
1.2 Coal and Natural Gas Prices in the U.S.

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 coal prices have remained stable and slowly declined.

One result of the high natural gas prices in 2003, combined with a softening of wholesale electricity markets, is that many of the natural gas power plants built in recent years have become uneconomic and decreased in value to a fraction of their original cost.[24] The result has been that a number of natural gas power plants financed with non-recourse debt

[23] See Form EIA 860 "Annual Electric Generator Report."
[24] An article in The Street.Com recently indicated that Duke Energy "had been offered just '20 cents on the dollar for state-of-the-art facilities.' So for now, at least, the company appears to be stuck with a huge fleet of power plants -- running at just 25% of capacity -- that it spent $8 billion to build." See Melissa Davis, "Duke CEO Getting Ready to Roar," The Street.Com, Oct. 27, 2003.

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.

are now being turned over to lending institutions, making these lenders significant owners of electric generating capacity in the U.S.

The impact of high natural gas prices has not been isolated to the electric industry, but has also 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.[25]

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[25] 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

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. Coal price stability, on the other hand, translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel. 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.[26] In contrast, increased use of natural gas for electricity generation can lead to concurrent increases in heating, process and electricity costs that adversely affect commercial, industrial and residential consumers.

1.3 Commercial Interest in Coal Power

A renewed appreciation for the volatility and unpredictability of natural gas prices helped rejuvenate interest in the development of new coal-fired generating capacity in 2003. According to the Department of Energy, as of November 2003, 93 new coal plants had been proposed in the U.S., representing 61,000 MW of new coal capacity and $63 billion of potential investment. While it is unclear how much of this proposed new capacity will actually be developed, the data indicate a strong resurgence of interest in coal power plants and suggest that if the economics and risks of new coal technologies were acceptable, and attractive financing was available to build them, there would be commercial interest in deployment.

1.4 World Coal Use

The U.S. is not the only country that relies on coal as a vital energy resource. In 2001, worldwide coal consumption was 5.26 billion short tons. It is projected to grow by 1.5 percent per year and reach 7.48 billion tons by 2025. By 2025, China is projected to account for almost 39 percent of world coal consumption (2.917 billion tons), while the U.S. and India are projected to account for 19 and 8 percent, respectively.[27]

Today, about 55 percent of coal use around the world is for electricity generation[28] and essentially all of the growth in world coal demand over the next several decades is projected to come from growth in coal-powered electricity generation. The International Energy Agency (IEA) projects that an additional 1,400 giga-watts of coal-fired electric generating capacity will be built by 2030,[29] which is about 4 times the coal-fired capacity

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).

[26] EIA, "Annual Energy Outlook 2003 (AEO 2003)," Jan. 2003 (Table A16).

[27] EIA, "International Energy Outlook 2003 (IEO 2003)," p. 77-78, May 2003.

[28] IEO 2003, p. 78.

[29] 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.

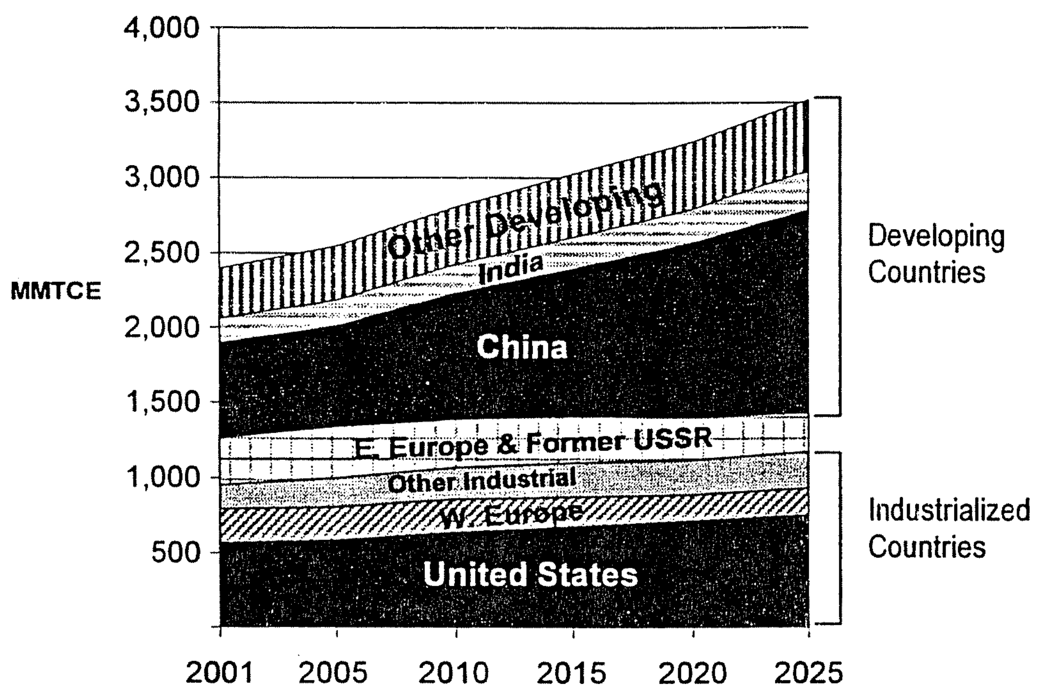
in the U.S. today. EIA forecasts that increased use of coal for electricity generation in China and India alone will account for 75 percent of the growth in coal consumption worldwide by 2025.[30]

1.5 World Coal Use and Climate Change

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 increasing electricity demand. This expanded coal use will help developing countries provide electricity where today there is none and help industrialized countries maintain stable, low-cost electricity supplies. However, because coal has the highest carbon content of any fossil fuel, its continued and expanded use threatens to substantially increase worldwide CO_2 emissions and exacerbate global climate change concerns.

Currently, about 37 percent of anthropogenic CO_2 emissions worldwide are attributed to coal combustion (2.427 billion metric tons carbon equivalent).[31] Coal-fired power plants account for 55 percent of world coal consumption and are responsible for about 20

Figure 1-4. Projected World CO_2 Emissions from Coal Consumption



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

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[30] EIA, IEO 2003, p. 77.

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

percent of world CO_2 emissions.[32] As illustrated in Figure 1-4, world CO_2 emissions from coal use are projected to increase 45 percent by 2025.[33] Essentially all the increase is attributed to electricity generation, which means mass CO_2 emissions from coal-fired power plants are projected to approximately double in the next 25 years.

CO_2 emissions increases in developing countries are far outpacing increases in industrialized countries as more energy is demanded in their expanding and modernizing economies. The increase in greenhouse gas emissions in China alone is projected to nearly equal the increase from the entire industrialized world by 2030.[34] A significant percentage of this increase is attributed to increased coal use for electricity generation.

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. Moreover, how the U.S. electric power sector utilizes coal and deploys advanced coal power systems in the next decade will have significant implications for domestic and international energy markets, as well as regional, national and global environmental progress. Advanced coal technologies (such as IGCC) that offer the potential to address environmental concerns at reduced cost provide a potential path forward for removing the stigma attached to coal, reducing opposition to coal power system development, and enabling coal to become part of the solution for reducing greenhouse gas emissions.

1.6 Challenges for IGCC Market Penetration

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 cost and risk concerns. The capital costs associated with a new IGCC power plant are currently about 20 to 25 percent higher than the cost of a new coal boiler, and these costs are less certain than the costs of boiler technologies. Furthermore, unlike pulverized coal boilers, IGCC technology is not perceived to be mature, so its risks and costs 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 commercial base load coal generation.[35] To address the higher initial costs and higher risks associated with building the first commercial IGCC facilities, and to stimulate commercial deployment that will bring costs down and prove reliability, programs are needed to help reduce capital costs and investor risks.

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[32] Estimated based on coal combustion accounting for 37% of world CO_2 emissions and electricity production accounting for 55% of world coal use (0.37*0.55=0.2).
[33] EIA, International Energy Outlook 2003, Table A-13, p.194.
[34] "China's Boom Adds to Global Warming Problems," New York Times, October 22, 2003 (citing data from the International Energy Agency).
[35] As discussed in Section 2.4 below, the incorporation of redundant gasification capacity should enable IGCC facilities to readily achieve this level of availability.

Furthermore, the electric utility industry today is weaker financially than it has been in the past. A November 2003 analyst report by Standards and Poors indicted 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."[36]

Lower credit ratings make if more difficult and costly for power companies to raise money for large, capital-intensive coal projects 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. 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.

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 IGGC 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."[37] 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.

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

[37] Wisconsin Electric Power Co., 228 PUR4th 444, 2003 WL 22663829 at 26 (Wisc. P.S.C. Nov. 10, 2003).

2.0 IGCC TECHNOLOGY DESCRIPTION

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 made 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.

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.[38]

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 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,[39] 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.[40]

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.[41] 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.[42] Of these projects, 128 were identified as active-real projects (operating or under construction) that included 366 gasifiers.[43] There are at least fifteen suppliers of commercial gasification technology.[44] Table 2.1 lists the

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[38] 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.

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

[40] 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.

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

[42] Id.

[43] Id.

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

largest commercial gasification projects operating or under development around the world as of January 2000.

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. Specifically, there are twelve major IGCC plants operating internationally.[45] Five of these plants were designed specifically for commercial-scale electricity production; the remainder are used for refining and petrochemical applications with electricity production as a secondary process.[46] Each of these five facilities is discussed in detail in Section 2.2 below.

[45] Id. NETL indicates there were eleven IGCC facilities operating as of December 2002 and at least one more IGCC facility came on-line in 2003.
[46] Id., 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	ChevronTexaco	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	ChevronTexaco	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	ChevronTexaco	982	1999[b]	asphalt	Electricity & H_2
Sasol-I	South Africa	Lurgi Dry Ash	911	1955	Subbit Coal	FT liquids
Total France/ edf /ChevronTexaco	France	ChevronTexaco	895	2003[a]	Fuel oil	Electricity & 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	CheveronTexaco	621	1984	Bitumen	H_2 & CO
Hydro Agri Brunsbuttel	Germany	Shell	615	1978	Hvy Vac res	Ammonia
Global Energy Inc	U.S.	ConocoPhillips	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.	ChevronTexaco	558	1999[b]	Fluid petcoke	Electricity
API Raffineria	Italy	ChevronTexaco	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.	ChevronTexaco	455	1996	Coal	Electricity
Ultrafertil	Brazil	Shell	451	1979	Asphalt res	Ammonia
Shanghai Pacific Chemical Corp	China	ChevronTexaco	439	1995	Anthracite coal	Methanol & Town gas
Exxon USA	U.S.	ChevronTexaco	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	ChevronTexaco	405	1982	Ref residue	Ammonia & methanol
Esso Singapore	Singapore	ChevronTexaco	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.

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 components 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 it 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.[47] Coal handling equipment accounts for about 12 percent of the capital cost of an IGCC.[48]

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.[49] 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.[50]

IGCC systems can incorporate any one of a number of gasifier designs, but all are based on one of three generic configurations:[51]

> *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

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

[48] 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).

[49] 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..

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

[51] 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.[52]

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.[53]

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 ChevronTexaco, ConocoPhillips,[54] Shell, Prenflo, and Noell.[55]

The commercial gasification processes believed most suited for near-term IGCC applications using coal or petroleum coke feedstocks are the ChevronTexaco, ConocoPhillips, and Shell entrained-flow gasifiers.[56] Each of these technologies is currently used at a 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.[57] 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.[58]

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

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[52] Id., p. 1-8.
[53] Id., p. 1-10.
[54] 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).
[55] NETL, Major Environmental Aspects, p. 1-10–1-11.
[56] SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 8.
[57] Id., p. 7.
[58] Id.

largest parasitic load on an IGCC facility utilizing an oxygen-blown gasifier.[59] 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.[60]

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.[61] 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. For this reason, the next generation of IGCC facilities are expected to be based on entrained-flow, oxygen-blown (rather than air-blown) gasification technologies.[62]

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.[63]

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 (ChevronTexaco technology uses the quench method). 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.[64]

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.[65] 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.[66] The particulate material, including char and fly ash, is then typically recycled

[59] Id., p. 14.
[60] Id.
[61] Id., p. 9.
[62] Id.
[63] EPRI/NETL, Appendix A, p. A-30.
[64] Id., p. 7-15.
[65] 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.
[66] NETL, Major Environmental Aspects, p. 1-12.

back to the gasifier. When filters are used, they are cleaned by periodically back pulsing them with fuel gas to remove trapped material.[67]

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.[68] 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).[69] 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.[70]

The cost of these gas clean-up systems and associated piping accounts for about 7 percent of total plant costs.[71]

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. 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 HRSG to generate steam for a steam turbine to complete the combined power cycle.[72]

Syngas fuel is essentially interchangeable with natural gas as fuel for combustion turbines (the Wabash 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.[73] This large volume requires different piping and control valves 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.[74]

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[67] Id.
[68] SFA Pacific, Inc., p. 10.
[69] Id.
[70] NETL, Major Environmental Aspects, p. 1-12.
[71] EPRI/NETL, Appendix A, p. A-30.
[72] NETL, Major Environmental Aspects, p. 1-13.
[73] SFA Pacific, Inc., p. 12.
[74] Id.

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.[75] 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.[76]

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 IGGC facilities are operating today that were designed for commercial electricity production. Four use either coal or petroleum coke feedstocks and one uses asphalt feedstock. These facilities, including two in the U.S., two in Europe, and one in Japan are described below and summarized in Table 2.3.

[75] EPRI/NETL, Updated Cost and Performance Estimates, p. 4-72.

[76] 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.

2.21 Wabash Power Station, Terre Haute, Indian

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.[77]

The project was undertaken as a joint venture between Destec Energy Inc. of Houston and PSI Energy, an investor owned utility in Indiana. The plant is a 262 MW (net) facility utilizing the ConocoPhillips gasification process based on an enrained-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 project cost was $438 million ($1,680/kW in mid-2000 dollars), half of which was paid for by DOE.[78]

The plant operating performance has generally improved over time as systems have been modified and optimized. From 1998-1999 plant availability (including both the gasification island and the power train) averaged 70 percent, which improved to about 74 percent in 2000-2001 and reached 84 percent in 2002.

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 ChevronTexaco 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 a repowering of an existing coal plant. Construction on the facility began in October 1994 and operation began in September1996.[79]

Polk Power Station is a 250 MW (net) facility that has successfully 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).[80]

Like Wabash, the Polk Stations operating performance has been relatively good. The availability of the gasification island steadily improved from just over 60 percent in 1998

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[77] NETL, Major Environmental Aspects, Appendix 1B-9.
[78] DOE. Clean Coal Technology Topical Report Number 20, p. 12.
[79] NETL, "Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report," Aug. 2002, p. I-1.
[80] Id., p. 4-1—4-2.

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.[81]

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 successful 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 gasifier. The plant, which was built to utilize a number of different imported coals, differs significantly from its counterparts 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), but makes it more complex and difficult to start, which has affected its availability. After encountering operating problems in its initial years, design changes were made in 1997 that significantly improved plant performance. The plant operated at 84 percent availability in 2002.

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.[82]

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 would be required of a commercial coal generating facility in the U.S.[83]

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[81] Id., p. ES-5.
[82] NETL, Major Environmental Aspects, p. 1B-12.
[83] Id.

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 ChevronTexaco 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 96.1 percent gasification syngas availability. The facility employs an advanced sulfur recovery system that removes 99.8 percent of sulfur from the syngas.[84]

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	ChevronTexaco	Shell	Prenflo	ChevronTexaco
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.

2.3 Environmental Performance of IGCC Power Plants

Environmental performance is a critical consideration in the development of new power generation facilities. Public acceptance, permitting success and timing, and compliance costs are all directly affected by environmental performance and significantly impact the economics and site selection for power plant projects in the U.S., particularly coal generation facilities. The most prominent environmental issue associated with electric generation is air pollutant emissions. Other important considerations include water use and discharge and solid waste production. These environmental issues are discussed below along with the environmental performance of IGCC.

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

2.31 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).[85] 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.[86]

IGGC 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.[87] 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 much 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 lower than the emissions produced by direct combustion of coal in PC boilers. IGCC plants also lend themselves to additional (90 percent+) cost effective mercury control through installation of mercury-specific syngas

[85] 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.

[86] 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.

[87] 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 new PC power plants and decrease plant efficiency because of their energy consumption.

clean-up processes and to relatively cost effective separation and capture of CO_2 to address climate change concerns.

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, these sulfur compounds are removed from the syngas through acid gas clean-up processes that remove 95 to 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.[88]

Table 2.4 illustrates the SO_2 emissions rates expected of new IGCC facilities and the rates of operating IGCC plants compared to New Source Performance Standards (NSPS) for coal power plants. The data illustrate that existing IGCC power plant SO_2 emissions rates are 11 percent to less than 2 percent of the NSPS requirement for coal power plants.

Table 2.4. IGCC Power Plant Particulate Emissions Performance

	SO_2 Emissions	
	lb/MWh	lb/mmBtu
Projected levels for new IGCC facilities[1]	0.11-0.7	0.013-0.08
Wabash operating levels[2]	1.08	0.13
Polk operating levels[2]	1.35	0.15
Willem Alexander operating levels[2]	0.44	0.05
Puertollano operating levels[2]	0.15	0.02
Coal power plant NSPS limits	NA	1.20

[1] Range based on estimates published in two separate studies. Low end of range based on: NETL/EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, Dec. 2002, Table 7-3, p. 7-9, illustrating emissions for Case 9A, IGCC F Class Turbine without CO_2 removal. Upper end of range based on: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table ES-1.

[2] Based on lb/MWh values reported in: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table 1-7, p. 1-26. Lb/mmBtu emissions rates calculated based on reported lb/MWh rates and plant heat rates.

[88] 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.

NOx Emissions

The acid gas clean-up processes in IGCC plants remove virtually all of the nitrogen compounds from the syngas. However, 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.[89] In IGCC plants, where the syngas delivered to the turbine is virtually nitrogen free, NOx formation is primarily the result of thermal NOx produced in the turbine combustor. Therefore, by maintaining a low fuel to air ratio (lean combustion) and adding a dilutent such as steam, the turbine flame temperature can be lowered and thermal NOx formation resulting from IGCC generation significantly reduced.[90]

Current state-of-the-art combustion control for syngas-fired turbines enables them to achieve NOx emissions as low as 15 ppm. At this level, they can exceed NSPS for coal power plants of 1.6 lb/MWh, or 0.15 lb/mmBtu (about 25 ppm for a gas turbine) without the use of post-combustion NOx controls such as selective catalytic reduction technology (SCR). However, 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. Because of the high flame speed of H_2 in syngas, use of this technology raises the risk of damaging flashbacks.[91]

Table 2.5 illustrates the NOx emissions rates expected of new IGCC facilities and the rates of operating IGCC plants compared to NSPS for coal power plants. The data illustrate that IGCC power plants are able to exceed NSPS for coal power plants without utilizing post-combustion NOx control.

[89] NETL, Major Environmental Aspects, p. 2-8.
[90] Id., p. 2-9.
[91] Id.

Table 2.5. IGCC Power Plant NOx Emissions Performance

	NOx Emissions	
	lb/MWh	lb/mmBtu
Projected levels for new IGCC facilities[1]	0.25--0.77	0.028--0.08
Wabash operating levels[2]	1.09	0.13
Polk operating levels[2]	0.86	0.09
Willem Alexander operating levels[2]	0.70	0.08
Puertollano operating levels[2]	0.88	0.11
Coal power plant NSPS limits	1.60	0.15

[1] Range based on estimates published in two separate studies. Low end of range based on: NETL/EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, Dec. 2002, Table 7-3, p. 7-9, illustrating emissions for Case 9A, IGCC F Class Turbine without CO_2 removal. Upper end of range based on: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table ES-1.

[2] Based on lb/MWh values reported in: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table 1-7, p. 1-26. Lb/mmBtu emissions rates calculated based on reported lb/MWh rates and plant heat rates.

To achieve even deeper NOx reductions at IGCC facilities, for instance to meet the NOx emissions levels required of some new natural gas combined cycle facilities of 2 or 3 ppm (0.01 lb/mmBtu), post combustion NOx control with SCR would be required. SCR is a commercially available technology in wide use on natural gas-fired CTs and coal boilers. However, to deploy SCR technology on IGCC facilities where syngas is the fuel, additional sulfur removal from the syngas is required (close to 100 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 the addition of a zinc oxide or activated carbon polishing reactor, but would substantially add to the cost of IGCC NOx control. DOE estimates indicate that the additional cost of deploying SCR with deep sulfur removal on IGCC would be $138/KW of capital and increase the cost of energy from an IGCC facility about 4 mills/kWh. None of the commercially demonstrated IGCC facilities operating today employs post-combustion SCR controls.[92]

[92] See detailed discussion at id., p. 2-39—2-41.

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 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.[93]

Table 2.6 illustrates the particulate emissions rates expected of new IGCC facilities and the rates of operating IGCC plants compared to NSPS for coal power plants. The data illustrate the low particulate emissions associated with IGCC power plants.

Table 2.6. IGCC Power Plant Particulate Emissions Performance

	Particulate Emissions (PM10, particulate, H_2SO_4 mist)	
	lb/MWh	lb/mmBtu
Projected levels for new IGCC facilities[1]	0.100	0.011
Wabash operating levels[2]	<0.100	<0.012
Polk operating levels[2]	<0.140	<0.015
Willem Alexander operating levels[2]	0.010	0.001
Puertollano operating levels[2]	0.044	0.005
Coal power plant NSPS limits	NA	0.030

[1] Based on estimates from: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002. Table ES-1.

[2] Based on lb/MWh values reported in: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table 1-7, p. 1-26. Lb/mmBtu emissions rates calculated based on reported lb/MWh rates and plant heat rates.

[93] Id., p. 2-7—2-8.

Mercury Emissions

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 United States. Power plant mercury emissions are currently unregulated, but EPA has proposed coal power plant mercury regulations that are scheduled to be finalized by December 2004 and would be implemented in the 2007-2010 timeframe.

Emission testing to date demonstrates that mercury emissions rates can vary considerably across both IGCC and PC power plants. However, the data indicate that IGCC plants operating without mercury-specific controls are probably no worse than PC plants that have particulate and SO_2 emission control technologies (e.g., ESP's, and flue gas desulfurization (FGD) systems, which produce mercury reduction co-benefits).[94]

Table 2.7 compares the mercury emissions rates of the two commercial electricity generation IGCC facilities in the U.S. to several PC plants with emissions controls. The table demonstrates the wide difference in mercury emissions across plants, but that the IGCC plants' performance is similar to the PC facilities, though slightly higher than the emissions rates of several of the PC facilities.

Table 2.7. IGCC Power Plant Mercury Emissions Performance.

	Plant Type	Size (MW)	Coal Type	Emissions Controls	Emissions Factor (lb/mmBtu)	Emissions Factor (lb/MWh)
Polk	IGCC	250	Bituminous	Syngas cleanup	5.2	4.8×10^{-5}
Wabash	IGCC	262	Midwest Bituminous	Syngas cleanup	4.4	6.1×10^{-5}
Widows Creek 6	PC—dry bottom wall-fired	140	Eastern Bituminous	hot-side ESP, low NOx burners	0.69	6.5×10^{-6}
Bailly 7 & 8	PC—wet bottom cyclone fired	160 & 320	Bituminous & Subbituminous	cold-side ESP, wet limestone FGD	2.23	2.4×10^{-5}
Big Bend 3	PC–Dry bottom, opposed wall-fired	445	Illinois Bituminous	Cold-side ESP, low NOx burners, wet limestone FGD	1.75	1.6×10^{-5}
Lawrence 4	PC—dry bottom tangential-fired	115	Western Subbituminous	Wet veturi scrubber, wet limestone FGD	4.9	5×10^{-5}

Source: NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies, Dec. 2002, Table 2-15, p. 2-31–2-32.

[94] NETL, Major Environmental Aspects, p. 2-31.

Where IGCC power plants have a distinct advantage over PC power plants is in the cost effectiveness and effectiveness of further mercury control. 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.[95] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (up to 99 percent) mercury control with established technology.[96]

The most cost-effective approach for IGCC mercury control is to treat the syngas prior to combustion to take advantage of the greater concentration of mercury, lower mass flow rate, and high pressure. Several technologies are commercially available for removing mercury from syngas using sorbents such as activated carbon that have been used successfully at gasification facilities to remove 90-95 percent of mercury. Eastman Chemical operates a ChevronTexaco gasifer at its Kingsport, Tennessee facility that utilizes activated carbon-based technology to achieve 90-95 percent mercury removal.[97] Although mercury removal beyond 95 percent has not been demonstrated with syngas, there is commercial experience removing virtually all (99.99 percent) of the mercury from natural gas. Because the mercury concentrations of untreated natural gas cleaned to this level are similar to that in syngas, it is believed that comparable results would be possible using similar technology for IGCC applications.[98]

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 would be about 0.25 mills/kWh, or about $3,500 per pound of mercury removal.[99] This is about 10 times less than 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.[100]

Carbon Dioxide Emissions

Another significant environmental advantage of IGCC is the potential for relatively cost-effective improvement in CO_2 emissions performance. CO_2 is a greenhouse gas that is linked to global climate change concerns. Because coal is a carbon intensive fuel, coal power plants emit significant quantities of CO_2. Power plant CO_2 emissions are not currently regulated in the U.S., but domestic and international pressure to address climate change concerns may lead to future regulation.

IGCC technology has three advantages over PC power plants for addressing CO_2 emissions. First, IGCC facilities have the ability to operate at higher efficiencies than PC plants. Although current IGCC power plants typically operate with efficiencies that are

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[95] NETL, "The Cost of Mercury Removal in an IGCC Plant," Sept. 2002, p. 1.
[96] Id.
[97] Id., p. 5.
[98] Id.
[99] Id., p. 1-2.
[100] 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.

comparable to new PC plants (35-42 percent efficiency), there is very little room for further efficiency improvement with PC boilers, and the addition of more pollution controls will work against efficiency improvement. On the other hand, IGCC technology has not yet been commercially optimized and has many processes where efficiency could be improved, including turbine designs and improved integration of the turbine and ASU systems. The next generation of IGCC facilities is expected to achieve efficiencies around 40 percent and over the longer-term reach efficiencies of 45-50 percent. Greater efficiency means more electricity is produced for every ton of coal consumed and that fewer byproduct CO_2 emissions are produced per MWh of generation.

Second, IGCC technology offers the potential for separating and capturing CO_2 emissions to achieve emissions reductions more efficiently than combustion technologies. 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 requires adding shift reactors to the syngas treatment system after the particulate and sulfur removal processes, or using shift reactors and clean-up processes to remove CO_2 and sulfur compound simultaneously. These reactors are commercially available, but their use has not been commercially demonstrated on IGCC facilities for this purpose. 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.[101]

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 would be about 5 percent of net plant output, compared to 21 percent for NGCC and 28 percent for PC.[102] The second advantage is lower capital cost to deploy CO_2 capture technologies. The NETL/EPRI study estimates that CO_2 capture would increase 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.[103]

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

[101] NETL, Major Environmental Aspects, p. 2-45—2-47.
[102] Id., citing DOE—EPRI Report 1000316, Dec. 2000.
[103] Id.

1.70 cent/kWh. With current technology they found that the cost of energy from an IGCC with CO_2 capture would be 6.69 cents/kWh versus 7.71 cents/kWh for PC with CO_2 capture.[104]

Finally, 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. Furthermore, coal gasification can produce pure hydrogen, which can be used in fuel cells for electricity generation and to power fuel cell vehicles. IGCC technology deployment will support progress towards development and commercial optimization of technologies to meet future energy needs without threatening the global environment.

2.32 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.[105] 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 or construction backfill. 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.[106]

[104] Jeremy David and Howard Herzog, "The Cost of Carbon Capture." 2000.
[105] NETL, Major Environmental Aspects, p. 2-4—2-5.
[106] Id.

2.4 IGCC Economics and Operating Performance

IGCC is not perceived to be a mature technology with well-established costs and performance characteristics, or a standardized commercial design. Different gasifier technologies, IGCC design configurations and fuel feedstocks have different cost and efficiency characteristics. Therefore, 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. The discussion below reviews the basic cost components of IGCC power plants and summarizes a number of IGCC cost data and estimates.

2.41 Overnight Capital Costs

Overnight capital costs refer to the cost of erecting the plant, including construction contingencies, but not considering construction financing, or long-term financing costs. Typically, power plant developers hire an engineering firm to provide a cost bid for designing and building a power plant facility, which includes the firm's fees. Most studies that compare capital costs of different types of power plants refer to the overnight capitals costs 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).

Table 2.8 lists IGCC overnight capital cost and efficiency[107] data from the two operating IGCC demonstration facilities in the U.S. and estimates from several 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 wide range of IGCC costs and efficiencies across different studies and technologies. The overnight capital costs range from around $1,100/kW to over $1,700/kW and the efficiencies range from 32 percent to 45 percent.

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[107] 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.

Table 2.8. Selected Published IGCC Capital Costs and Plant Efficiencies

Demonstration Plants	Gasifier Technology	Overnight Capital Cost $/kW	Efficiency % (Btu/kWh HHV)
Wabash Generating Station[1]	Concophillips	1,680	40% (8,600)
Polk Power Station[2]	ChevronTexaco quench	1,790	37% (9,100)
Selected Published Estimates			
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[3]	ChevronTexaco quench	1,100	37% (9,300)
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[3]	Concophillips	1,140	39% (8,640)
EPRI Summary of Recent Study Results (2x7FA no spare gasifier) (2003)[3]	Shell	1,420	41% (8,370)
IEA/Foster Wheeler (2003)[4]	ChevronTexaco quench	1,187	36% (9,400)
IEA/Foster Wheeler (2003)[4]	Shell	1,371	41% (8,370)
Jacobs consultancy (No shift, no capture) (2003)[5]	ChevronTexaco quench	1,164	41% (8,384)
Jacobs consultancy (Shift, no capture) (2003)[5]	ChevronTexaco quench	1,169	39% (8,777)
EIA Annual Energy Outlook (2003 Assumptions)[6]	unspecified	1,367	43% (8,000)
NETL/EPRI Parsons Case 9A (E-Gas w/ F turbine) (2002)[7]	ConcoPhillips	1,070	40% (8,609)
NETL/EPRI Parsons Case 3B (E-Gas w/ H turbine) (2002)[7]	ConcoPhillips	1,262	43% (7,915)
David & Herzog Year 2000 Plant (2000)[8]	unspecified	1,401	40% (8,506)
David & Herzog Year 2012 Plant (2000)[8]	unspecified	1,145	45% (7,513)
EPRI Shell-HR output maximized, Illinois # 6 coal (1998)[9]	Shell	1,340	41% (8,225)
EPRI Shell-HR, output maximized Pittsburgh # 8 coal (1998)[9]	Shell	1,274	43% (7,881)
EPRI Texaco-HR, output maximized, Illinois # 6 coal (1998)[9]	ChevronTexaco with heat recovery	1,314	42% (8,214)
EPRI Texaco-HR, output maximized, Pittsburgh # 8 coal (1998)[9]	ChevronTexaco with heat recovery	1,247	42% (8,113)
EPRI Texaco-Q, output maximized, Illinois # 6 coal (1998)[9]	ChevronTexaco quench	1,201	35% (9,622)
EPRI Texaco-Q, output maximized, Pittsburgh # 8 coal (1998)[9]	ChevronTexaco quench	1,148	37% (9,316)
EPRI ConocoPhillips-HR, output maximized, Illinois # 6 coal (1998)[9]	ConcoPhillips	1,225	41% (8,248)
EPRI ConocoPhillips-HR, output maximized, Pittsburgh # 8 coal (1998)[9]	ConcoPhillips	1,171	42% (8,066)
Regulatory Filings			
SFA Pacific BACT Analysis of Prairie State (4 gasifiers)[10]	ChevronTexaco quench	1,795	32% (10,622)
SFA Pacific BACT Analysis of Prairie State (10 gasifiers)[10]	ChevronTexaco quench	1,516	32% (10,576)
SFA Pacific BACT Analysis of Prairie State (4 gasifiers)[10]	ConcoPhillips	1,876	36% (9,492)
SFA Pacific BACT Analysis of Prairie State (10 gasifiers)[10]	ConcoPhillips	1,584	36% (9,451)
WEPCO Elm Road Proposal[11]	ChevronTexaco 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] 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.
[4] 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.
[5] 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.
[6] EIA, Assumptions to the Annual Energy Outlook 2003, p. 73.
[7] 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.
[8] Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.
[9] 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.
[10] SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 35.
[11] Public Service Commission of Wisconsin and Department of Natural Resource, "Final Environmental Impact Statement. Elm Road Generating Station–Volume 1," July 2003, Chapter

Cost data from the existing IGCC plants in the U.S., Wabash and Polk, 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 may be indicative of the conservative approach taken by companies reviewing new technologies and may include plant specific costs. For example, in the case of the Prairie State filing, the costs reflect the intended use of coal with very high ash content.

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, because they can be gasified most efficiently and enable the production of the highest heating value syngas, which improves efficiency and reduces the required size (cost) of fuel handling and gasifier equipment. Table 2.9 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 in this assessment.

Table 2.9. Cost and Efficiency Estimates for ConcoPhillips Gasifier using Different Fuels

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).

An important issue in designing IGCC power plants for commercial operation is assuring that they operate with high availability.[108] To be viewed as a viable technology for commercial electricity generation, power plant technologies generally need to achieve availabilities around 90 percent.[109] Achieving this level of availability with current gasification technologies requires redundant gasifier capacity, which increases the cost of

[108] 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.

[109] 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."

IGCC facilities. Table 2-10 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 2.10. 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)
ChevronTexaco Quench	1,160–1,340	1,270
ChevronTexaco Heat recovery	1,400–1,500	1,450
ConocoPhillips	1,230–1,390	1,300
Shell	1,570–1,670	1,620

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.

The EPRI summary indicates that the cost of IGCC systems with a redundant gasifier is estimated to be between $1,160/kW and $1,670/kW, with the costs lowest for the ChevronTexaco 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.[110] Furthermore, Shell's technology, which does not require extended, planned outages for refractory replacement (an operating requirement for current ChevronTexaco and ConocoPhillips gasifiers) may be able to achieve high availabilities (but probably not 90 percent) without redundant gasifier capacity.[111]

[110] 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.
[111] Id.

Another important consideration in designing IGCC systems is the extent to which the design seeks to accommodate and reduce the cost of future CO_2 emissions reductions. Doing so could involve, for example, ensuring the plant footprint could handle the additional equipment required for capture, incorporating shift reactors into the gas clean-up processes, and evaluating the appropriate sizing of the ASU, coal handling and turbine equipment to optimize for operational changes that would be associated with beginning to capture CO_2 at the facility.[112]

Also critical in the cost of developing IGCC is whether a project is being developed on a greenfield site or is repowering of an existing coal or natural gas combined cycle facility. Virtually all cost estimates for IGCC assume a greenfield plant, but cost savings may be possible in repowering scenarios. Repowering of existing coal facilitates may allow developers to take advantage of existing coal handling, electricity interconnect and steam turbine facilities that would reduce the cost of the project. Likewise, repowering of an existing natural gas combined cycle facility, assuming there was ample space and coal delivery capability at the site, could enable a developer to utilize the existing combined cycle power block, which accounts for roughly 30 to 35 percent of IGCC capital costs.

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.

Costs and performance estimates for new PC power plants are generally less varied due to the considerable experience constructing and operating these facilities. Table 2.11 illustrates PC cost estimates from several studies. Table 2.11 illustrates that with the exception of the WEPC Elm Road Proposal, PC capital cost estimates range between \$1,022/kW and \$1,154/kW.

[112] 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.

Table 2.11. PC Capital Cost Estimates

	PC Overnight Capital Cost ($/kW)
EIA Annual Energy Outlook (2003 Assumptions)[1]	1,154
NETL/EPRI Parsons (2002)[2]	1,143
Herzog Year 2000 Plant (2000)[3]	1,150
Herzog Year 2012 Plant (2000)[3]	1,095
IEA (Stork Engineering, 1999)[4]	1,022
SFA Pacific BACT Analysis of Prairie State (2003) [5]	1,150
WEPCO Elm Road Proposal (2003)[6]	1,415

[1] EIA, Assumptions to the Annual Energy Outlook 2003, p. 73.

[2]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; PC case 7C.

[3]Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.

[4]IEA Greenhous Gas R&D Programme and Strok Engineering Consultancy, "Assessment of Leading Technology Options for Abatement of CO_2 Emissions," December 1999.

[5]SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 35.

[6]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.

2.42 Financing Costs

Overnight capital cost represents the cost of building a power plant without consideration of financing costs. However, financing costs (both construction financing and long-term financing) are a critical component of the overall cost of a coal power plant and can significantly impact the cost of energy produced from the plant.

Construction financing costs refer to the cost of equity and debt financing during the design and construction period, which for IGCC plants is typically about 4 years (about two years of actual construction). Construction financing costs are important because, unless they are recovered during the construction period (as cost of 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 for a coal power plant (IGCC or PC) add about 10 percent to the overnight capital cost.

The other financing cost is the cost of long-term financing for the plant. Long-term financing costs refer 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.[113] In regulated markets, typical after tax returns allowed for utilities are around 11.5 percent.[114] 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 generally sells for around 6.5 percent.[115]

Under a typical utility financing scenario, the pre-tax weighted cost of capital would be around 12 percent and long-term financing costs (i.e., equity return and debt interest) would account for about 75 percent of the total cost of financing a coal power plant project over 30 years. For example, if the total cost of a 600 MW IGCC plant, including overnight capital costs and construction financing was $1 billion, the total financed cost over 30 years (assuming the capital structure and cost just described) would be about $4 billion. About $3 billion of the $4 billion would be long-term financing costs over the 30 year period.

2.43 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 power plant. Fuel costs (on a cent/kWh of output basis) are a function of the price of the fuel and the efficiency of the power plant. More efficient coal plants use less fuel per kWh 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 should be similar for IGCC and PC for the next generation of IGCC. Assuming IGCC efficiency improves as the technology matures IGCC fuel costs should come down 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.

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113 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).)
114 Id.
115 Based on personal communications with Lehman Brothers.

2.44 Cost of Energy

Each of the costs discussed above, capital (overnight capital costs, construction financing, and long-term financing), fuel, and O&M costs add to the cost of producing energy from an IGCC (or other) power plant (cents/kWh). Calculating the cost of energy 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 financing costs, taxes, and depreciation. Most studies evaluating energy costs under traditional financing scenarios for coal power plants assume around a 15 percent levelized carrying charge for capital. For this analysis, the levelized carrying charge for capital has been calculated with assistance from Robert Williams of Princeton University by applying the EPRI Electric Supply Technical Assessment Guide (TAG) methodology as described in the June 1993 TAG report.[116] Table 2.12 illustrates the cost of energy associated with a number of representative IGCC power plants, all assuming the availability of redundant gasifier capacity to provide high plant availability.

Table 2.12 provides a Reference IGCC case, which the authors believe represents a reasonable middle ground estimate of the cost and performance characteristics of the next set of IGCC facilities that will be built. The Table 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.[117]

Table 2.13 illustrates cost of energy information for a series of NGCC and supercritical PC power plant scenarios. Representative 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 natural gas prices averaging $4.50/mmBtu.[118]

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[116] 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 3.4 below analyzes the cost of energy impacts of the 3Party Covenant).

[117] 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.

[118] 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 2.12. Cost of Energy Estimates for IGCC Power Plants under Traditional Financing

	IGCC Reference (2+1 gasifiers, ($1,400/kW; 85% CF; 39% Eff.)	IGCC 1 (2+1 gasifiers, $1,200/kW; 85% CF; 42% Eff.)	IGCC 2 (2+1 gasifiers, $1,400/kW; 75% CF; 39% Eff.)	IGCC 3 (2+1 gasifiers, $1,600/kW; 85% CF; 39% Eff.)	IGCC 4 ConocoPhil (2+1 gasifiers)	IGCC 5 Texaco Q (2+1 gasifiers)	IGCC 6 Texaco HR (2+1 gasifiers)	IGCC 7 Shell (2+1 gasifiers)
Design and Construction								
Plant Size (MW)	**550**	550	550	550	550	550	550	550
Total Plant Cost–EPC ($/kW)	**$1,400**	$1,200	$1,400	$1,600	$1,300	$1,270	$1,450	$1,620
Operation								
Fuel cost ($/mmBtu)	**$1.24**	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
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	8,750.00	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	4,095,300	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*	**15.7%**	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
Estimated Cost of Energy								
O&M (cent/kWh)	**0.80**	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Fuel (cent/kWh)	**1.08**	1.02	1.08	1.08	1.06	1.17	1.09	1.04
Capital (cent/kWh)	**2.95**	2.53	3.35	3.37	2.74	2.68	3.06	3.42
Cost of Energy (cent/kWh)	**4.83**	**4.35**	**5.22**	**5.25**	**4.60**	**4.65**	**4.94**	**5.25**

Table 2.13. 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; 85% CF; 50% Eff.)	PC Reference ($1,150/kW; 85% CF; 39% Eff.)	PC 1 ($1,100/kW 85% CF; 40% Eff.)	PC 2 ($1,200/kW; 85% CF 39% Eff.)	PC 3 ($1,300/kW; 85% CF 39% Eff.)
Design and Construction								
Plant Size (MW)	500	500	500	500	550	550	550	550
Total Plant Cost ($/kW)	$510	$510	$510	$510	$1,150	$1,100	$1,200	$1,300
Operation								
Fuel cost ($/mmBtu)	$4.50	$4.00	$4.50	$5.00	$1.24	$1.24	$1.24	$1.24
Plant Efficiency (%)	50%	50%	50%	50%	39%	40%	39%	39%
Heat Rate (Btu/kWh HHV)	6,800.00	6,800.00	6,800.00	6,800.00	8,700.00	8,500.00	8,700.00	8,700.00
Plant Capacity Factor (%)	50%	85%	85%	85%	85%	85%	85%	85%
Annual Generation (MWh)	2,190,000	3,723,000	3,723,000	3,723,000	4,095,300	4,095,300	4,095,300	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	15.5%	15.5%	15.5%	15.5%	15.7%	15.7%	15.7%	15.7%
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	3.40	1.08	1.05	1.08	1.08
Capital (cent/kWh)	1.81	1.06	1.06	1.06	2.42	2.32	2.53	2.74
Cost of Energy (cent/kWh)	5.12	4.03	4.37	4.71	4.30	4.17	4.41	4.62

3.0 3PARTY COVENANT FINANCING PROGRAM

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:

1. *Federal Loan Guarantee:* The program for implementing the 3Party Covenant would be established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee would include allowing for an 80/20 debt to equity financing structure and would 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.
2. *State PUC Approval Process:* States interested in participating in the program would voluntarily opt-in by adopting utility regulatory provisions for state PUC review and approval of IGCC project costs, which in some states would require legislative action to create appropriate enabling authority. Specifically, a state PUC (or other utility rate making authority in the case of public power), acting under state enabling authority, would agree 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 of the IGCC project, the Federal Energy Regulatory Commission (FERC) may also have a role.) The state PUC would provide 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, including cost of capital. The certification by the state PUC would occur up-front when the decision to proceed with the project was being made, and the prudence review by the state PUC and cost recovery would occur on an ongoing basis starting during construction, which would reduce the construction risks borne by the developer, avoid accrual of construction financing expenses, and protect ratepayers.
3. *Equity Investor*: The equity investor under the 3Party Covenant would be either an electric utility 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 would contribute equity for 20 percent of project costs and negotiate performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return would be 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 3.4 below, the approach would significantly reduce the cost of IGCC power, making it cost competitive with PC and natural gas combined cycle generation.

3.1 Objective of 3Party Covenant

The objective of the 3Party Covenant is to create a financing and regulatory structure that provides ready access to capital at lower cost in an environment that tolerates technology risk. In meeting this objective, the 3Party Covenant addresses fundamental economic and financial challenges inhibiting IGCC deployment. The program is designed to be a mechanism that could facilitate development of an initial fleet of commercial IGCC plants this decade to establish the technology and reduce costs. Fundamental challenges addressed by the 3Party Covenant include:

1. *Challenge:* Equity investors are unwilling to invest $750 million to build IGCC power plants.

   3Party Covenant: Equity investors requirement is reduced to 20 percent (from around 45 percent under traditional utility financing) through the terms of a non-recourse loan backed by a federal loan guarantee and an assured revenue stream approved by the state PUC that provides for a fixed equity return and repayment of debt.

2. *Challenge:* Equity investors are unable to raise attractive debt to finance IGCC.

   3Party Covenant: Provides federal loan guarantee with "AAA" credit rating backed by the full faith and credit of the United State government rather than relying on project risks or corporate credit.

3. *Challenge:* Significant construction and operating risk are associated with deploying new generation technology, particularly at the investment scale of IGCC.

   3Party Covenant: Requires an up-front state PUC process to approve a stream of revenues to cover return of capital, cost of capital, and operating costs through rate adjustment clauses—the construction and operating risks are thereby shifted to and spread across ratepayers based on state PUC finding that doing so is in the public interest.

4. *Challenge:* Market risks in deregulated wholesale electricity markets make large capital investments in deploying IGCC unattractive.

   3Party Covenant: Remove market risks, after state PUC review and approval, through state PUC assured revenue stream.

5. *Challenge:* Capital cost and resulting cost of energy are higher for IGCC versus PC for coal generation.

3Party Covenant: Reduces IGCC energy costs to levels below new PC energy costs through higher debt/equity ratio, lower cost of long-term debt, and minimizing of construction financing costs.

3.2 Roles and Perspectives of Three Parties

The 3Party Covenant works by structuring a financial arrangement between the federal government, state PUC, and equity investors. 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 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.

3.11 Federal Government

Authority for the federal loan guarantee would be established through federal legislation authorizing a loan guarantee to finance IGCC projects. The guarantee would pledge the full faith and credit of the United States Government and receive a "AAA" bond rating to backstop project debt financing. The legislation would establish a government loan guarantee administrator (presumably DOE) that would be 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 would provide a powerful incentive from the federal government that would encourage state PUC and equity investor participation.

The administrator would also set the financing terms and conditions of a federal loan guarantee for the debt financing. These terms would include a favorable 80/20 debt to equity structure and requirements for qualification. The most important condition for qualification would be state PUC certification and approval of the project and a final order that would ensure timely recovery of approved project costs, including cost of capital. These state PUC procedures would reduce the risk borne by the federal loan guarantee and would include procedures under which the state PUC would: (1) certify before construction begins that an IGCC project meets federal and state requirements; (2) periodically approve the prudence of each portion of the project as construction proceeds; and (3) provide strong assurance of timely cost recovery for each approved portion and, once the plant is completed, for recovery of approved cost of capital and operating costs.

In return for establishing the federal loan guarantee program, the federal government would receive the energy, national security, economic and environmental policy benefits of IGCC deployment and commercialization at low risk. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (FCRA). That FCRA makes commitments of federal loan guarantees contingent upon appropriations in the year the program is established of enough funds to cover the estimated present value cost associated with the guarantees, which is determined by the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors to make this determination. To the extent these 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 would be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, for example, then $5 billion worth of loan guarantees could be provided (enough for about 6 projects) with a federal budget impact of $500 million.

3.12 States

The 3Party Covenant is distinguished from other federal financing programs because a principal party is a state PUC, which effectively controls the revenue stream needed to service the federally guaranteed debt. The state PUC, operating under state enabling law, would review and approve the IGCC plant proposal upfront, determine the need for power, establish the mechanism for allocation of project risks and recovery of approved costs, conduct ongoing prudence review during construction and operation, and determine 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 would be entirely voluntary. The federal government would establish terms and conditions for receiving the federal loan guarantee, but there would be no requirement for any company or state to participate in the program.

The 3 Party Covenant requires states that want to participate to establish a state PUC review and approval process that would provide for cost recovery guarantees before financial commitments for a federal loan guarantee become effective. Traditionally, PUC prudence reviews occur after a project is completed, when the opportunity to address problems are limited. The 3Party Covenant requires up-front 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 laws. In some states there would be adequate authority under current law, and in some states additional legislative authority would be required (<u>see</u> detailed discussion of state PUC authority and precedent in Sections 5.0 and 6.0 below). 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 on-going 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 public benefits programs. In these instances, the non-bypassable charge is typically limited to specific purposes so new legislation most likely would be required to include recovery of costs from a new IGCC projects through a non-bypassable wire charge.

The availability of a federal loan guarantee under the 3Party Covenant would provide 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 would result in lower financing costs for an IGCC plant through lower interest rates and a higher debt-equity ratio that would reduce both the amount of higher cost equity in the capital structure and the associated income taxes. Consequently, a strong reason for state PUC participation would be 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 would have to weigh the potential savings against the construction and operating risks that would also be passed along to the ratepayers (See Section 3.3 below).

In addition, one concern of state PUCs is to maintain quality credit ratings of utilities under their jurisdiction. The availability of nonrecourse federally guaranteed financing would significantly reduce the pressure on the utility's capital resources.

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

The state PUC's participation would also help deploy an environmentally attractive technology. IGCC technology can cost effectively achieve 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.

3.13 Equity Investor

The equity investor under the 3PartyCovenant is likely to be either a utility or an independent power producer. The equity investor contributes equity for 20 percent of project costs and obtains performance guarantees to develop and construct the IGCC plant.

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, despite relatively lower risks, even in regulated environments over the past 10 years. The hypothesis of the 3Party Covenant is that only when many of these risks can be shifted to the federal loan guarantor (through nonrecourse financing) and the ratepayer (through assured cost recovery after up-front certification and prudence determinations) is it likely that IGCC projects will be financed during this decade.

3.2 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 plant cost recovery under the 3Party Covenant would be through an adjustment clause 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.[119]

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 would be 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.[120]

Within these constructs, the specific procedures that must be established by the state PUC for participation would need to include the following elements (see Section 6.0 below for a detailed discussion of these requirements and how they relate to existing state laws):

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[119] 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).)

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

1. Before any construction began, the state PUC would review 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 would include consideration of several factors concerning the likely benefits and costs of the proposed IGCC plant and the need for base load power. Based on satisfactory determination, the state PUC would issue a certificate of public convenience and necessity for the new plant. In the certificate, the state PUC would permanently establish the return on equity for the project and approve the use of an adjustment clause for future recovery of incurred costs (including recovery during construction, of cost of capital on construction work in progress (CWIP).

2. After issuance of a certificate and as construction progresses, the state PUC would periodically conduct a prudence review on an expedited basis and approve the portion of the IGCC plant constructed during the preceding period. As each portion of construction expenditures (CWIP) was approved in the ongoing review, the cost of capital for the approved expenditures would become recoverable on an ongoing basis through, and would be reflected in, the approved adjustment clause.

   The duration of each periodic (e.g., six-month) review proceeding would be limited (e.g., to three months). As a result, cost of capital during construction would be 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 would be recovered on an ongoing basis during construction, a much smaller amount would be 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 cost of capital) could not thereafter be challenged, in the absence of fraud or concealment. For example, issues concerning excessive cost, inadequate quality control, failure to complete, or inability to operate properly could not raised. In this way, the state PUC's review and protective approval would be updated during and after plant construction.

   Disbursement of the federally guaranteed loan would be coordinated with the ongoing review process. As each portion of construction expenditures was reviewed and approved for recovery through the adjustment clause, the federally guaranteed loan would be 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 would conduct on an expedited basis a prudence review of the plant's operating costs during the preceding period. As the operating costs were approved in the ongoing review, the approved operating costs become recoverable on an ongoing basis through, and would be 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 related cost of capital also become recoverable through, and would be reflected in, the approved adjustment clause. The state PUC would require the IGCC plant owner to handle separately the revenue stream from the approved adjustment clause and place the revenues in a segregated account that could only be used to pay project costs, including cost of capital.

Under these procedures, state PUC certification and approval would create an assured, dedicated revenue stream to cover the construction, operating, and market risks of the IGCC plant. 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 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.

3.3 Ratepayer Perspective

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 are taking on the construction, operating, and marketing risks of IGCC technology. It would be the responsibility of the state PUC, through a highly transparent and public process, to evaluate the prudence of the IGCC investment decisions, including the feasibility of technology application, before costs could be passed along to ratepayers.

The state PUC would first conduct a due-diligence certification process, through which it would publicly examine 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 issue. After commencement of plant construction and thereafter, the state PUC would conduct ongoing prudence reviews of construction and operating costs. State PUC certification and prudence reviews would protect ratepayers and would be the basis for the state PUC determining whether to approve recovery of project costs.

After construction expenditures were determined to be prudent, they would be included in rate base and project risks would then be shifted to ratepayers. Laws in some states with more traditional regulation of electricity retail sales (e.g., Indiana) allow for this type of assured recovery for "clean coal technology" investments. The 3Party Covenant mirrors the Indiana law in this regard, with the entire IGCC plant treated as a clean coal technology investment.

First time commercial scale application of an advanced technology like IGCC has undeniable technology and operational risks. Under the 3Party Covenant, after state PUC review and approval of costs, these risks would be borne primarily by ratepayers. 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. The utility investor receives, under the pass-through procedures, an assured rate of return on investment but may incur other risks in the event the plant fails to operate as projected, such as unreimbursed purchase power costs to make up the shortfall. It should be noted that there are also substantial 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 vs. IGCC plants.

3.4 Cost of Energy Impact of 3Party Covenant

The 3Party Covenant program would reduce the cost of energy from an IGCC power plant 19-22 percent. The cost of energy reductions would result from:

1. Funding construction financing costs on a current basis (adding Construction Work in Progress (CWIP) to the rate base), rather than accruing these costs that typically account for about 10 percent of total plant investment by allowing them to be added to the rate base as incurred.
2. Lowering the cost of debt through the federal loan guarantee, which would reduce the interest charge from a typical 6.5 percent for a mid-grade utility bond in January 2003 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. Providing for a significantly higher ratio of debt to equity, which would move from a typical utility 55/45 ratio to 80/20 under the 3Party Covenant. The higher ratio would result in the replacement of 19 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 about 25 percent of project costs.[121]

These changes would reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant from about 12 percent (traditional utility financing) to 8 percent (3Party Covenant), reduce the cost of capital component of energy costs by 34 percent, and reduce the total energy cost 19-22 percent.

The impact of the 3Party Covenant can be demonstrated by comparing plants financed traditionally with plants financed under the 3Party Covenant. Table 3.1 illustrates cost of energy estimates under a 3Party Covenant financing for the IGCC Reference plant and alternative IGCC plants presented under traditional financing in Table 2.12 above. Table

[121] This assumption is somewhat more conservative than the recent 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.

3.1 illustrates the 19 to 22 percent reduction in energy costs across the plants under a 3Party Covenant financing program versus traditional utility financing.

A comparison also can be made of IGCC plants financed under the 3Party Covenant that have equivalent energy costs to the Reference PC plant illustrated in Table 2.13. The reference PC plant has an overnight capital cost of $1,150/kW and produces electricity at 4.3 cents/kWh. A hypothetical IGCC plant financed under the 3Party Covenant could have an overnight capital cost as high as $1,735/kW and still produce electricity at the same 4.3 cents/kWh. Alternatively, a hypothetical IGCC plant might only cost $1,400/kW, but operate less (due to a lower availability) than the 85 percent capacity factor assumed for the reference PC plant. If financed under the 3Party Covenant, a $1,400/kW IGCC could operate at only a 69 percent capacity factor and still produce electricity for the same 4.3 cents/kWh as the reference PC plant. These examples demonstrate that the 3Pary Covenant can make up for almost $600/kW of capital cost differential, or a combination of a substantially higher capital cost ($250/kW) and significant capacity factor reduction (from 85 to 69 percent).

Table 3.2 compares the cost of energy estimates for the Reference IGCC plant under the 3Party Covenant to the cost of energy estimates for the Reference PC, NGCC and IGCC plants under traditional utility financing scenarios. The table illustrates that the reference IGCC plant has a higher overnight capital cost than the Reference PC or NGCC under traditional financing, but when the Reference IGCC plant is financed under the 3Party Covenant, its energy cost is 11 percent less than the Reference PC and 25 percent less than the Reference NGCC. Figure 3.1 demonstrates these results graphically.

Table 3.1. Cost of Energy Estimates for IGCC Power Plant Scenarios under 3Party Covenant Financing

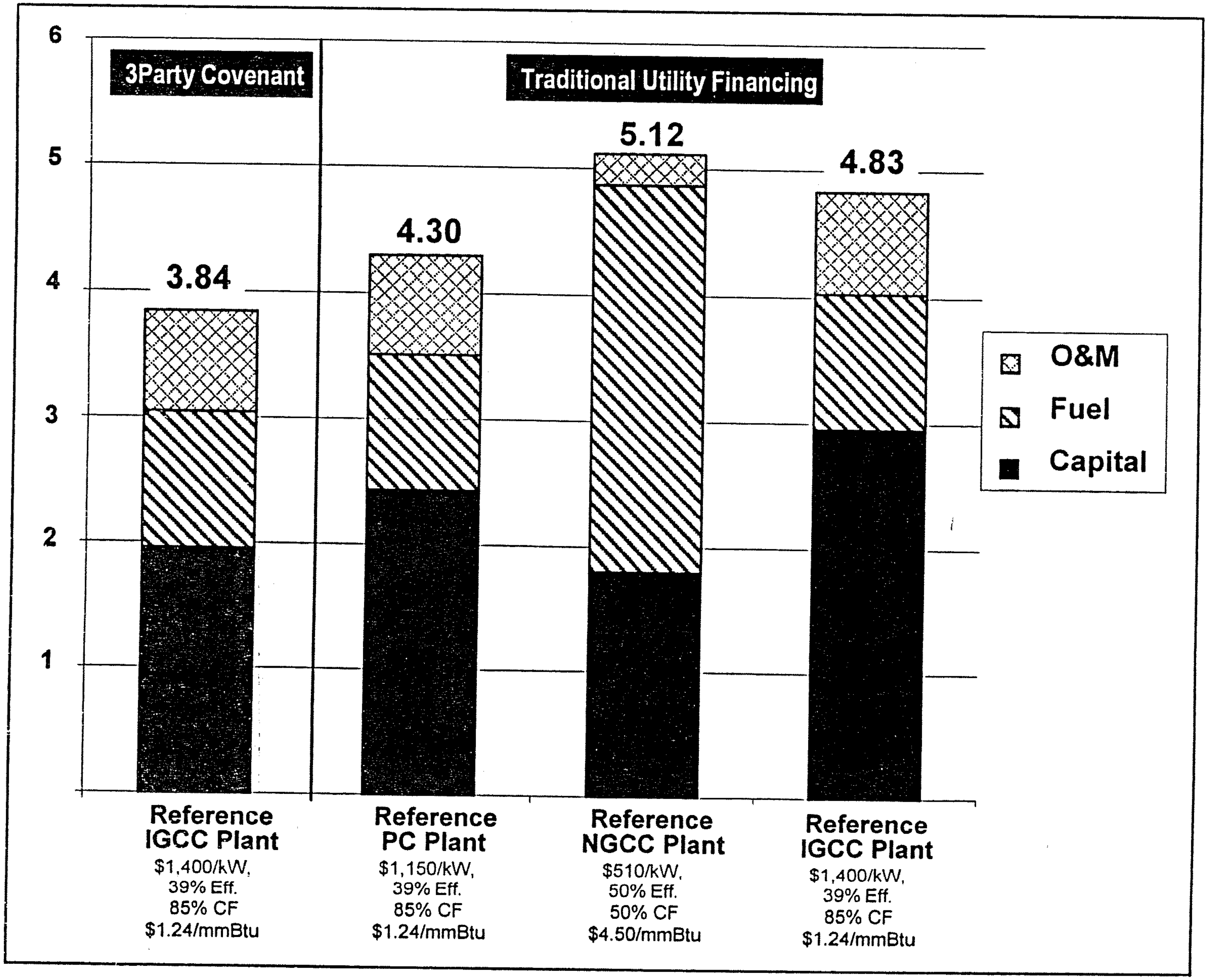
	IGCC Reference (2+1 gasifiers, ($1,400/kW; 85% CF; 39% Eff.)	IGCC 1 (2+1 gasifiers, $1,200/kW; 85% CF; 42% Eff.)	IGCC 2 (2+1 gasifiers, $1,400/kW; 75% CF; 39% Eff.)	IGCC 3 (2+1 gasifiers, $1,600/kW; 85% CF; 39% Eff.)	IGCC 4 ConocoPhil (2+1 gasifiers)	IGCC 5 Texaco Q (2+1 gasifiers)	IGCC 6 Texaco HR (2+1 gasifiers)	IGCC 7 Shell (2+1 gasifiers)
Design and Construction								
Plant Size (MW)	**550**	550	550	550	550	550	550	550
Total Plant Investment ($/kW)	**$1,400**	$1,200	$1,400	$1,600	$1,300	$1,270	$1,450	$1,620
Operation								
Fuel cost ($/mmBtu)	**$1.24**	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
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	8,750.00	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	4,095,300	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*	**10.4%**	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
Estimated Cost of Energy								
O&M (cent/kWh)	**0.80**	0.79	0.80	0.80	0.80	0.80	0.80	0.80
Fuel (cent/kWh)	**1.08**	1.017	1.08	1.08	1.06	1.17	1.09	1.04
Capital (cent/kWh)	**1.96**	1.68	2.22	2.24	1.82	1.78	2.03	2.26
Cost of Energy (cent/kWh)	**3.84**	**3.48**	**4.10**	**4.12**	**3.68**	**3.75**	**3.91**	**4.10**

Comparison to Cost of Energy under Traditional Financing								
Cost of Energy (cent/kWh) under Traditional Financing	**4.83**	**4.35**	**5.22**	**5.25**	**4.60**	**4.65**	**4.94**	**5.25**
Percent Reduction under 3Party Covenant	**21%**	**20%**	**22%**	**22%**	**20%**	**19%**	**21%**	**22%**

Table 3.2. Cost of Energy Comparison of Reference PC and NGCC Plants Financed Traditionally to Reference IGCC Plant Financed with 3Party Covenant

	Traditional Utility Financing			3Party Covenant
	IGCC (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)	NGCC ($4.50 gas; 50% CF; 50% Eff.)	PC ($1,150/kW; 85% CF; 39% Eff.)	IGCC (2+1 gasifiers, ($1,400/kW; 85% CF 39% Eff.)
Design and Construction				
Plant Size (MW)	550	500	550	550
Total Plant Cost ($/kW)	$1,400	$510	$1,150	$1,400
Interest During Construction (CWIP*) ($/Kw)	$168	$19	$138	0*
Total Plant Investment ($/kW)	$1,568	$529	$1,288	$1,400
Operation				
Fuel cost ($/mmBtu)	$1.24	$4.50	$1.24	$1.24
Plant Efficiency (%)	39%	50%	39%	39%
Heat Rate (Btu/kWh HHV)	8,700.00	6,800.00	8,700.00	8,700.00
Plant Capacity Factor (%)	85%	50%	85%	85%
Annual Generation (MWh)	4,095,300	2,190,000	4,095,300	4,095,300
Financing				
Percentage Debt	55%	55%	55%	80%
Debt Interest Rate	6.5%	6.5%	6.5%	5.5%
Percent Equity	45.0%	45.0%	45.0%	20.0%
After tax Equity Return	11.5%	11.5%	11.5%	11.5%
Tax rate (Federal & State)	38.2%	38.2%	38.2%	38.2%
Pre-tax Equity Return	18.6%	18.6%	18.6%	18.6%
Pre-tax WACC	11.9%	11.9%	11.9%	8.1%
Levelized Carrying Charge	15.7%	15.5%	15.7%	10.4%
Estimated Cost of Energy				
O&M (cent/kWh)	0.80	0.25	0.80	0.80
Fuel (cent/kWh)	1.08	3.06	1.08	1.08
Capital (cent/kWh)	2.95	1.81	2.42	1.96
Cost of Energy (cent/kWh)	**4.83**	**5.12**	**4.30**	**3.84**

Figure 3.1. Cost of Energy Comparison between Reference IGCC, PC and NGCC plants



4.0 TRADITIONAL ELECTRIC INDUSTRY STRUCTURE AND REGULATORY SYSTEM AND EFFECT ON ALLOCATION OF INVESTMENT RISK OF NEW IGCC PLANTS.

4.1 Description of traditional electric industry structure and regulatory system

What follows is a summary description of the traditional structure of the electric industry and the traditional approach to regulation of electric utilities. As discussed below, this structure and regulatory approach are currently applicable in many, but not all, states. In some states and in varying degrees, the electric industry has been restructured and competition has been introduced for retail electricity generation and sales. Section 5.0 below discusses in detail the regulatory systems in four states, two with more traditional regulatory regimes and two with retail competition. Included in that discussion are detailed citations to judicial and administrative decisions that support the more summary discussion in this Section 4.0.

The purpose of discussing state traditional regulatory regimes and competitive regimes is to develop an understanding of the effect that these regimes have on the allocation of electricity-generation investment risk among investors and ratepayers and to examine the legal authority and precedents for allocating such risk.

4.11. Treatment of Companies as Natural Monopolies.

The business of generating, transmitting, and distributing electricity to the public has traditionally been regarded as a natural monopoly. Generation, transmission, and distribution were believed to be most efficiently provided by a single company that was the sole provider of these services for the public in an assigned geographic area.

Under this approach, a state grants a single company the exclusive right to sell and distribute electricity to consumers in a specified service area and requires that company to undertake the obligation to meet the electricity needs of all such consumers, including both existing and future consumers. The corporate structure of the company can vary. For example, there may be a single corporation handling all of these activities for a given service area or a parent (or holding) company with subsidiary operating companies, each of which handles generation, transmission, and distribution within a particular service area.

While the states generally regulate (through state PUCs) the generation, retail sale, and distribution of electricity by utilities, interstate transmission of electricity and interstate sale of electricity for resale are regulated at the federal level under the Federal Power Act by the FERC. See 16 U.S.C. 791a-828e; Connecticut Light and Power Co. v. Federal Power Commission, 324 U.S. 515 (1945) (holding that Federal Power Commission, predecessor to Federal Energy Regulatory Commission (FERC) does not have jurisdiction over facilities used in local distribution); and Northern States Power v. Federal Energy Regulatory Commission, 176 F.3d 1090 (D.C. Cir. 1999) (holding that FERC exceeded its jurisdiction in requiring utility to curtail provision of electricity to its retail and its wholesale customers on the same pro rata basis). For example, where one company purchases electricity from another company generating the electricity and sells the purchased electricity to consumers, the initial purchase for resale (including any underlying power purchase contract) is generally subject to FERC jurisdiction, including rate review.[122] (The pass-through of costs by the purchasing company to consumers is generally subject to state PUC jurisdiction.) Because the transmission and distribution system in the portion of Texas in the Electric Reliability Council of Texas (ERCOT) region of the North American Electric Reliability Council (NERC) has very limited interconnections with transmission and distribution systems in contiguous states, the FERC lacks jurisdiction over transmission and sales for resale in that portion of Texas. See Public Utility Commission v. Utility Public Service Board of San Antonio, 53 S.W.3d 310, 312 (Tex. Sup. Ct. 2001).

4.12. Just and reasonable rates.

Because of the monopoly status of the utility, utility regulatory commissions (whether federal or State) are generally required by statute, as interpreted by the courts, to set rates that are "just and reasonable." The U.S. Supreme Court explained this requirement as follows:

[T] he fixing of 'just and reasonable' rates involves a balancing of the investor and consumer interests...[T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business...[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. Federal Power Commission v. Hope Natural Gas Co. (FPC v. Hope), 320 U.S. 591, 603 (1944).

See also Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679, 692-93 (1923) (holding that rates must permit a public utility to "earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other

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[122] In exercising its jurisdiction over sales for resale, the FERC generally requires public utilities making such sales to charge either cost-based rates or rates based on a competitive electricity market. See Section 6.3 below. In exercising its jurisdiction over interstate transmission, the FERC generally requires public utilities that own, control, or operate facilities used for transmitting electricity in interstate commerce to have on file open access nondiscriminatory transmission tariffs. See, e.g., Order No. 888, 61 Fed. Reg. 21,540 (1996).

business undertaking which are attended by corresponding risks and uncertainties"); and Duquesne Light Co. v. Barash, 488 U.S. 299, 316 (1989) (explaining that "just and reasonable" rates must balance the interests of investors and consumers). This requirement for "just and reasonable" rates is generally grounded in the constitutional bar against confiscatory taking of private property. See id. at 307.

Aside from this general standard, utility regulatory commissions are "not bound to the use of any single formula or combination of formulae in determining rates...[I]t is the result reached not the method employed which is controlling." FPC v. Hope, 320 U.S. at 602. Moreover, due to the economic complexity of the ratemaking process, there is no single "just and reasonable" rate. Instead, there is a "zone of reasonableness" within which the rate must be set. Federal Power Commission v. Conway, 426 U.S. 271, 278 (1976); see also Permian Basin Area Rate Cases, 390 U.S. 747, 770 (1968) and Montana-Dakota Co. v. Northwestern Public Service Co., 341 U.S. 246, 251 (1951).

This emphasis by the Court on "end results" changed the focus of the ratemaking process. For example, before FPC v. Hope, much attention was paid to whether the property on which investors must be allowed to receive a return should be valued at the original cost or the reproduction cost of the property. See, e.g., Smyth v. Ames, 169 U.S. 466, 546 (1898) (requiring receipt of "fair value" of the property); McCardle v. Indianapolis Water Co. ,272 U.S. 400 (1925) (requiring receipt of fair return on reproduction costs of property); Mississippi ex re. Southwestern Bell Telephone Co. v. Mississippi Public Service Commission, 262 U.S. 276, 291 (1923) (requiring fair return on prudent investment); and Dusquesne Light, 488 U.S. at 308-10 (explaining effect of FPC v. Hope.). After FPC v. Hope, none of these specific approaches was constitutionally required, and, in fact, some utility regulatory commissions consider multiple approaches to property valuation in setting just and reasonable rates.

4.13. Cost-of-service ratemaking.

In setting just and reasonable rates under traditional utility regulation, utility regulatory commissions traditionally apply a cost-of-service analysis. Under this approach, rates are set so as to allow the company to earn total revenues sufficient to cover the cost of service approved by the utility regulatory commission. The cost of service includes: return of (through depreciation and amortization) and return on the company's capital investment (which is referred to as the "rate base") related to electric service; and the company's operating expenses related to such service. For purposes of establishing the cost of service, the utility regulatory commission initially selects a representative test period, often the twelve months just before initiation of the rate review. See NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327, 1338 (D.C. Cir. 1981), cert. den. sub nom. New England Power Co. v. FERC, 457 U.S. 1117 (1982) (discussing use of two test periods, i.e., the most recent 12 months and the subsequent projected 12 months). The levels of capital investment, costs of capital, and operating expenses in the test period are evaluated by the utility regulatory commission and provide a starting point for determining what levels should be included in the cost of service and covered by the rates. The levels in the test period may be adjusted to the extent that they are determined to be unrepresentative of the future (e.g., are unlikely to continue) or to be unreasonable. See Energy Industrial Center Study, Dow Chemical Co., Environmental Research Institute of Michigan, Townsend-Greenspan and Co., Inc., and Cravath, Swaine and Moore at 334-40 and 378-85 (National Science Foundation June 1975) (generally describing cost-of-service ratemaking).

Costs related to capital.

Specifically, with regard to capital investments, the utility regulatory commission determines which investments should be included in the rate base and, if so, in what dollar amount. In general, investments are included in the rate base to the extent that they were prudent at the time that they were made and are used and useful (i.e., are actually used and are not superfluous) in providing electric service. See Jonathan A. Lesser, "The Used and Useful Test: Implications for a Restructured Electric Industry," 23 Energy Law Journal 349, 352 (2002).

However, the extent to which investments were prudent when made and to which they are used and useful in providing electric service may not be coincident. For example, while a company might prudently decide to invest in a new electricity generating plant based on then-current projections of electricity demand and planning and construction costs, the plant might be cancelled before completion because of changes in projected or actual demand or construction costs. Depending at least in part on the applicable underlying statutory authority for setting rates, utility regulatory commissions take various approaches to addressing plant cancellations.

One approach (referred to as the "prudent investment" test) is to include in rate base electricity generating plant investments that were prudent when made, regardless of whether the plant is ultimately completed and used. See William J. Baumol and J. Gregory Sidak, "The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?", 23 Energy Law Journal 383, 391-93 (2002). Review to determine whether an investment was prudent is generally conducted after plant construction is completed or terminated.

A second approach (referred to as the "used and useful" test) is to include in rate base only electricity generating plant investments that both were prudent when made and become used and useful. Under this approach, the utility regulatory commission reviews the investment decision with the benefit of some hindsight, i.e., the benefit of information that was not available when the investment decision was made. See id. The review is necessarily conducted after plant construction is completed and the plant is operating or after plant construction is terminated. In some cases, when applying the used and useful test, utility regulatory commissions both exclude investment that is not "used and useful" from rate base and deny any recovery of the investment principal. See, e.g., Pacific Power and Light Co. v. Public Service Commission, 677 P.2d 799, 805-6 (Wyo. Sup. Ct. 1984) (holding that cancelled nuclear plant is not used and useful property and so plant costs are not recoverable through inclusion in rate base or as operating costs and that costs may otherwise be recoverable if plant was reviewed and approved by Public Service Commission before commencement). In other cases, the utility regulatory commissions exclude the investment from rate base and allow amortization, and thus recovery, of the investment principal (but not cost of capital). See, e.g., Dusquesne Light, 488 U.S. at 310-12 n.7; Violet v. FERC, 800 F.2d 280 (1st Cir. 1986); and NEPCO Municipal Rate Committee, 668 F.2d at 1332-33 (stating that, while "general rule" is that only "used and useful" investments are included in rate base, FERC may use any method of valuing rate base as long as result is not "unjust or unreasonable" and upholding amortization of costs of cancelled plant and exclusion of such costs from rate base). But see Jersey Central Power & Light Co. v. FERC, 810 F.2d 1168, 1175-76 (D.C. Cir. 1987) (explaining that "use and useful" requirement is not constitutionally based and remanding to FERC to determine whether costs of cancelled nuclear plant should be included in rate base).

Under a third approach (referred to as the "economic used and useful" test), which is much less frequently used, the utility regulatory commission not only includes in rate base plant that was prudent to build and that was initially used and useful but also considers whether to continue to allow the plant in rate base in light of ongoing economic changes. Review continues even after the plant is completed and operating. The plant continues to be in the rate base only if the utility regulatory commission finds that the plant continues to be the most economic alternative for the company. See Jonathan A. Lesser, 23 Energy Law Journal at 359-63.

The "prudent investment," "used and useful," and "economic used and useful" tests represent the spectrum of approaches used by utility regulatory commissions to addressing recovery of capital (and related cost of capital) in electricity generating plants after plant construction is completed or terminated. Depending on the technology and size of an electricity generating plant, design and construction may extend over multiple months or years. Consequently, utility regulatory commissions have also considered how to treat preconstruction and construction costs during plant construction. Some utility regulatory commissions allow design and construction costs ("construction work in progress" or "CWIP") to be added periodically to the rate base, during construction until the plant goes into service. In contrast, some utility regulatory commissions do not allow any design and construction costs in the rate base until the plant is completed and is in use. The cost of capital during the construction period ("allowance for funds during construction" or "AFUDC") accrues, and must be carried by the investors, until the plant becomes "used and useful" and is added to the rate base. At that point, the total accrued cost of capital during construction is added to the rate base, along with the design and construction costs of the plant. See Cities for Fair Utility Rates v. Public Utilities Commission, 924 S.W.2d 933, 935-36 (Tex. Sup. Ct. 1996).

Once the rate base is established, the utility regulatory commission must determine a reasonable level for cost of capital (also referred to as "return on capital"). The cost of capital reflects the anticipated return and risks to the investors providing the capital for the company and varies depending on the manner in which the capital is obtained, e.g., on whether the capital is obtained through the sale to investors of common stock, preferred stock, or long-term debt. Long-term debt may be unsecured (i.e., based on the overall credit of the company issuing the debt), secured (i.e., based on the overall credit of the company and on a mortgage lien on specified assets of the company), or project-financed (i.e., nonrecourse to the company and based on a mortgage on the specific project for which the debt proceeds are used). In general, interest on long-term debt must be paid before dividends on common or preferred stock, and in the event of bankruptcy, debt holders must be paid off before shareholders. Consequently, long-term debt is considered a less risky form of investment. Moreover, preferred stock is considered less risky than common stock because the preferred stock specifies the level of the dividends, payment of such dividends has priority over payment of dividends on common stock, and preferred stock generally outranks common stock in bankruptcy. See Energy Industrial Center Study at 432-44 (discussing the distinctions between debt and equity and the limitations on issuance of debt).

The utility regulatory commission must determine what capital structure (i.e., what proportions of common stock, preferred stock, and long term debt), and what costs of common stock, preferred stock, and long-term debt, to use in determining the company's cost of capital. Generally, utility regulatory commissions use the company's actual capital structure during the test period and determine the cost of long-term debt and preferred stock by looking at the average, actual cost of existing debt and preferred stock. The cost of common stock is generally determined by evaluating the return currently required by prospective purchasers of common stock, and various methodologies are used to estimate currently required return. However, utility regulatory commissions sometimes assume a hypothetical "optimal" (i.e., least cost) capital structure for the company and determine the costs of common stock, preferred stock, and long-term debt based on that capital structure. See, e.g., Northern Carolina Utilities v. FERC, 42 F.3d 659 (D.C. Cir. 1994); and Southern Bell Telephone Co v. Louisiana Public Service Commission, 118 So. 2d 372, 380-82 (1960).

In addition to covering return on capital, cost-of-service rates also cover return of capital (i.e., depreciation or amortization of the company's capital investments). The utility regulatory commission must determine the number of years over which capital investments are depreciated or amortized for purposes of setting rates.

Costs related to operation.

Cost-of-service rates also cover the company's operating costs. Operating costs include operation and maintenance, fuel and of purchased power, salaries, and taxes. Coverage of these costs, of course, may affect investors' return on capital since these costs generally must be paid before any return on equity is actually realized. As in the case of cost of capital, utility regulatory commissions generally use actual operating costs during the test period as a starting point. Test period operating costs may be adjusted in order to ensure that they are representative of future operations. These costs may also be reviewed to determined whether they are reasonable and reasonably related to electric service and disallowed if they are not. Generally, operating costs may be disallowed based on evidence of insufficient relationship to electric service or of inefficiency, improvidence, or negligence on the part of the company and not simply based on the utility regulatory commission substituting its judgment for that of the company management. See, e.g., Indiana Gas Co. Inc. v. Office of Utility Consumer Counselor, 675 N.E.2d 739, 744 (Ind. App. 1997).

Rates are not constantly updated, but generally stay in effect until the company requests and is allowed to charge new rates or the utility regulatory commission initiates and completes a review of the existing rates. In some cases, rates requested by the company are suspended for a period to time, after which they may be charged subject to review and refund; in other cases, requested rates cannot go in effect at all until after regulatory review is completed. Moreover, whether initiated by the company or the utility regulatory commission, the ratemaking process takes a while to complete, and the test-period cost data on which final rates are based may become outdated. As a result, rates may stay in effect for significant periods of time, and there may be a significant lag between changes in operating costs, or, for that matter, cost of capital, and changes in rates to reflect such changes in costs. Depending on whether costs are increasing or decreasing in between ratemaking proceedings, this lag due to rate regulation may be to the benefit or the detriment of investors. The degree of regulatory lag is reduced to the extent that rate changes go into effect subject to refund.

In order to reduce the effect of regulatory lag and achieve a closer match of some revenues and costs, utility regulatory commissions often allow certain operating costs (e.g., fuel costs and purchased power costs) to be included in rates through a formula that reflects ongoing changes in these costs, rather than at a fixed level based on test period costs. Under that approach, a portion of the rates (e.g., fuel or purchased power costs) for a given future period (e.g., the next quarter) is paid by each customer as an estimated per-kilowatthour charge calculated using recent costs and projected kilowatthours of electricity sales. In addition, the per-kilowatthour charge reflects an adjustment to correct for any difference between the recent and actual costs for the immediately prior period (e.g., the prior quarter) and any difference between projected and actual electricity sales for that period.

4.2. Effect on allocation of electricity generation investment risk.

What follows is a qualitative analysis of the effect of the traditional regulatory system on the allocation of the risk of investment in new electricity generating projects (such as new IGCC plants). For purposes of this qualitative analysis, it is useful to subcategorize investment risk into construction risk, operating risk, and marketing risk. "Construction risk" is defined as the risk that the project construction will not be completed. "Operating risk" is defined as the risk that the completed project will not achieve operational benchmarks, e.g., a certain level of plant availability. Both construction and operating risk reflect, at least in part, the technology risk of the type of plant involved. "Marketing risk" is defined as the risk that the electricity generated by the completed, operating project will not be sold at prices that cover capital and operating costs of the project.

4.21. Construction and operating risk

The inability to complete or operate a new electricity generating plant threatens the recovery of the capital investment in, and related cost of capital of, the plant. The allocation of construction and operating risk is particularly important for IGCC plants because they use a capital-intensive technology with which there is relatively limited commercial-scale experience.

When the new plant is owned by a company subject to traditional utility regulation, the allocation of construction and operating risk associated with the plant depends largely on the utility regulatory commission's approach to setting, for purposes of cost-of-service ratemaking, the rate base used in determining return of and on capital. As discussed above, utility regulatory commissions use various approaches in determining rate base.

Under the "prudent investment" approach of including, in rate base, electricity generating plant investment that is prudent when made, regardless of whether the plant is ultimately completed and used, investors bear the risk that the decision to invest some or all of the capital involved may be determined by the utility regulatory commission to be imprudent. Ratepayers bear the risk that the plant, which was prudent at the time of the investment decision, may not be completed due to factors arising after such investment decision or, if completed, may not meet operational benchmarks. Ratepayers also bear the risk of cost overruns where a plant that was prudent to construct at the time of the investment turns out to cost more than initially projected, if the increased costs are determined to be reasonable. The timing of the utility regulatory commission's prudence review relative to the timing of the investment determines when risk is shifted to ratepayers. Generally, the review -- and so the shifting of risk to ratepayers -- occurs after plant construction is completed or terminated.

To the extent that the utility regulatory commission allows preconstruction and construction costs for prudent projects to be included (as "construction work in progress" or "CWIP") in the rate base before plant completion, there is further allocation of some construction and operating risk to ratepayers and the shifting of risk to ratepayers occurs sooner. This is because investors' recovery of construction costs from ratepayers begins earlier and the investors' need for construction loans is reduced. It should be noted that, because of the earlier recovery of cost of capital during construction (which may span two or more years in the case of large, technologically complex plant) and the reduction in the accrued cost of capital (in the form of "allowance for funds during construction") added to the rate base, which reduce the need for loans and equity investment during construction, the inclusion of construction work in progress in the rate base may reduce the overall costs borne by ratepayers.

In contrast, under the "used and useful" approach of including in rate base only electricity generating plant investments that both are prudent when made and are actually used and useful, the investor bears more construction and operating risk, as compared to the allocation of risk under the "prudent investment" approach. Under the "used and useful" approach, investors bear the risk of an imprudence finding based on conditions when the decision is made, the risk that subsequent changes may make the completion of the plant no longer prudent, and the risk that the completed plant will not operate properly. Moreover, investors generally cannot begin recovering construction costs until after plant completion. Since plant undergoing construction is, on its face, not yet used and useful, construction work in progress is generally not allowed in the rate base. (There may be an exception for some construction, e.g., construction of emission controls, but the revenue from including such construction work in progress in the rate base may have to be refunded to ratepayers if the plant is not completed.) Ratepayers still bear the risk of cost overruns if the plant was prudently completed but turns out to cost more than projected, if the increased costs are reasonable.

Some utility regulatory commissions have explicitly recognized the resulting increased risk to investors under the "used and useful" approach and have therefore allowed companies a higher return on common equity than in the absence of such risk. This higher return is supposed to compensate investors for the enhanced risk that they will be required to write-off investments, e.g., in electricity generation projects that are cancelled or that never operate properly.

Under a third, less frequently used, approach, the utility regulatory commission considers on an ongoing basis whether to continue allow, in the rate base, plant that was prudent to build and that was initially proved to be used and useful. Under this "economic used and useful" test, plant continues to be allowed in the rate base only if the utility regulatory commission finds that the plant continues to be the most economic alternative for the company. This third approach provides the utility regulatory commission with additional, ongoing opportunities to review investment decisions and shifts additional risk to the investors. Investors, not ratepayers, bear the risk that more economic alternatives become available after the plant is prudently constructed and is at least initially used and useful.

To the extent that a regulated company purchases electricity from another company rather than constructing the new electricity generating plant, the allocation of construction and operating risk is affected by the terms of the power purchase contract and the regulatory approach taken by the utility regulatory commission concerning pass-through of the purchased power costs under the contract. Power purchase contracts (e.g., contracts for purchase of electricity from qualifying facilities under the Public Utility Regulatory Policy Act (PURPA)) generally require payment for capacity and energy only to the extent the plant actually operates to make capacity and electricity available. In that case, the plant investors bear the construction and operating risk, not the purchasing company's investors or ratepayers. However, to the extent that a power purchase contract requires some payment regardless of whether the plant actually operates, the plant investors share the construction and operating risk with the purchasing utility. The allocation of the risk borne in turn by the purchasing utility as between investors and ratepayers depends on the approach taken by the utility regulatory commission. To the extent that the contract costs are allowed as operating costs recovered as part of the cost of service, the risk is allocated to ratepayers. (See discussion below of marketing risk and recovery of operating costs.)

4.22. Marketing risk.

When the new electricity generating plant is owned or operated by a company subject to traditional utility regulation, the allocation of marketing risk depends on several aspects of the ratemaking process and not on market forces because the regulated company is a monopoly with captive customers. In particular, once the utility regulatory commission has determined the extent to which the cost of plant is included in the company's rate base, the allocation of marketing risk depends generally on: how the utility regulatory commission uses test period costs to set rates; how the commission sets rate of return; whether the commission is expeditious in its rate determinations; and whether the commission allows pass-through of costs (e.g., fuel or purchased power costs) through adjustment clauses.

First, utility regulatory commissions generally require that rates be based on actual test period costs, with some adjustments. Utility regulatory commissions have the authority to disallow test period costs determined to be insufficiently related to electric service or imprudent, and this increases investors' risk that revenues will not cover all costs, with the result that earned return on equity may be eroded. In addition, utility regulatory commissions may make adjustments of actual test period costs to make costs representative of normal operation for the period or to reflect anticipated future changes in operation. The adjustment of test period costs, particularly for future changes in costs, tends to reduce investors' risk that revenues will not reflect cost increases and so will erode return on equity. Some utility regulatory commission take an alternative approach to addressing future changes by allowing use of a forward-looking test period based on projected costs and sales.

Second, utility regulatory commissions must determine, for purposes of setting rates, what capital structure, and what cost determination methodologies, to use in determining the company's cost of capital. Utility regulatory commissions generally use the company's actual capital structure in the test period, calculate the actual embedded cost of debt and preferred stock, and use various methodologies to determine the return on common equity. However, some utility regulatory commissions assume -- and determine cost of capital based on -- a hypothetical "optimal" capital structure for the company, rather the company's actual capital structure. That approach increases the marketing risk to investors in that the utility regulatory commission may review not only the investment decision itself but also the means by which the company finances the investment. A determination that the company did not use the optimal capital structure may effectively result in disallowance of a portion of the company's cost of capital. In addition, utility regulatory commissions generally set the cost of capital after the investment has been made and put in rate base and also retain the right to periodically review and change the cost of capital (and, in particular, the return on common equity). This increases the risk to investors that anticipated return may not be realized throughout the life of the investment.

Third, the longer the lag between the time when a rate case is initiated (e.g., when a company requests a rate increase based on test-period cost data) and the time when the utility regulatory commission renders a rate determination and allows new rates to go into effect, the greater the risk borne by investors that revenues will not reflect cost changes and so return on equity will be eroded. As noted above, regulatory lag and resulting risk to investors are reduced to the extent the utility regulatory commission is authorized to allow rates requested by the company to go into effect, subject to refund, before the final rate determination. Obviously, depending on whether costs are generally rising or falling, the delay may actually turn out be advantageous or disadvantageous to investors during a particular period. However, a ratemaking system that tends to result in a relatively close matching of revenues and costs (including return on equity) provides a relatively stable return on equity and tends to reduce investors' risk.

Fourth, in order to mitigate the effect of regulatory lag, many utility regulatory commissions allow the significant, and potentially volatile, costs of fuel to be passed through to ratepayers through adjustment clauses. A fuel adjustment clause establishes a formula under which the fuel-charge portion of the rate is recalculated periodically (e.g., for each upcoming quarter) to reflect recent levels of fuel costs (e.g., fuel costs during the prior quarter) and projected electricity sales. The formula also has a component that takes account of any difference between the dollar amount of fuel costs recovered through the adjustment clause during the prior period (e.g., prior quarter) and that period's actual dollar amount of fuel costs. In that way, over time, the company recovers no more, and no less, than its actual fuel costs. This is important because fuel costs may comprise as much as 40 percent of a utility company's total cost of service. Coordinated to occur with each periodic adjustment, or after several such adjustments, are expedited review proceedings conducted by the utility regulatory commission to ensure that only reasonable, properly calculated costs are passed through. By reducing the risk to investors that volatility of fuel costs will erode the return on common equity, use of adjustment clauses shifts the risk of fuel-cost volatility to ratepayers. Similarly, to the extent purchased power costs (or costs of fuel used to generate purchased power) are passed through an adjustment clause, the risk of volatility of such costs is shifted to ratepayers.

To the extent that a company purchases electricity from another company rather than constructing electricity generating plant, the allocation of marketing risk is affected by the terms of the power purchase contract and the approach taken by the utility regulatory commission concerning recovery of costs under the contract. The power purchase contract may set the power purchase price using a formula that recalculates the price periodically to reflect certain changes in costs (e.g., annual changes in fuel costs). To the extent that the power purchase price is adjustable, marketing risk is imposed on the purchasing company, while to the extent the power purchase price is fixed, marketing risk is imposed on the plant owner. Finally, as between investors and ratepayers of the purchasing company, the allocation of marketing risk is determined by the factors discussed above with regard to other operating costs. In particular, allowed pass-through of purchased power costs through an adjustment clause allocates the risk to ratepayers.

5.0. CURRENT ELECTRIC INDUSTRY STRUCTURE AND REGULATORY SYSTEM IN SPECIFIC STATES.

The degree to which the traditional approach (which is summarized in Section 4.0 above) for the electric industry and its regulatory system applies varies from state to state. Many states have retained a more traditional approach of vertically integrated, monopoly companies providing electricity generation, transmission, and distribution and utility regulatory commissions setting rates using cost-of-service ratemaking. This approach exists along side the approach taken by the FERC to promote competition in wholesale electricity sales and transmission. However, some states have started, or are well along in the process of, separating (functionally within a company or structurally among separate companies) electricity generation from electricity transmission and distribution, promoting competition in retail electricity generation, and allowing the competitive market to determine retail sale prices for electricity. Whether or not the separation is by function or structure, electricity distribution continues to be provided, and regulated, as a monopoly service.

Below is discussed the electric industry structures and regulatory systems in several sample states.[123] Four states with significant coal reserves and production (Indiana, Kentucky, Ohio, and Texas) were selected as sample states because states with significant coal reserves and production are more likely to be interested in encouraging local construction of new IGCC plants in order to promote economic development.[124] In addition, these four states provide a spectrum of industry structure and regulation, ranging from states following a more traditional approach to states following a competitive approach.[125]

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[123] While this draft report focuses on four sample states and briefly discusses regulatory provisions in a few other states, the regulatory systems of additional states warrant further research and consideration for the final report.

[124] The states with significant coal reserves and production (defined, for purposes of this draft report, as states with estimated recoverable reserves of at least 2,500 million short tons and annual production of at least 15,000 thousand short tons) are, grouped by region: West Virginia, Pennsylvania, and Kentucky; Illinois, Indiana, and Ohio; Texas and Alabama; and Montana, North Dakota, Wyoming, Utah, Colorado, and New Mexico. See http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html and http://www.eia.doe.gov/cneaf/coal/page/acr/table15.html.

[125] Of the states with significant coal production, all except the following have retained a more traditional approach to utility regulation: Pennsylvania, Illinois, Ohio, and Texas. See http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

5.1. States with a more traditional electric industry structure and regulatory system.

5.11. Indiana.

Indiana has largely retained a more traditional approach to utility regulation. Indiana statute grants the Indiana Utility Regulatory Commission (IURC) jurisdiction over "public utilities," which term is defined to include as every corporation, partnership, or company that owns, manages, or controls any plant or equipment within the State for "production, transmission, delivery, or furnishing of heat, light, water, or power." IC 8-1-2-1(a). For some (but not all) purposes, the definition of "public utility" excludes municipally owned utilities, and the IURC's jurisdiction over municipally owned utilities is not as broad as its jurisdiction over other public utilities. Compare IC 8-1-2-1(a) (defining "public utility" to exclude municipal utilities) and IC 8-1-8.5-1(a) (defining "public utility" to include municipal utilities). Further, the IURC may decline to exercise jurisdiction over an "energy utility" or over "retail energy service" of an "energy utility." IC 8-1-2.5-5. The IURC has used this authority to decline jurisdiction over merchant plants, but not for electric utilities. See, e.g., Hammond Energy, L.L.C., 2002 WL 32091044 (IURC Nov. 26, 2002) (declining jurisdiction over qualifying facility/merchant plant); see also Citizen's Action Coalition of Indiana v. Indiana Statewide Association of Rural Electric Cooperatives, 693 N.E.2d 1324 (Ind. App.1998) (discussing authority under IC 8-1-2.5-5)

Each "electricity supplier" (i.e., each company that "furnishes retail electric service to the public" (IC 8-1-2.3-2(b)) has either a franchise area within a municipality or an "assigned service area." IC 8-1-2.3-3. The electricity supplier has the sole right to furnish retail electric service in its assigned service area. IC 8-1-2.3-4(a). Further, no license, permit, or franchise to own, operate, or manage or control plant of a utility may be granted in a municipality where a utility already has a license, permit or franchise unless there is a finding that public convenience and necessity require that there be a second utility in such municipality. IC 8-1-86(a). See Indiana Gas Co. v. Office of Utility Consumer Counselor, 575 N.E.2d 1044, 1046 (Ind. App. 3d Dist. 1991) (stating that utility regulation "arises out of a 'bargain' struck between the utilities and the state" under which utilities are regulated to ensure provision of the best possible service as "a quid pro quo for being granted a monopoly in a geographic area" for the service).

Moreover, under Indiana statute, a public utility's rates must be "just and reasonable" (IC 8-1-2-4), and "unnecessary or excessive" costs cannot be considered in setting such rates (IC 8-1-2-48(a)). The rates must be reflected in rate schedules filed with the IURC (IC 8-1-2-38), and no changes may be made to the rate schedules unless the public utility provides 30 days notice to the IURC and the IURC approves the changes (IC 8-1-2-42(a)). A public utility cannot file a request for a general rate increase within 15 months of its prior general rate increase request. Id. However, the IURC may order a "more timely increase" if the increase is for a different type of service, the "utility's financial integrity or service reliability is threatened," or the increase is based on a "rate structure previously approved" or on orders of the federal courts or regulatory agencies. Id.

In addition, the IURC must determine the "fair value" of a public utility's property that is "actually used and useful for the convenience of the public." IC 8-1-2-6. In making this determination, the IURC must consider both the original cost and the reproduction cost of the property (e.g., an electricity generating plant) and must balance this evidence along with other relevant factors to reach a figure that is "fair and equitable to both investor and consumer." Capital Improvement Board of Managers of Marion County .v Public Service Commission, 375 N.E.2d 616, 631 (Ind. App. 2d Dist.1978); see also Indianapolis Water Co. v. Public Service Commission, 484 N.E.2d 635 (Ind. App. 3d Dist. 1985) (holding that IURC cannot ignore "inflation" in determining "fair value" of rate base).

The IURC has some flexibility in setting rates in that it may approve rates based on "market or averages prices, price caps, index based prices, or performance based prices." IAC 8-1-25-6. However, the IURC has generally followed a more traditional approach of cost-of-service ratemaking.

In particular, the IURC uses the following approach to set rates. The IURC's primary objective in a rate case is to establish rates that are "sufficient to permit the utility to meet its operating expenses plus a return on investment which will compensate its investors [citing FPC v. Hope, 320 U.S. 605]". L.S. Ayers & Co. v. Indianapolis Power & Light Co., 351 N.E.2d 814, 819 (Ind. Ct. App. 2d Dist. 1976). This generally involves an initial determination of the utility's future revenue requirement based on the operating results of a test year, which is usually the most recent year for which complete data are available.

The IURC may adjust the test year results in order to disallow excessive or imprudent expenditures or to correct for any unrepresentative operating results. Id. at 819-20; see also City of Evansville v. Southern Indiana Gas and Electric Co., 339 N.E.2d 562, 569-70 (Ind. App. 2d Dist. 1975) (stating that commission has discretion to disallow costs and adjust test period costs to make them representative of normal operation in the test period and of future operation); Indiana Gas, 675 N.E.2d at 745 (stating that rates can not be based on "hypothetical" expenses); and Office of Public Counsellor v. Indiana & Michigan Electric Co., 416 N.E.2d 161, 170-72 (Ind. App. 3d Dist.1981) (upholding commission decision to allow normalization of tax benefits). The IURC may also disallow expenditures that are not sufficiently related to the provision of utility service. Indiana Gas, 675 N.E. at 744 (holding that operating costs must have a "connection" to utility service and upholding disallowance of costs of cleanup of hazardous wastes produced before utility ownership of sites because connection of costs to utility service was "too tenuous").

Further, the IURC must determine the company's rate base, which (as discussed above) must comprise utility property that is "used and useful" in providing the particular utility service involved and that may be valued based on original cost or fair value. See Indianapolis Water, 484 N.E.2d at 638-40. The IURC must also establish a rate of return on the rate base that meets the requirements in Bluefield Waterworks and Improvement, 262 U.S. 679. L.S. Ayers, 351 N.E.2d at 825. The company's cost of capital is determined by considering the amount and cost of each component (debt, preferred stock, and common stock) of the company's capital structure. City of Evansville, 339 N.E.2d at 569-70. In setting rate of return the IURC may consider various factors including "the ability to attract new capital, a comparison with return in other industries, production efficiency, and credit ratings." Office of Utility Consumer Counselor v. Public Service Company of Indiana, 449 N.E.2d 604, 607 (Ind. App. 4th Dist. 1983). However, the IURC must set a rate of return based on the "impact of known circumstances," not on "speculation" on the impact of possible legislation not yet enacted (here, the Acid Rain Program in Title IV of the Clean Air Act, which had not yet been passed). Citizens Action Coalition v. Public Service Co. of Indiana, 612 N.E.2d 199, 201 (Ind. App. 3d Dist. 1993).

Finally, rates may include a fuel adjustment clause. Id. at 591-95; see also IC 8-1-42(b) (stating that no changes in rates "based on costs" are "effective without the approval" of the IURC) and 8-1-2-42(d) (allowing changes in the fuel charge no more frequently than every three months). The fuel cost charge may be based on the cost of fuel used by the public utility to generate electricity or the cost of fuel included in a utility's purchased power costs. The IURC will approve a requested fuel cost charge if, inter alia: the company made "every reasonable effort to acquire fuel and generate or purchase power or both" in order to provide electricity "at the lowest fuel cost reasonably possible"; increased fuel costs are not offset by other decreased operating costs; and the charge will not result in a return exceeding the company's allowed return. IC 8-1-2-42(d)(1) through (3). The public utility must also provide reasonable estimates of future, average fuel costs. Before approving any rate change based on cost of fuel, the IURC must examine the public utility's books and records and hold "a summary hearing on the sole issue of the fuel charge." IC 8-1-2-42(d). The IURC's consumer counselor must review and report to the IURC on any proposed fuel cost charge within 20 days after the request is filed, and the IURC must hold the summary hearing within 20 days after receipt of such report.

Similarly, rates may include other adjustment clauses determined by the IURC to be appropriate. The provisions of IC 8-1-2-42(a) distinguish between "a general increase in basic rates and charges" (e.g., a rate increase in a general rate case) and "changes in rates related solely to the cost of fuel or to the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by" the IURC. In accordance with these provisions, the IURC has approved the inclusion of purchased power costs in adjustment clauses because the costs are potentially volatile. See PSI Energy Inc. v. Indiana Office of Utility Consumer Counsel, 764 N.E.2d 769, 774 n.3 (Ind. App. 2002) (noting commission approval of purchased power adjustment clause for demand component of purchase power contracts). Such costs have been included when they were less than the utility's highest in-system fuel cost. Treatment of Purchased Power Costs, 196 PUR4th 155, 1999 WL 824451 (IURC Aug. 18, 1999). The IURC has also allowed inclusion of payments by the owner of the combined cycle portion of an IGCC plant for coal gasification services provided by the owner of the coal gasification portion of the plant because of uncertainty as to the level of payments over time. PSI Energy, Inc., 173 PUR4th 393, 1996 WL 767535 (IURC Sept. 27, 1996).

The above-described rate-making approach was applied to nuclear plants in Indiana whose construction was commenced but was cancelled in the 1980s prior to plant completion and operation. In some cases, the uncompleted plant was found not to be "used and useful" and so could not be added to the rate base, but the additional risk that this imposed on investors was reflected in the rate of return allowed on the remaining utility property in the rate base. For example, a public utility began construction of a nuclear plant in 1970 but cancelled the project in 1981 due to litigation, opposition to licensing, and escalating costs. Determining that the decision to build the plant was prudent when construction began, the IURC allowed the utility to amortize, and thereby recover in its rates, about $191 million out of a total of about $206 million invested in the project. No return on the capital was allowed. On review, the Indiana Supreme Court reversed the IURC's decision on the ground that uncompleted plant was not used and useful. Citizens Action Coalition of Indiana Inc. v. Northern Indiana Public Service Co., 485 N.E.2d 610, 612 (Ind. Sup. Ct. 1985), cert. den., 476 U.S. 1137 (1986). As the Court explained, the ratepayers cannot be required to "replenish lost capital which had never become 'used and useful' property or, in other words be required to act...., as insurer of the investor's risk, unless the consumers received an interest in return which provided an opportunity to earn a return on the capital supplied." Id. at 615. The Court distinguished between plant that was used and useful and so could be amortized after retirement and plant that never became used and useful and so could not be amortized. See also National Rural Utilities Cooperative Finance Corp. V. Public Service Commission of Indiana, 528 N.E.2d 95, 103 (Ind. App. 3d Dist., 1988), aff'd, 552 N.E.2d 23 (Ind. Sup. Ct. 1990) (upholding denial of recovery of costs of cancelled nuclear plant as not "used and useful" even though company was insolvent).

In light of the Court's 1985 Citizens Action Coalition of Indiana decision, the IURC took an different approach concerning recovery of costs incurred by another public utility for another cancelled nuclear plant. That public utility began construction of a nuclear plant but cancelled the project in light of construction delays, cost escalations, and a task force report recommending cancellation. Consistent with Citizens Action Coalition of Indiana, the IURC did not allow recover of the costs of the cancelled plant. However, in setting the company's rates, the IURC added a risk premium to the rate of return on the company's rate base (which did not include the nuclear plant costs). Upon review of the IURC's decision, the Court upheld the approval of a risk premium as reflecting the company's increased risks of lack of access to capital markets, cash flow deficiency, inflated equity cost, and insolvency as a result of the writing off of the company's investment in the cancelled nuclear plant. Citizens Action Coalition of Indiana Inc. v. Public Service Co. of Indiana, 552 N.E.2d 834, 838 (Ind. App. 3d Dist., 1990).

The IURC took further action concerning recovery of the company's cancelled plant investment. The IURC allowed the utility to recover, as an amortized "regulatory asset," $475 million of federal income tax savings that would be realized from deducting the utility's net loss due to the plant cancellation from the utility's net income. The Court had previously held that such tax savings should be retained by the utility. Id. at 839-40. Although the federal income tax rate was subsequently reduced, the IURC did not reduce the utility's rates to reflect the lower tax benefit. The Court reversed the IURC on the ground that the failure to reduce rates to reflect the reduced tax benefit had effect analogous to amortizing cancelled plant, which approach had been previously rejected. Citizens Action Coalition of Indiana v. Public Service Co. of Indiana, 582 N.E.2d 330, 336 (Ind. Sup. Ct. 1990).

After the decisions denying recovery of costs of cancelled nuclear plants, Indiana adopted statutory provisions to allow for recovery of cancelled plant under certain circumstances. See National Rural Utilities Cooperative Finance, 552 N.E.2d at 28 (explaining that the nuclear plant at issue was terminated before these new provisions were effective). Under these provisions, proposed construction of new facilities by a public utility (including a municipal utility) must be approved up front by the IURC. In particular, the IURC must develop and keep current an analysis of the long-range needs for expansion of facilities for electricity generation in the state. IC 8-1-8.5-3(a). A public utility must not construct, purchase, or lease any electricity generating facility (e.g., a new IGCC plant) without first obtaining a certificate of public convenience and necessity from the IURC. IC 8-1-8.5-2. The company must file an estimate of the construction, purchase, or lease cost of the facility. IC 8-1-8.5-5(a). In approving a certificate for the proposed facility, the IURC must make a finding on the best estimate of the facility's costs and findings that, inter alia, the facility is required by the public convenience and necessity and is consistent with the IURC's analysis of long-range needs and with any approved utility-specific proposal as to future needs for serving the state or the company's service area. IC 8-1-8.5-5(b). See IC 8-1-8.5-3(e) (requiring company to provide a utility-specific proposal for any new facility).

Moreover, the certificate of public convenience and necessity is subject to future review by the IURC. The certificate must be reviewed if the IURC's estimate of future growth in electricity use changes and must be modified or revoked if completion of the facility is no longer in the public interest. IC 8-1-8.5-5.5. In addition, as construction of the facility proceeds, the IURC must conduct, at the company's request, an ongoing review of construction and costs and may modify or revoke the certificate if construction or costs are disapproved. However, company has the option of electing to have the IURC instead conduct review of construction and costs only subsequent to completion or cancellation of the facility. IC 8-1-8.5-6. In general, absent fraud, concealment, or gross mismanagement, a company must be allowed to recover through its rates the actual costs that the company incurs in reliance on the certificate of public convenience and necessity for the facility. IC 8-1-8.5-6.5. Cost recovery begins once the facility is completed and used and useful or, to the extent allowed, after the facility is cancelled and construction is terminated.

The advantage of ongoing review by the IURC is that construction costs approved in the ongoing review (and a return on those costs) must be included in the company's rates without further IURC review. This includes cases where the facility is cancelled due to modification or revocation of the certificate as a result of a change in the IURC's future growth estimates of construction or cost disapproval in the ongoing review. IC 8-1-8.5-6.5(1) and (3). Further, risk is shifted earlier (i.e., after each ongoing review proceeding) in the plant development process from investors to ratepayers. In contrast, if only subsequent review is conducted by the IURC, then construction costs of completed or cancelled plant within the certificate amount are included in rate base unless they result from "inadequate quality control" and such costs in excess of the certificate amount are included in rates only if the construction is shown to be "necessary and prudent." IC 8-1-8.5-6.5(4). Also risk does not shift from investors to ratepayers until the after-the-fact-review is conducted. While companies have requested, and the IURC has approved, certificates for new electricity generation plant, none of these plants have been cancelled and so the provisions concerning recovery of costs of cancelled plant have not as yet been applied.

Indiana adopted similar statutory provisions concerning approval of, and cost recovery for, capital projects associated with compliance with requirements (primarily the Acid Rain Program) under the Clean Air Act Amendments of 1990. A company has the option of submitting an environmental compliance plan (IC 8-1-27-6), which includes the costs of developing and implementing the plan and is reviewed by the IURC (IC 8-1-27-12). In the absence of "fraud, concealment, gross mismanagement, or inadequate quality control," the company may include in rate base the costs of completed projects consistent with the approved plan. IC 8-1-27-12. To the extent such costs exceed the amount in the approved plan, the costs may be recovered if they are "necessary and prudent." Id. If the plan is modified by the IURC, costs consistent with the approved plan and incurred before modification of the approved plan may be included in rate base. IC 8-1-27-16 and 8-1-27-17. The IURC may conduct an ongoing review of the capital project during construction, and recovery of costs approved in such review cannot be challenged if the project is "used and useful." IC 8-1-27-19.

Finally, Indiana has adopted over several years an array of special provisions aimed at encouraging "clean coal technology." The earliest provision, IC 8-1-2-6.6 (initially adopted in 1985), addresses inclusion in rates of certain construction costs associated with "clean coal technology," which is defined as technology that "directly or indirectly" reduces sulfur or nitrogen based emissions associated with combustion or use of coal and that is "not in general commercial use at the same or greater scale" in the U.S. as of January 1, 1989. A company may include in rate base, as construction work in progress or CWIP, the value of air pollution control property whose construction began after October 1985 and is ongoing and that constitutes clean coal technology approved by the IURC and designed to "accommodate" burning of Illinois Basin coal. The facility must burn "only Indiana coal as its primary fuel source" (IC 8-1-2-6.6(a)) or show justification for burning "some non-Indiana coal" (IC 8-1-2-6.6(b)).

This provision (along with IC 8-1-27, discussed above) was successfully challenged as contrary to the commerce clause of the U.S. Constitution because of its limitation to controls on facilities designed for and burning Indiana coal. GM Corp v. Indianapolis Power & Light, 654 N.E.2d 752, 766-67 (Ind. App. 1995). A similar provision was adopted (in 1990) that allows rate base treatment of air pollution control property (as construction work in progress) where the property's construction began after March 2002 and is ongoing, but the provision is not limited to facilities designed for and burning Indiana coal. The provision defines, as clean coal technology, technology that reduces mercury (as well as technology that reduces sulfur or nitrogen emissions) and that was not in general commercial use on November 15, 1990. IC 8-1-2-6.8.

Under either IC 8-1-2-6.6 or 8-1-2-6.8, the company may request rate base treatment to the extent that the qualified air pollution control property has been under construction for at least 6 months. 170 IAC 4-6-9. The inclusion of a portion of the value of air pollution control property under construction in rate base, for purposes of a general rate case, means that the company's rates may recover the cost of capital (i.e., return on debt and equity) associated with that portion of company's investment in such property. The IURC must approve the use of air pollution control property if, inter alia, the costs are reasonable and must allow rate base treatment, during construction, of approved air pollution control property. 170 IAC 4-6-4 and 4-6-10. The IURC may grant rate base treatment in a general rate proceeding, in a certification proceeding under IC 8-1-8.5, in an analogous proceeding (discussed below) under IC 8-1-8.7, or in a proceeding for review of the company's environmental compliance plan under the Clean Air Act under IC 8-1-27. 170 IAC 4-6-11. See IC 8-1-27-12 and IC 8-1-27-19 (allowing company to add to rate base equipment under approved environmental compliance plan). Rate base treatment of air pollution control property when construction is cancelled is governed by the appropriate provisions under IC 8-1-8.5, 8-1-8.7, or 8-1-27. After its initial request for rate base treatment of air pollution control property, the company may request such treatment for additional amounts of such property in six-month intervals. 170 IAC 4-6-18. Assuming that the IURC's handling of such requests takes about three months, this means that a company may recover, on an ongoing basis, the cost of capital for each six-month portion of investment in air pollution control equipment about nine months after making that portion of the investment. During the lag period between making the investment and including the cost of capital of the investment in the rates, the company treats the cost of capital as allowance for funds during construction (AFUDC). The

AFUDC is subsequently treated as part of the value of the investment and is eventually added to rate base, consistent with the appropriate provisions under IC 8-1-8.5, 8-1-8.7, or 8-1-27.

The IURC has applied IC 8-1-6.6 and 8-1-6.8 to projects involving construction of nitrogen oxides emission controls (e.g., selective catalytic reduction control equipment and combustion modifications such as low NOx burners) undertaken by some utilities. See, e.g., PSI Energy, Inc., 2001 WL 401306 at 6 (IURC Feb. 14, 2001). Although the operative terms in these provisions, "air pollution control property" and "clean coal technology," have been applied to emission controls, the terms seem broad enough to include an entire IGCC plant, which integrates coal gasification, synthesis gas cleaning, combined cycle, and emission control technologies to achieve clean use -- with, e.g., reduced sulfur dioxide, nitrogen oxide, and mercury emissions -- of coal to generate electricity. Moreover, in several cases, the IURC held that it has the authority to allow a utility to recover -- through an adjustment clause, rather than in a rate case -- the cost of capital for investment in such projects during ongoing emission control installation. The IURC stated that it was adopting this approach because: the investment in the projects was substantial; it would be difficult to coordinate initiation of rate cases with investments in ongoing construction; and the inability to recover costs of capital on an ongoing basis would have a significant, adverse impact on the companies involved. See, e.g., Northern Indiana Public Service Co., 2002 WL 32089927 at 9 (IURC Nov. 26, 2002); and Indianapolis Power & Light Co., 2002 WL 32091040 at 8 (IURC Nov. 14, 2002).

Indiana statute includes two other provisions (IC 8-1-2-6.1 and 8-1-2-6.7) affecting the timing recovery of investment in clean coal technology. The IURC is required to allow recovery, "as operating expenses," of "preconstruction costs (including design and engineering costs) associated with employing clean coal technology" that is certificated if the project uses and will continue to use Indiana coal as the primary fuel or is justified in using non-Indiana coal. IC 8-1-2-6.1. A company may seek treatment of such costs as operating costs in a general rate case. 170 IAC 4-6-16. The provision allows these preconstruction costs to be recovered on a more timely basis than would treating them as capital expenditures to be amortized.

Under IC 8-1-2-6.7 (adopted in 1989), clean coal technology is allowed a depreciation period, for rate making purposes, of not less than the lesser of 10 years or the property's useful economic life and not more than 20 years if the facility uses Indiana coal or shows justification for using non-Indiana coal. The provision in effect allows accelerated depreciation of such property. For example, clean coal technology with a useful life between 10 and 20 years may be depreciated over a period that may be as short as 10 years while such technology with a useful life exceeding 20 years may be depreciated over a period ranging from 10 to 20 years.

Indiana statute also includes other special provisions -- similar to the electricity-generating-plant certification provisions under IC 8-1-2-6.5 -- concerning approval of, and recovery of costs (including depreciation or amortization of capital expenditures, as well as cost of capital) associated with, clean coal technology. Under IC 8-1-8.7-3(a), a public utility (including a municipal utility) must apply for and obtain a certificate of public convenience and necessity before using clean coal technology at an electricity generating facility. The IURC must issue a certificate if the project offers "substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989." IC 8-1-8.7-3(b). In issuing a certificate, the IURC must make findings on the estimated project costs and on the expected "dispatching priority" for the project (IC 8-1-8.7-3(b)(8)), as well as findings that the public convenience and necessity will be served and that the project will use Indiana coal as the primary fuel or is justified in using non-Indiana coal. IC 8-1-8.7-4(b). The IURC may modify or revoke the certificate in light of changes in the estimate of cost of or need for clean coal technology. IC 8-1-8.7-5. If the project is cancelled due to modification or revocation of the certificate, the company may recover its "investment in the technology, along with a reasonable return on the unamortized balance." IC 8-1-8.7-6. However, costs in excess of the approved costs in the certificate may be recovered only if there is a showing that the excess costs were "necessary and prudent" and there was no "fraud, concealment, or gross mismanagement" by the company. Id.

After certification of the clean coal technology, the IURC will conduct, at the request of the company, an ongoing review of the construction and costs of the project as construction progresses. IC 8-1-8.7-7(b). The IURC has issued such certificates with ongoing review for nitrogen oxides control equipment, allowed recovery of the cost of capital on such construction work in progress under IC 8-1-2-6.6, and coordinated the ongoing review proceedings with the six-month updates for recovery of such cost of capital. See e.g., Southern Indiana Gas and Electric Co., 2001 WL 1708778 at 14-15 (IURC Aug. 29, 2001) and PSI Energy, Inc., 2003 WL 21004706 (IURC Jan. 29, 2003). Upon approval of construction and costs in such a review, the inclusion in the rate base of that part of the clean coal technology cannot be challenged "on the basis of excessive cost, inadequate quality control, or inability to employ the technology." IC 8-1-8.7-7(c). If construction and costs are disapproved in the ongoing review process, the IURC may modify or revoke the certificate. If, as a result, the project is cancelled, the public utility can recover its previously approved investment plus a reasonable return, absent fraud, concealment, or gross mismanagement. IC 8-1-8.7-7(d).

The public utility has the option of having the IURC review construction and costs only after completion of the project. However, costs exceeding the costs in the certificate may be included in rate base only if shown to be "necessary and prudent," while costs within the certificate amount can be challenged only "on the basis of inadequate quality controls." IC 8-1-8.7-8. Upon completion of the project, the public utility may dispatch it in accordance with the dispatch priority set forth in the certificate, and such dispatching "shall not be considered to be in conflict with" the requirements for recovery of costs through a fuel adjustment clause (under IC 8-1-2-42). IC 8-1-8.7-9. Presumably this means that such dispatching may not be used as a basis for challenging recovery of fuel costs on the ground that the public utility failed to make "every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." IC 8-1-2-42(d)(1).

As noted above, the provisions for certification and cost recovery for clean cost technology (IC 8-1-8.7-3 through 8-1-8.7-9) are similar to the general certification and cost recovery provisions (IC 8-1-8.5-2 through 8-1-8.5-6.5) applicable to all new electricity generating facilities. For electricity generating facilities that will use clean coal technology, both sets of provisions apply. IC 8-1-8.7-10. For example, the Wabash gasification facility was certificated under both IC 8-1-8.5 and 8-1-8.7. PSI Energy, Inc., 143 PUR4th 521, 1993 WL 328722 (IURC May 26, 1993). Apparently, no facilities (including the Wabash gasification facility) certificated under IC 8-1-8.5 and IC 8-1-8.7 have as yet been terminated and so the provisions concerning recovery of costs for cancelled plant have not yet been applied.

Finally, under two relatively new Indiana statutory provisions, IC 8-1-8.8-11 and 8-1-8.8-12, the IURC has additional authority. Specifically, the IURC must encourage "clean coal and energy projects" by providing certain financial incentives if the projects are "reasonable and necessary."[126] IC 8-1-8.8-11(a). "Clean coal and energy projects" include: new energy generating facilities using clean coal technology, or advanced emission reduction technology for existing energy generating facilities, that are fueled primarily by coal or gas derived from coal from the Illinois Basin; projects for transmission to serve new energy generating facilities; projects using alternative energy sources such as renewables; and "the purchase of fuels produced by a coal gasification facility" in Indiana. IC 8-1-8.8-2. "Clean coal technology" under this provision is technology that "directly or indirectly" reduces emissions "associated with the combustion or use of coal" and not in general commercial use at the same or greater scale in the U.S. as of November 15, 1990. IC 8-1-8.8-3. "New energy generating facilities" include new construction, repowering, or capacity expansion after July 1, 2002 that is "dedicated primarily to serving Indiana retail customers." IC 8-1-8.8-8. The types of financial incentives that the IURC must provide include: timely recovery of construction and operating costs; authorization of up to three additional percentage points on return on equity; incentives (e.g., timely cost recovery and additional return on equity) for purchase of fuels produced by a coal gasification facility in Indiana; and incentives for development of alternative energy sources. IC 8-1-8.8-11(a). If a company applies for financial incentives under this provision, the IURC must make a determination of eligibility for such incentives within 120 days, unless the company does not cooperate fully in the proceeding. IC 8-1-8.8-11(d).

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[126] West Virginia, another coal state that uses more traditional utility regulation, has a similar provision requiring the West Virginia Public Service Commission to "authorize rate-making allowances for electric utility investment in clean coal technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia" in order to encourage such investment. WVC 24-2-1g(b).

The IURC is also required to provide financial incentives for "new energy generating facilities" in the form of "timely recovery" (e.g., through a retail rate adjustment mechanism) of "costs incurred in connection with the construction, repowering, expansion, operation, or maintenance of the facilities." IC 8-1-8.8-12(a). Specifically, the IURC must allow recovery of costs associated with qualified utility system property if "the expected costs...and the schedule for incurring those costs are reasonable and necessary." IC 8-1-8.8-12(d). Similarly, the IURC must allow recovery of costs associated with purchase of fuel produced by a coal gasification facility if the costs are "reasonable and necessary." IC 8-1-8.8-12(e). Arguably, the term "timely recovery" in IC 8-1-8.8-12, as well as in IC 8-1-8.8-11, refers to, inter alia, inclusion of construction work in progress in the rate base in order to allow for ongoing recovery of cost of capital for such construction and recovery of these and other costs through an adjustment clause (rather than through a rate case).

The IURC has coordinated its application of IC 8-1-8.7-3 through 8-1-8.7-9 and IC 8-1-8.8-11 and 8-1-8.8-12 in cases involving nitrogen oxides emission controls undertaken by some utilities. As noted above, the IURC issued certificates of public convenience and necessity for the emission control projects and agreed to conduct ongoing review during construction. Further, the IURC approved not only adjustment-clause recovery of the cost of capital during construction of such projects, but also adjustment-clause recovery of depreciation and operation and maintenance costs for the projects once the emission control projects go into service. See, e.g., Southern Indiana Gas and Electric Co., 2003 WL 21048981 (IRUC Jan 2, 2003); Northern Indiana Public Service Co., 2002 WL 32089927 (IURC Nov. 26, 2002); and Indianapolis Power & Light Co., 2002 WL 32091040 (IURC Nov. 14, 2002). This approach ensures a dedicated stream of revenues covering all costs -- starting with cost of capital on construction work in progress and continuing with return of and on capital and operating costs -- of the emission control projects.

It seems that Indiana stature authorizes the IURC to adopt the same approach for a new IGCC plant. Such a plant seems to qualify as a new electricity generating facility and as clean coal technology eligible for certification and ongoing review under IC 8-1-8.5-2 through 8-1-8.5-6.5 and IC 8-1-8.7-3 through 8-1-8.7-9. In addition, such a plant seems to qualify for inclusion of construction work in progress in rate base, and for adjustment-clause recovery of cost of capital during construction and of capital investment, cost of capital and operating costs after commencement of plant service, under IC 8-1-6.8, 8-1-8.8-11, and 8-1-8.8-12. This approach will provide an assured revenue stream for full cost recovery for the IGCC plant.

5.12. Kentucky.

Kentucky has largely retained a more traditional approach to utility regulation. Kentucky statute provides the Kentucky Public Service Commission (KPSC) with authority to regulate any "utility", i.e., any person (except a municipality) that owns, controls or operates or manages a facility used or to be used for "generation, production, transmission or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses." KC 278.010(3).

Because the legislature determined that it was in the public interest to divide the state into geographical areas with one retail electric supplier for each certified territory (KC 278.016), the KPSC is required to set boundaries of the certified territory for each retail electric supplier based on the service areas as of 1972 (KC 278.017). Each retail electric supplier has an "exclusive right to furnish retail electric service to all electric consuming facilities" in its certified territory and must not provide service to customers in the certified territory of another retail electric supplier. However, if a supplier fails to provide adequate service to an electric consuming facility, the KPSC may authorize another supplier to provide the service. KC 278.018.

Further, no person may begin providing utility service "to or for the public" or begin construction of any plant for furnishing utility service without a certificate of public convenience and necessity. KC 278.020(1). There is an exception from this requirement for a retail electric supplier for "service connections to electric-consuming facilities" in its certified territory and for "ordinary extension of an existing system in the usual course of business." Id. A determination of public convenience and necessity requires findings of a need for a new facility to meet service requirements and an absence of wasteful duplication and multiplicity of physical properties. In considering an application for a certificate "to construct a base load electric generating facility," the KPSC may "consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities" serving Kentucky. Id. See Kentucky Utilities Co. v. Public Service Commission, 252 S.W.2d 885, 890 (Ken. App. 1952); and Kentucky Utilities Co. v. Public Service Commission, 390 S.W.2d 168 (Ky. App. 1965). A certificate must be exercised within one year in order to remain valid.

A utility must charge "fair, just and reasonable rates" for services (KC 278.030(1)), which rates must be set forth in filed rate schedules (KC 278.160). See Stephens v. South Central Bell Telephone Co., 545 S.W.2d 927 (Ky. Sup Ct. 1976) (citing FPC v. Hope, 320 U.S. 591, in explaining that rates must be just and reasonable). When a utility files new rates, the KPSC may suspend the effectiveness of the new rates for up to five months if the rates are based on costs from a historical test period and up to six months if the rates are based on projected costs from a forward-looking test period. The rates then go into effect subject to refund. However, if KPSC determines that, because of the failure to allow the rates to become effective before the end of the suspension period, the "company's credit or operations will be materially impaired or damaged," then the KPSC may let the rates become effective sooner. Id.

Kentucky statute sets forth basic procedures for setting just and reasonable rates. Rates may be based on costs from a historical test period or a forward-looking test period. For proposed general rate increases, the KPSC must allow a utility to use a historical test period of 12 calendar months before the proposed rate filing or a forward-looking test period of 12 calendar months after the maximum suspension period. KC 278.192(1). The historical test period data may be adjusted for "known and measurable changes." 807 KAR 5:001 §10(1)(a). A rate filing using a forward-looking period must provide data on nine months before the filing, including at least six months of actual data. KC 278.192(2). The KPSC generally bases rates on a historical, rather than a forward-looking, test period. But see Kentucky American Water Co., 1993 WL 595984 at 18 (KPSC Nov. 19, 1993) (stating that use of a forwarding-looking test period "tends to decrease the risk that...[a utility] will not earn its allowed return" and taking this into account in setting return on equity).

Further, the KPSC may "ascertain and fix the value of the whole or any part of the property of any utility in so far as the value is material to the exercise of the jurisdiction of the Commission." KC 278.290(1). The KPSC may make "revaluations" of such property. Id. In fixing such value, the KPSC must "give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes." Id. On its face, this provision does not limit determinations of rate base to facilities that are "used and useful."

On the contrary, the provision has been held to be "broad enough" to allow the KPSC to consider additional factors in the case of a cooperative with a share of a new nuclear plant that was producing more electricity than currently needed to meet the cooperative's customer load. National Southwire Aluminum Co. v. Big Rivers Electric Cooperative, 785 S.W.2d 503, 512 (Ky App. 1990). Although in previous cases the KPSC had limited rate base to facilities that were "used and useful (see, e.g., Fern Lake Co. v. Public Service Commission, 375 S.W.2d 701 (Ky. App. 1962) and Blue Grass State Telephone Co. v. Public Service Commission, 382 S.W.2d 81 (Ky. App.1964)), the Court upheld consideration by the KPSC of other factors in this case. In particular, the Court held that the KPSC could consider "replacement cost, debt retirement, operating costs, and at least some excess capacity in order to ensure continuation of adequate service during periods of high demand and some potential for growth and expansion." National Southwire Aluminum, 785 S.W.2d at 512. The KPSC could also consider "whether expansion investments were prudent or imprudently made, and whether a particular utility is investor owned or a cooperative operation." Id. Noting that the nuclear plant was not like "an incomplete nuclear plant" and was "not a useless facility", the Court upheld the KPSC's order setting rates high enough for the cooperative to pay its debt on the plant under a workout plan, which plan allowed the cooperative to avoid bankruptcy and provided a longer pay-back period and lower interest rate. Id. at 513. As the Court explained, there is "no litmus test" for setting fair, just, and reasonable rates and "no single prescribed method to accomplish this goal." Id.

Once the rate base valuation is determined, the KPSC must set the rate of return on that rate base. The method for setting rate of return may vary depending on the method used to value the rate base. Citizens Telephone Co. v. Public Service Commission, 247 S.W.2d 510 (Ky. App. 1952) (explaining that, where rate base is valued at reproduction costs, allowed return on capital may be lower than where rate base is valued at original cost).

Finally, rates may include an automatic adjustment clause for fuel and purchased power costs. The adjustment clause may provide for periodic (monthly) adjustment per kilowatthour of sales equal to changes in fuel costs. Fuel costs under the adjustment clause include: the cost of fuel consumed in the utility's plants or the utility's share of fuel costs at jointly owned or leased plants plus the cost of fuel that "would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation" resulting from such forced outages (807 KAR 5:056 §1(3)(a)); and the cost of fuel associated with purchased power other than such substitute generation (807 KAR 5:056 §1(3)(b) and (c)). The KPSC reviews every six months the charges under the adjustment clause to correct for "improper calculation or application of the charges or improper fuel procurement practices." 807 KAR 5:056 §1(11). Every two years the KPSC reviews the past operation of the adjustment clause and may "disallow improper expenses" and reestablish the adjustment clause. 807 KAR 5:056 §1(12).

Moreover, the KPSC has offered to adopt for electric utilities an optional earnings sharing mechanism under which the amount of earnings above or below a specified earnings band would be shared (on a 60 percent to 40 percent basis) between investors and ratepayers through an automatic monthly credit or surcharge (as appropriate) that would trued up annually. Kentucky Utilities, 2000 WL 3099547 at 20-21 (KPSC Jan. 7, 2000). This approach has been adopted for some utilities in the state. See, e.g., Kentucky Utilities Co., 2000 WL 872715 (KPSC Jun. 1, 2000).

Finally, under legislation enacted in 1992, the KPSC is required (starting January 1, 1993) to allow recovery through a rate surcharge, which is analogous to the fuel adjustment clause, for utilities' costs of complying with certain environmental requirements. Specifically, Kentucky statute provides that, "[n]otwithstanding any other provision of" the state utility law, "a utility "shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those Federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal" in accordance with a utility's approved compliance plan.[127] KC 278.183(1). The compliance

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[127] Colorado, another coal state that uses more traditional utility regulation, has a similar provision stating that a public utility is "entitled to fully recover the air quality improvement costs that it prudently incurs" under a voluntary agreement with the Colorado Department of Public Health and Environment to reduce emissions. CRS 40-3.2-102(1). The Colorado Public Utilities Commission must determine "an appropriate method of cost recovery that assures full cost recovery. " CRS 40-3.2-102(3). See, e.g., Public Service Co. of Colorado, 1999 WL 716478 (Jun. 16, 1999) (recommended decision approving recovery of air quality improvement costs (including capital investment, cost of capital, and operating costs) through "Air Quality Improvement Rider," a nonbypassable charge applied to all retail deliveries by utility); and Public Service Co. of Colorado, 2002 WL 32073085 (Dec. 19, 2002)

costs include " a reasonable return on construction and other capital expenditures and reasonable operating expenses," including operation and maintenance, taxes, and depreciation. Id. The costs must not be already reflected in existing rates. KC 278.183(2).

A utility may request such recovery through a rate "surcharge" applied starting in the second month after the month in which the costs to be recovered are incurred. At least 30 days in advance of commencing the surcharge, the utility must file a notice of intent to submit a plan for complying with the applicable environmental requirements and must subsequently file the plan. Id. Within six months of the filing, the KPSC must review the compliance plan and the rate surcharge, including the rate of return on the environmental capital expenditures. In addition, the KPSC must review the rate surcharge every six months and make a "temporary adjustment" to disallow any amounts that are not "just and reasonable" and to "reconcile past surcharges with actual costs." KC 278.183(3). The KPSC must also conduct review every two years and "disallow improper expenses" and incorporate the surcharge amounts into the utility's general rates. Id. In conducting these reviews, the KPSC is not required to carry out a full review of the utility's overall financial condition as is required in a general rate case. Instead, the KPSC can separately consider the relevant environmental costs, in a manner analogous to the review of fuel costs in a review of a fuel adjustment clause. Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Co., 983 S.W.2d 493, 498 (Ky. Sup. Ct. 1998). On appeal, these provisions were upheld, with the Court holding that the Kentucky legislature had a legitimate interest in promoting "the use of Kentucky coal so as to provide jobs and other economic benefits in Kentucky" and to balance investor and ratepayer interests in a way that reflects that interest. Id. at 497; see also Kentucky Utilities Co., 2000 WL 309957 at 25 (KPSC Jan. 7, 2000) (holding that KC 278.183 provides a "stand alone cost recovery mechanism" separate from a general rate case).

The KPSC has approved use of this cost recovery mechanism for recovery of rate of return on construction work in progress and plant in service, depreciation, and operating costs for emission controls through an environmental surcharge. See, e.g., Kentucky Utilities Co., 2003 WL 21246131 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for sulfur dioxide emission controls and rejecting surcharge recovery of landfill site costs because latter costs were then too uncertain for KPSC to determine reasonableness and cost- effectiveness of landfill site); and Kentucky Utilities Co., 2003 WL 21246128 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for fly and bottom ash pond dike).

The 1992 provision for surcharge recovery of the "costs of complying" with environmental requirements does not, of course, specifically reference IGCC plants. However, the language of the provision is sufficiently broad to cover at least the gasification and synthesis gas cleaning portions of an IGCC plant, since the primary purpose of the gasification and synthesis gas

(approving recovery of air quality improvement costs through "Air Quality Improvement Rider").

cleaning processes is to derive from coal a clean gas that is combusted in a manner that significantly reduces both sulfur dioxide and nitrogen oxide emissions. It may be argued that the entire IGCC plant, which uses coal gasification, synthesis gas cleaning, combined cycle, and combustion emission control technologies to achieve clean use of coal to generate electricity, is a means of "complying" with environmental requirements.

The applicability of this provision (KC 278.183) is not stated as broadly as the Indiana provisions (e.g., IC 8-1-8.8-11 and 8-1-8.8-12) applying to "clean coal and energy projects" and "new energy generating facilities." In addition, the Kentucky provision appears to require allowance of more rapid, but perhaps less certain, cost recovery than the Indiana provisions. Specifically, under KC 278.183 the utility may adjust the surcharge each month and pass through costs on an ongoing basis without up-front review by the KPSC, but subject to KPSC review every six months and every two years. It seems that the KPSC can disallow costs and require refund of the pass-through as late as two years after the pass-through occurs. Since Kentucky statute establishes an entitlement to recovery for environmental compliance costs "[n]otwithstanding any other provisions of" state utility law (KC 278.183(1)), it appears (but is not absolutely clear) that the KPSC would not disallow recovery of costs of facilities simply because they were not completed and so were not used and useful. In contrast, the IURC allows the utility to adjust the charge under the adjustment clause every six months and to pass through the costs only after IURC review. It appears that once the IURC approves six-months' worth of capital expenditures, reevaluation of the reasonableness of the expenditures is generally not allowed, in the absence of "fraud, concealment, or gross mismanagement," even if the facility is no completed. See IC8-1-8.7-7(d).

5.2. States with restructured electric industry and competitive retail electricity generation and sales.

5.21. Ohio.

Until January 1, 2001 when the Public Utilities Commission of Ohio (PUCO) began to implement "competitive retail electric service" under the state's utility deregulation statute, Ohio followed a more traditional approach of regulating electric utilities as vertically integrated monopolies. The PUCO is granted "power and jurisdiction to supervise and regulate public utilities." ORC 4905.04. Ohio statute defines "public utility" as including any "electric light company, when engaged in the business of supplying electricity for light, heat, or power purposes to consumers", with an exception for municipal utilities. ORC 4905.03; see also ORC 4905.02. An electric light company (also referred to as an "electric supplier") has a "certified territory" in which the company has the "exclusive right to furnish electric service to all electric load centers." ORC 4933.83(A). In general, an electric light company's "certified territory" is its service area as of 1978. See ORC 4933.83(B). The company may not extend electric service to load centers in another company's certified territory. Id. (Under the regulatory regime in place for retail electricity service until 2001, "electric service" included retail electric generation, which starting in 2001, was exempted from "electric service." See ORC 4933.81(F).) However, municipalities retain the right to generate, transmit, distribute, or sell electricity. ORC 4933.97; see Toledo Edison Co. v. City of Bryan, 737 N.E.2d 529, 533 (Ohio Sup. Ct. 2000) (holding that municipalities may generate or purchase electricity for residents but not for the purpose of selling outside municipal boundaries).

Before anyone can commence construction of a "major utility facility," including any electricity generation plant of 50 MWe or more (ORC 4906.01), a certificate must be issued for the facility by the PUCO's power siting board. ORC 4906.04. There is an exception for the certificate requirement for replacement of an existing facility "with a like facility." Id. In issuing a certificate, the board must make findings on the need for the facility and the nature of the probable environmental impact of the facility and whether the facility will serve the "public interest, convenience, and necessity." ORC 4906.10(A)(6).

The PUCO determines "just and reasonable rates" for public utility service (which until 2001 included retail electricity service). ORC 4905.22 and 4909.15(A). A public utility must file an application to establish or change any rate. ORC 4909.18. When the PUCO fails to issue a final order on a proposed rate increase within 275 days, the rate goes into effect subject to refund, if the company provides an "undertaking" payable to the PUCO in order to ensure refunds will be made as appropriate. If the PUCO does not issue a final order within 545 days, the company has no refund requirement for amounts collected after the latter deadline. ORC 4909.42.

In determining just and reasonable rates for a public utility, the PUCO must determine: a "fair and reasonable rate of return" on the value of public utility property (ORC 4909.15(A)(2)); and the "cost to the utility of rendering the public utility service" for a test period (ORC 4909.15(A)(4). Determination of a "fair and reasonable rate of return" is "prospective" and must be based on current, not historical, data. Babbit v. Public Utility Commission, 391 N.E.2d 1376, 1383 (Ohio Sup. Ct. 1979). The test period for determining a public utility's costs of service is generally a 12-month period starting six months before the application for rates or a rate change is filed and not ending more than nine months after such filing. The PUCO can order use of a different test period. ORC 4909.15(C). Generally, test year revenues and expenses may not be adjusted in order to set rates. Dayton Power & Light Co. v. Public Utility Commission, 447 N.E.2d 733, 736-37 (Ohio Sup. Ct. 1983). The exception is where adjustment is necessary to prevent "an anomaly in the ratemaking equation making the test year unrepresentative for ratemaking purposes." Board of Commissioners of Montgomery County v. Public Utility Commission, 438 N.W.2d 111, 113 (Ohio Sup. Ct. 1982).

In general, the property value on which rates are based is the value of the property that is "used and useful for the service and convenience of the public." ORC 4909.04. The property value must be determined as the original cost of property used and useful as of "the date certain determined by" the PUCO. ORC 4909.05(C) and 4909.15(A)(1). See, e.g., Office of Consumer's Counsel v. Public Utility Commission, 423 N.E.2d 820., 827 (Ohio Sup. Ct. 1981) (holding that PUCO lacked statutory authority to treat expenditures for cancelled nuclear plant as amortized operating costs because, even though the investment decision and decision to cancel were prudent when made, the expenditures were "an investment that never provided any service whatsoever to the utility's customers"); and Office of Consumer's Counsel v. Public Utility Commission, 391 N.E.2d 311 (Ohio Sup. Ct. 1979) (rejecting inclusion in rate base of investment in nuclear plant that was not providing beneficial service to ratepayers as of the date on which utility property was valued for rate purposes, although the plant provided beneficial service as of a later date). Including investment in cancelled plant in the rate base shifts the "risk of plant failure from the utility's investors to the ratepayers." Id. at 315. The PUCO may take into account the increased risk to investors that results from the inability to recover costs of cancelled plant. Office of Consumer's Counsel v. PUC, 447 N.E.2d 749, 753-54 (Ohio Sup. Ct. 1983).

However, the PUCO may include in rates an "allowance for construction work in progress" up to 10 percent of the total valuation of the project involved. Prior to its repeal effective January 1, 2001, the provision limited the allowance to 20 percent of the total valuation if the project was for pollution control equipment.[128] ORC 4909.15(A)(1). This allowance may be included in rates for no more than 48 months, with the possibility of an extension of up to 12 more months for good cause. If the project is cancelled, abandoned, or terminated, then the allowance must be excluded from rates "immediately" and offset against future revenues. Id.

Before its repeal effective January 1, 2001 , ORC 4913.05 provided another exception to a strict "used and useful" requirement. If the PUCO approved a plan for compliance with certain requirements of the Acid Rain Program under Title IV of the Clean Air Act, the company incurred costs for emissions control equipment under the plan, and the PUCO subsequently withdrew approval of the plan due to "substantial or extraordinary changes in circumstances," then the PUCO could approve recovery of "reasonably incurred" costs for the equipment.[129]

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[128] Illinois, another coal state that has now deregulated retail electricity sales, had a similar provision for recovery of cost of capital for construction work in progress for "pollution control devices." 220 ILCS 5/9/220(f).

[129] Pennsylvania, another coal state that has now deregulated, had a provision for commission review and approval of each utility's plan, upon request by the utility, to bring coal-fired units into compliance with the Acid Rain Program. 66 PCS 530(a)and (b). Upon approval of the plant, reasonable and prudent compliance costs for "desulfurization devices, clean coal technologies, or similar facilities designed to maintain or promote" (66 PCS 530(d)(2)(ii)) coal use were "recoverable costs of service" (66 PCS 530(d)(2)). Such costs qualified as

ORC 4913.05(G) (repealed effective January 1, 2001). The provision in ORC 4913.05 was apparently never applied.

Prior to repeal of the adjustment clause provisions effective January 1, 2001, the PUCO could allow pass-through of fuel costs and purchased power costs in a fuel adjustment clause. See ORC 4905.01(G) (definition of "fuel component"; repealed effective Jan.1, 2001) and 4909.15.9 (limiting purchased power costs to fuel used for generation; repealed effective Jan. 1, 2001); see also Office of Consumers' Counsel v. Public Utilities Commission, 384 N.W.2d 245 (Ohio Sup. Ct. 1978) (upholding inclusion of full cost of purchased power in fuel adjustment clause); Montgomery Count Board of Commissioners v. Public Utilities Commission, 503 N.E.2d 167 (Ohio Sup. Ct. 1986) (holding that costs other than fuel costs delineated in statute cannot be recovered in fuel adjustment clause); and Cleveland Electric Illuminating Co., 154 PUR4th 418, 1994 WL 526118 (PUCO Aug. 10, 1994) (rejecting inclusion of demand-side management costs in fuel adjustment clause because of insufficient "nexus" between demand-side management programs and reduction in per unit fuel costs and explaining that without such a "nexus" requirement any equipment that increased fuel efficiency could be included in fuel adjustment clause). The PUCO required electric utilities to make a showing every six months, at an expedited hearing, that the fuel costs were "fair, just, and reasonable." OAC 4901:1-11-11(B). The PUCO could defer inclusion of costs in the fuel component if their appropriateness was "questionable," pending submission of evidence that they were "properly includable." OAC 4901:1-11-08(B). The PUCO was required to review the fuel component at least annually, or upon request, when changes in acquisition and delivery costs or in system operations caused or could cause at least a 20 percent change in the fuel component. ORC 4905.30.1 (repealed effective Jan. 1, 2001).

Ohio coal research and development costs could also be included in the fuel component.[130] ORC 4905.31 and 4909.19.1(B) (repealed effective January 1, 2001); see also OAC 4901:1-11-03(B). The Ohio Coal Development Office is charged with encouraging, promoting, and supporting "siting, financing, construction, and operation of commercially available or scaled

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"nonrevenue-producing investments" that were not required, under 66 PSC 1315, to be "used and useful" in order to be included in rate base or otherwise included in rates. 66 PCS 530(d)(3).

130 Illinois similarly allowed inclusion as a fuel cost, recoverable in a fuel adjustment clause, "any fees paid by the utility for the implementation and operation of a process for desulfurization of the fuel gas when burning high sulfur coal at any location" in Illinois. 220 ILS 5/9-220(a).

facilities and technologies, including, without limitation, commercial-scale demonstration facilities and, when necessary or appropriate to demonstrate the commercial acceptability of a specific technology, up to three installations within this state utilizing the specific technology, to more efficiently produce, beneficiate, market, or use Ohio coal." ORC 1551.32(A). Priority is to be given to technologies that "enable maximum use of Ohio coal in an environmentally acceptable, cost-effective manner." ORC 1551.32(B). The Ohio Coal Development Office reviews proposals for coal research and development projects to be supported by a state loans, load guarantees, or grants and may recommend recovery of the costs of such a project through the utility rates. [131] While, on the face of the statute, this seems to be limited to projects undertaken by a gas or natural gas company (ORC 4905.30.4), the costs could be recovered by an electric utility as well through its fuel component. See OAC 4901-11-05. However, it does not appear that any electric utility requested recovery of any coal research and development costs in a fuel adjustment clause. But see East Ohio Gas Co., 1994 WL 73500 (PUCO Feb. 3, 1994) (approving recovery of gas utility's costs in gas reburn and sulfur dioxide and nitrogen oxide control projects at electricity generating plant as coal research and development costs included in adjustment clause).

The electric utility had to charge its most recently approved fuel component until the PUCO changed the fuel component. OAC 4901:1-11-12. After determining the fuel component through an expedited hearing, the PUCO would adjust the rates to reflect the approved fuel component. ORC 4909.19.1(E) (repealed effective January 1, 2001). The fuel component was calculated based on base period fuel costs and purchased power costs (i.e., fuel used to generate purchased power or total purchased power costs for power not exceeding the utility's incremental fuel cost for its own generation). OAC 4901:1-11-01(I) (definition of "economic power") and 4901:1-11-04(B) through (D). A reconciliation procedure was used to reconcile any over- or under-recovery of costs. OAC 4901:1-11-06.

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[131] Pennsylvania similarly had provisions favoring the use of coal, e.g., a provision for inclusion in rate base of construction work in progress for up to 50% of the cost of increasing the capacity to use coal in existing coal-fired plants. 66 PCS 514(c). In addition, the Pennsylvania Public Utility Commission was required to issue regulations requiring utilities to increase their generating capacity through increased capacity to use coal at existing coal-fired facilities where "economically feasible" and "beneficial to ratepayers" and establishing a "special cost recovery and shared benefits procedure" as an incentive for such capacity increases. 66 PCS 514(a) and (b). The Commission also had to order conversion of existing oil- or gas-fired units to coal or coal-derived fuel, unless conversion was not feasible, the converted unit could not meet present or reasonably anticipated environmental requirements, or the converted unit would be more costly to ratepayers. Reasonable and prudent costs of a required conversion were recoverable, even if the conversion or operation of the converted unit was "ultimately prevented by factors beyond the utility's control," and could be included in rate base during construction. 66 PCS 517(a)(and (d). Finally, a public utility could construct a new nuclear-fueled or oil- or gas-fueled unit only with Commission approval. The Commission could approve such construction only if no sites were reasonably available for a comparable unit using coal or coal-derived fuel in compliance with environmental requirements or if such comparable unit would be more costly for ratepayers. 66 PCS 519 and 521.

Ohio's competitive retail electric service statute makes the above-described regulatory regime inapplicable to retail electric service starting in 2001 and requires functional unbundling of electricity distribution from electricity generation and transmission. The Ohio legislature stated that it is state policy to, inter alia: "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service" (ORC 4928.02(A)); "[e]ncourage innovation and market access for cost-effective supply- and demand-side retail electric service" (ORC 4928.02(D)); and "[e]nsure effective competition in the provision of retail electric service by avoiding anti-competitive subsidies" (ORC 4928.02(G)). The shift to deregulated retail electric service is phased in, with a five-year transition period ("market development period") in which costs associated with deregulation may be recovered.

"Retail electric service" is defined as any service "involved in supplying or arranging for the supply of electricity to ultimate consumers" in Ohio, from "the point of generation to the point of consumption." ORC 4928.01(27). This includes generation, aggregation, power marketing, power brokerage, transmission, distribution, ancillary service, metering, and billing and collection. Id. Of these components of retail electric service, the portion that is required by statute to be "competitive" includes "retail electric generation, aggregation, power marketing, and power brokerage services." ORC 4928.03. The PUCO may determine that additional components of retail electric service must also be competitive. ORC 4928.04.

Starting January 1, 2001, "competitive retail electric service" is not subject to "supervision or regulation" by the PUCO under ORC 4901 through ORC 4909 (which are the provisions establishing the above-described more traditional rate regulatory regime) with limited exceptions concerning, e.g., discriminatory rates and conditions, certified territories, and service reliability and public safety. Control of transmission facilities in Ohio must be transferred to qualifying independent transmission entities. ORC 4928.12. Further, each electric utility (e.g., each electric light company engaged in both competitive and noncompetitive retail electric service) must implement a "corporate separation plan" approved by the PUCO. ORC 4928.17(A). The plan must: include the provision of competitive retail electric service through a "fully separated affiliate"; ensure that the company will not extend "undue preference or advantage" to any affiliate, division, or part of its business that supplies competitive retail electric service; and satisfy the public interest in "preventing unfair competitive advantage" and in the "absence of market power." ORC 4928.17(A)(1) through (3). The PUCO may, for good cause, shown, approve a plan that does not provide for a fully separated affiliate but that complies with "functional separation requirements" authorized "for an interim period." ORC 4928.17(C).

In place of more traditional rate regulation for competitive retail electric service (which includes retail electricity generation and sales), Ohio statute requires that each electric distribution utility (i.e., each electric utility that provides retail electric distribution service) provide "a market-based standard service offer "of competitive retail electric services within its certified territory (ORC 4928.14(A)) and the option to purchase such services through a "competitive bidding process" (OCR 4928.14(B)). The PUCO must ensure that competitive retail electric service is provided at "compensatory, fair, and nondiscriminatory" prices, terms, and conditions if the PUCO determines that there is a "decline or loss of effective competition" for such service provided by an electric utility. ORC 4928.06(B). The PUCO is authorized to "resolve abuses of market power by any electric utility that may interfere with effective competition." OCR 4928.06(E)(1). In particular, the PUCO may ensure that retail electric generation service is provided "at reasonable rates" in a "transmission constrained area" in a public utility's certified territory if the PUCO finds that the public utility engaged in "abuse of market power" that is "not adequately mitigated" by any "independent transmission entity controlling the transmission facilities." ORC 4928.06(E)(2). The PUCO has not yet had occasion to exercise its authority under ORC 4928.06.

Each electric utility must submit for approval by the PUCO a "utility transition plan." ORC 4928.31(A). The plan includes the major components for the transition to competitive retail electric service. First, the plan must include a plan for unbundling utility rates, as well as the above-described corporate separation plan. The electric utility is required to file separate (i.e., "unbundled") rate components for electricity generation, transmission, and distribution to be charged during the market development period. ORC 4928.34. During the market development period, the company functions as the provider of last resort in that the company is required to make available to all retail customers in the company's certified territory "a standard service offer of all competitive retail electric services necessary to maintain essential electric service including a firm supply of electric generation service." ORC 4928.35(D). If another supplier fails to provide service, the suppliers' retail customers default to the standard service offer until the customers chose another supplier. Id. In order for the unbundled rates to be approved, the total revenue from all unbundled rates must be capped and equal the total revenues from the company's most recent bundled rates. ORC 4928.34(A). See also ORC 4928.34(A)(1) through (7).

Second, the utility transition plan may include an application for the opportunity to receive revenues for transition costs. During the market development period, the electric utility receives such revenues from competitive retail electric service in its certified territory through: the approved, unbundled rates paid by its customers for retail electric generation; and an approved, "nonbypassable and competitively neutral transition charge" paid, per kilowatthour purchased, by those customers in its certified territory who obtain retail electric generation from another company. ORC 4928.37(A)(1)(b). The transition charge is not payable on electricity supplied by a municipal utility to retail customers if the municipal utility provides transmission or distribution through its facilities and was operating as of January 1, 1999. The charge is also not payable on electricity produced and consumed in Ohio by a self-generator (i.e., a facility producing electricity "primarily for the owner's consumption (ORC 4928.01(33))). ORC 4928.73(A)(2).

In essence, the nonbypassable charge is a charge for access to the wires by retail customers. The only costs that may be included in the transition charge are the "just and reasonable transition costs" that: were "prudently incurred"; "legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service" in Indiana: and are "unrecoverable in a competitive market" but otherwise recoverable by the company. ORC 4928.39(A) through (D). These costs include costs of "regulatory assets," which are unamortized expenses whose recovery was deferred by the PUCO (e.g., deferred taxes). ORC 4928.39. The transition charge includes "shopping incentives" to encourage the development of effective competition in retail electric generation service, e.g., sufficient incentives to induce shifting to a company other than the electric utility by at least 20 percent of the retail electric service load by the end of 2003. ORC 4928.40(A). The transition charges may be reviewed at least annually. ORC 4928.40(B)(1). The portions of the charge that are based on regulatory assets is subject to adjustment only prospectively and generally only after December 3, 2004. ORC 4928.39.

The nonbypassable charge provides an opportunity for the utility to recover transition costs, but actual revenues from the charge may be more or less than these costs. AK Steel Corp. v. Public Utility Commission, 765 N.E.2d 862 (Ohio App. 2002). The electric utility is "wholly responsible" for "how to use" transition revenues and for "whether it is in a competitive position" after the market development period. ORC 4928.38. However, the PUCO may impose requirements to ensure that the revenues are used to "eliminate the allowable transition costs" during the market development period and are not available for use to achieve undue competitive advantage by the electric utility. ORC 4928.39.

Third, the utility transition plan may include a plan for transferring control of the electric utility's transmission facilities to an independent entity. ORC 49028.31(A). In the absence of an approved independent transmission plan, the PUCO must order transfer of the transmission facilities to an independent entity to be operational by the end of 2003. ORC 4928,35(G).

The PUCO has approved utility transition plans for a number of electric utilities. Under these approved plans, the electric utilities were generally allowed to retain ownership of their electricity generating plants, transfer control of transmission, and recover transition costs through a nonbypassable transition charge. See, e.g., Monogahela Power Co., 2000 WL 1873291 (PUCO Oct. 5, 2000) (approving utility transition plan with transfer of operational control of transmission assets to regional transmission organization and with transition charge for regulatory assets but not stranded generation assets); Columbus Southern Power Co., 2000 WL 1873290 (PUCO Sept. 28, 2000) (approving utility transition plan with transfer of operational control of transmission assets to regional transmission organization and later transfer of ownership of transmission and distribution assets to new affiliates and with transition charge for regulatory assets and (except with regard to switching customers) stranded generation assets); Dayton Power and Light Co., 2000 WL 1751554 (PUCO Sept. 21, 2000) (approving utility transition plan with transfer of operational control of transmission assets to regional transmission organization and later transfer of ownership of transmission and generation assets to affiliates and with transition charge for regulatory assets); Cincinnati Gas & Electric Co., 2000 WL 1751385 (PUCO Aug. 31, 2000) (approving utility transition plan with conduct of competitive retail service through affiliate and later transfer of ownership of generation assets and with transition charge for regulatory assets (including future purchased power costs) but not for stranded generation assets); and First Energy Corp., 203 PUR4th 102, 2000 WL 1791792 (PUCO Jul. 19, 2000) (approving utility transition plan with transfer of operational control of generation assets to business unit and later division of ownership of company assets among generation, transmission and distribution, and support services affiliates and with transition charge for regulatory assets and stranded generation assets).

After the market development period (which terminates by the end of 2005 or sooner, if approved by the PUCO), the electric utility may no longer receive "transition revenues" or "equivalent revenues." ORC 4928.38. However, the PUCO may allow recovery of revenue requirements for regulatory assets through December 31, 2010. ORC 4928.20(A). Also after the market development period, each electric utility must provide, "on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service" (ORC 4928.14(A)) and the option to purchase competitive retail electric service at a price determined through a "competitive bidding process" in which any generation supplier may participate (ORC 4928.14(B)). See Dayton Power and Light Co., 227 PUR4th 1, 2003 WL 22142843 (PUCO Sept. 2, 2003) (noting that PUCO had approved ending market development period on December 31, 2003, but extending period to December 31, 2005 due to lack of effective competition and approving negotiated rates in lieu of competitive bidding), rehg. den. in relevant part, 2003 WL 22964799 (PUCO Oct. 22, 2003). The electric utility is the provider of last resort in that, for its certified territory, if another supplier fails to provide electricity generation service for retail customers, service must be provided under the electric utility's standard service offer. There is no time limit on the requirement to function as the provider of last resort. ORC 4928.14(C). An electric distribution utility may require, pursuant to an approved tariff, a retail electric generation service provider to "issue and maintain a financial instrument" to project against default in the provision of retail electric generation service. OAC 4901:1-24-08(A).

The PUCO has interpreted the provider-of-last resort requirement as providing a basis for imposing certain costs related to an electric utility's electricity generating plants on all retail electric generation customers, including those customers served by other electricity suppliers. Dayton Power and Light, 227 PUR4th 1, 2003 WL 22142843 (stating that utility has "costs that are associated with possible return of customers" and should be "compensated for these costs"). The costs (in that case, costs reflecting fuel price increases, compliance with environmental and tax requirements, and physical security and cyber-security) were allowed to be recovered up to a capped amount, through a rider (i.e., a "rate stabilization surcharge"). The PUCO stated that, while it was not finding that these costs were provide-of-last resort costs, "the existence of [provider-of-last-resort] costs makes it reasonable to apply the [surcharge] to all customers."

One electric utility has argued before the PUCO that the company should be able to pass through, in a nonbypassable charge, the costs of investment in electricity generating plant necessary to maintain a specified electricity generation reserve margin. According to the electric utility, this charge will compensate for the company's statutory obligation, as the provider of last resort, to stand ready at all times to serve all retail load in its certified service territory. Initial Comments of the Cincinnati Gas & Electric Company, Case No. 03-93-EL-ATA at 8-16 (Mar. 4, 2003). The PUCO has not yet ruled on the company's request.

The PUCO may also establish riders on the rates for retail electric distribution service. The riders may cover costs for assistance to low income customers or consumer education or costs for an energy efficient revolving loan fund. ORC 4928.61; and ORC 4933.83. Like the nonbypassable charge for transition costs, the riders are wires access charges paid by retail customers. Ohio law does not appear to currently authorize nonbypassable wires charges for any other types of cost.

5.22. Texas.

Until January 1, 2002 when the Public Utility Commission of Texas (TPUC) began to implement "customer choice" under the state's utility deregulation statute, Texas followed a more traditional approach of regulating electric utilities as vertically integrated monopolies. The TPUC is granted "general power to regulate and supervise the business of each public utility", including each "electric utility" (TUC 14.001), and specifically has jurisdiction over "rates, operations, and services of an electric utility" (TUC 32.001). The term "electric utility" is defined generally as any person that "owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state." TUC 31.002(1). However, there are several exceptions to the general definition, including a municipality, a qualifying facility, an exempt wholesale generator, a power marketer (i.e., a person who owns electricity for wholesale sale but owns no generation, transmission, or distribution facilities in the state and has no certificated service areas), and a person owning or operating equipment "used primarily to produce and generate" electricity for his own consumption. (As discussed below, the state's utility deregulation statute amended the definition of "electric utility" add exclusions for a "retail electric provider" and a "power generation company.") Each municipality regulates local utility service within the municipality, with the TPUC exercising a review function, but municipalities may elect to have the TPUC exercise original jurisdiction over such utility service. TUC 33.002 and 33.052.

An electric utility may not provide service to the public "under a franchise or permit" unless the company first obtains a certificate of convenience and necessity. TUC 37.051(a). The TPUC may issue a certificate for a service area (or a facility) only if "necessary for service, accommodation, convenience, or safety of the public." 16 TAC 25.101(c). Further, a "retail electric utility" may not provide service to an area where another "retail electric utility" is lawfully providing service unless the former company first obtains a certificate of convenience and necessity. TUC 37.051(b). The TPUC may not grant a certificate if that would result in an area being "multiply certificated" unless the certificate holder is not providing adequate service. TUC 37.060(h).

Until the provisions were repealed effective September 1, 1999, Texas statute required each electric utility to submit a preliminary, ten-year integrated resource plan that included a forecast of future demand and the supply-side resources needed to meet that demand. TUC 34.021 and 34.022. After the plan was approved, the electric utility had to solicit bids in accordance with the plan and could receive bids from affiliates and request a certificate of "convenience and necessity" for "new rate-based generating plant." TUC 34.051(b)(2). If bid solicitation and negotiation did not result in the resources necessary to meet supply-side needs under the plan, the utility could apply for a certificate of public convenience and necessity for a "utility-owned resource addition" not in the plan. TUC 34.056.

After completion of the solicitation and negotiation process, the electric utility had to submit a proposed, final integrated resource for review by the TPUC. In ruling on the plan, the TPUC had to determine, inter alia, whether to certify the contracts resulting from the solicitations and negotiations and whether to grant a certificate of public convenience and necessity for utility-owned resource additions. TUC 34.103. If the contract involved was between a utility and its affiliate, the TPUC had to consider such factors as whether the transaction provided the affiliate with an "unfair competitive advantage by virtue of its affiliation or association with the utility." TUC 34.104(b)(4). Once a contract was certified, the TPUC had to treat payments under the contract as a "reasonable and necessary operating expense" for purposes of setting rates, and the TPUC could provide for "monthly recovery" of costs under the contract "as those costs [were] incurred." TUC 34.104(c). In determining whether to grant a certificate, the TPUC had to consider several factors, including "environmental integrity" (TUC 34.105(D)) and improvement of service or lowering of cost (TUC 34.105(E)). The TPUC had to grant the certificate if the resource addition was "necessary" under the final integrated resource plan, the resource addition was the "best and most economical chose of technology for the service area," and cost effective conservation or alternative energy resources could not "reasonably meet the need." TUC 34.105(b)(1) through (3). An electric utility could add new resources outside the solicitation process consistent with the "last approved integrated resource planning goals." TUC 34.151(a).

The TPUC must ensure that the rates of an electric utility are "just and reasonable." TUC 36.003(a). An electric utility must give notice of a proposed rate change at least 35 days before the effective date of the new rate. TUC 36.102. The TPUC may suspend the rate change for up to 150 days after the date that the rate change would otherwise be effective. Thereafter, the rate may go into effect subject to refund if the electric utility provides a surety bond payable to the TPUC. TUC 36.108 and 36.110.

In setting rates, the TPUC must approve rates that provide "overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses." TUC 36.051. The TPUC may not allow, as an expense or capital costs, any payment to an affiliate unless the TPUC finds, inter alia, that the price is not higher than the price charged by the affiliate to another affiliate or to a nonaffiliate for the same item. TUC 36.058. These rates must be based on the cost of providing service in a historical test year, adjusted for "know and measurable" changes. 16 TAC 25.231(a). See Suburban Utility Corp. v. Public Utility Commission, 652 S.W.2d 358 (Tex. Sup. Ct. 1983) (upholding adjustments to test period data in order to make them representative of future costs). Further, in setting the rate of return, the TPUC must allocate tax savings, e.g., from accelerated depreciation and investment tax credit, between consumers and the utility based on an equitable balancing of the interests of present and future customers. 16 TUC 36.059(a)(1) and (2). However, rates must reflect taxes actually paid. See Houston Lighting & Power Co., 748 S.W.2d 439, 442 (Tex. Sup. Ct. 1987).

Moreover, the TPUC must consider the electric utility's cost of capital, which comprises the actual cost of debt, the actual cost of preferred common stock, and, for common stock, a "fair return on its market value." 16 TAC 25.231(1)(c)(ii). The TPUC is not authorized to reduce a rate of return otherwise found to be reasonable in order to penalize a utility for mismanagement. Public Utility Commission v. Houston Lighting & Power Co., 715 S.W.2d 98, 104 (Tex. App. Austin 1986), rev. in part on other grounds, 748 S.W.2d 439 (Tex. Sup. Ct. 1987).

In addition, rates must be based on the "original cost," less depreciation, of property that is "used and useful" in providing service. TUC 36.053(a); see also 16 TAC 25.231(c)(2)(A). See Cities for Fair Utility Rates, 924 S.W.2d at 936-37 (upholding inclusion in rate base of usable portion of costs of uncompleted plant held for future use, where utility had specific plans to use the plant within 10 years and where nonusable portion was excluded from rate base and amortized, in order to provide incentive for utility to avoid higher future plant acquisition costs through advance planning and acquisition); and Texas v. Public Utility Commission, 883 S.W.2d 190 (Tex. Sup. Ct 1994) (upholding inclusion in rate base of cost of capital during period from in-service date of plant until effective date of new rates that include plant in rate base). However, as an "exceptional form of rate relief," the TPUC may include in the rate base an electric utility's capital investment in construction work in progress "only if the utility demonstrates that inclusion is necessary to the utility's financial integrity." TUC 36.054(a). Inclusion of construction work in progress in the rate base cannot be used for a "major project" to the extent the project has been "inefficiently or imprudently planned or managed." TUC 36.054(b). See also 16 TAC 25.232(c)(2)(D).

Finally, the TPUC may allow rates to include adjustment clauses for fuel costs and for purchased power costs. TUC 36.203 and 36.205; see also TUC 36.204(1) (authorizing the TPUC to allow "timely recovery" of reasonable purchased power costs) and 16 TAC 25.238. An electric utility can file a petition to update the charge under the fuel adjustment clause as often as every six months and must show that the fuel costs and electricity sales on which the proposed fuel charge is based are reasonable estimates. 16 TAC 25.237(a)(2) and (c). However, an electric utility may file an emergency revision to the fuel charge. The TPUC must issue an order on a fuel-charge petition within 60 days, if no hearing is requested within 30 days of the filing, or 90 days, if a hearing is timely requested. 16 TAC 25.237(e) and (f). Every one to three years, the electric utility must file a petition for reconciliation of fuel expenses and show that the fuel expenses were "reasonable and necessary expenses incurred to provide reliable electric service." 16 TAC 25.236(d).

In 1999, Texas statute was amended to provide for competitive retail electric service starting January 1, 2002. Companies providing electric generation or retail electric service were exempted from the requirements of the above-described regulatory system by adding exemptions to the definition of "electric utility" for a "retail electric provider" (i.e., a person who sells electricity to retail customers and does not own or operate generation assets) and "a power generation company" (i.e., a person who generates electricity for wholesale sale, does not own transmission or distribution facilities, and does not have a certificated service area). TUC 31.002(6).

Each electric utility is required to separate its business activities into a power generation company, a retail electric provider, and a transmission and distribution company by January 1, 2002. This can be done by creating affiliate companies or nonaffiliate companies or by selling assets to third parties. A plan to accomplish the business separation must be filed with the TPUC by January 10, 2000. TUC 39.051. Underpinning Texas' decision to restructure the electric industry was the legislative finding that "regulation was no longer warranted, except for regulation of transmission and distribution services and regulation of the recovery of stranded costs." City of Corpus Christi v. Public Utility Commission, 51 S.W.3d 231, 237 (Tex. Sup. Ct. 2001).

There are additional requirements aimed at promoting competition in electricity generation and thus in retail electricity generation and sales. Each electric utility is required to sell by auction, within 60 days of commencement of customer choice, entitlement to at least 15 percent of the company's installed generation capacity in Texas. In addition, the requirement to sell the entitlements continues until the earlier of five years after commencement of consumer choice or the date that nonaffiliated retail electric providers supply 40 percent of the amount of electricity consumed by residential and small commercial customers in the affiliated transmission and distribution company's certificated service area before customer choice commenced. Only entities not affiliated with the electric utility and authorized to sell electricity in Texas may buy the entitlements. The entitlement may be resold, except not to a retail electric provider affiliated with the auctioning electric utility. TUC 39.153. Also, as of January 1, 2002, a power generation company may not own or control (directly or through an affiliate) more than 20 percent of "installed generation capacity located in, or capable of delivering electricity to, a power region." TUC 39.154(a). Excluded from the generation capacity owned or controlled is capacity made available for auction under TUC 39.153. Included in the power region's installed generation capacity is any "potentially marketable electric generation capacity," e.g., any capacity for self-generation and any capacity interconnected with a transmission or distribution system. TUC 39.154(d). An electric utility or power generation company whose share of installed generation capacity exceeds the 20 percent limit must file a market power mitigation plan for meeting the limit. The TPUC must approve, modify, or reject the plan within 180 days but may not require "divestiture." 16 TAC 25.90(e). The TPUC must monitor companies' shares of installed generation capacity in order to ensure that the percentage limit is not exceeded. TUC 39.157(c).

Retail electric rates were frozen during 1999-2001. During that period, utilities with stranded costs could mitigate them by shifting depreciation relating to transmission and distribution assets to generation assets and by retaining earning in excess of allowed rate of return. See TUC 39.256 and 39.257. Thereafter, starting January 1, 2002, each retail electric customer in the state must have "customer choice" with unregulated retail electric rates, except for customers of cooperatives and municipal utilities that do not opt for "customer choice." TUC 39.102(a). An affiliated retail electric provider of an electric utility serving a retail customer on December 31, 2001 may continue to serve that customer until the customer chooses a different provider. TUC 39.102(b). During the period 2002-2007, an affiliated electric provider must offer, to residential and small commercial customers of its affiliated transmission and distribution company, rates (referred to as "price to beat") that are 6 percent less than the rates as of January 1, 1999. The price to beat must be charged until the earlier of three years after the commencement of customer choice or the date on which, according to the TPUC, 40 percent of the power consumed by the customers (residential or small commercial customers as applicable) in a given certificated service area is provided by nonaffiliated retail electric providers. TUC 39.202(e).

By June 1, 2001, the TPUC had to designate retail electric providers in customer choice areas as "providers of last resort." TUC 39.106(a). If no retail electric provider applies to be the provider of last resort for a given area on reasonable terms and conditions, the TPUC may require a retail electric provider to take on that function. TUC 39.106(f). In general, the TPUC designates providers of last resort through competitive bidding. The TPUC will solicit bids for two-year terms. If no eligible bids are received, then the TPUC will select the provider of last resort by lottery. 16 TAC 25.43(g)(2). But see Residential, Small Nonresidential Customers, 2001 WL

34063712 (TPUC Dec. 7, 2001) (approving designation of providers of last resort and providing for review and adjustment of provider-of-last-resort rates to ensure there is neither windfall nor net financial loss). A provider of last resort must offer a standard retail electric service package with a fixed, nondiscountable rate approved by the TPUC. See Residential, Small Nonresidential, 2001 WL 1834071 (TPUC Aug. 13, 2001) (holding TPUC has authority to approve reasonable provider-of-last-resort rate). The standard package must include "basic firm service" (16 TAC 25.43(d)(3)), i.e., service that is "not subject to interruption for economic reasons" (16 TAC 25.43(c)(1)). If a customer of another retail electric provider does not receive service by such provider, then the provider of last resort must offer the customer the standard retail electric service package. TUC 39.106(g). The provider of last resort is responsible for obtaining the resources and services "needed to serve" the customers for which it is responsible. 16 TAC 25.43(n)(4). After its term as the provider of last resort ends, the company may continue to provide retail electric service to such customers who do not choose another provider. 16 TAC 25.43(o)(3).

Texas statute establishes a mechanism for electric utilities to recover stranded costs that result from deregulation of retail electric service. Specifically, an electric utility "is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service." TUC 39.252(a). See City of Corpus Christi , 51 S.W.3d 231 (upholding constitutionality of allowing recovery of stranded costs through transition charges). "Stranded costs" are defined as the "positive excess of net book value of generation assets over the market value of the assets." TUC 39.251(7). Book value is determined as of the earlier of December 31, 2001 or the date on which the market value of generation assets is established a market-based methodology. TUC 39.262(h). An electric utility using the stranded cost recovery mechanism must take action to reduce the amount of such costs. TUC 39.254. An electric utility with no stranded costs must use revenues in excess of costs for capital expenditures to improve or expand transmission or distribution or to improve air quality. TUC 39.255(a).

By April 1, 2000, each electric utility must submit rates for transmission and distribution service. In particular, the electric utility must develop a nonbypassable delivery charge that is the sum of : a transmission and distribution charge based on a "forecasted 2002 test year"; a "system benefit fund fee; and an "expected competition transition charge" reflecting stranded costs projected as of December 31, 2001. TUC 39.201(b). The TPUC will determine the period over which stranded costs may be recovered. In order to recover the costs reflected in the expected competition transition charge, the electric utility may implement a nonbypassable competition transition charge including up to 100 percent of the company's stranded costs, may implement a transition charge under a "financing order" of the TPUC that allows the company to "securitize" most of charge, or may implement a combination of these approaches. TUC 39.201(i). Recovery of an electric utility's stranded costs will be from all existing or future retail customers in the company's certificated service area as of May 1, 1999. Moreover, if a customers has new (i.e., post 1999) on-site generation greater than 10 MWe, available without the use of the electric utility's transmission or distribution facilities, and from which the customer starts taking electricity that "materially reduces" its purchase of electricity, a competitive transition charge will be paid by the customer based on the output of the on-site generation. TUC 39.252(b)(2). A "material reduction" in electricity purchases is defined as a reduction of 12.5 percent or more. 16 TAC 25.345(i)(4). There is an exception if a customer's load was served by a fully operational qualifying facility before September 1, 2001. In that case, the charge will only be imposed for services actually provided by the transmission and distribution utility. TUC 39.262(k).

After January 10, 2004, the affiliated power generation company, transmission and distribution utility, and retail electric provider must jointly file final stranded costs and reconcile these costs with the estimated stranded costs used to set the competitive transition charge. TUC 39.262(c). Based on this filing the TPUC will review the stranded cost estimate and make adjustments to reflect the final costs. The companies will not be permitted to over-recover stranded costs. 16 TAC 25.263(a)(1). To the extent the estimated costs exceed the final costs, the TPUC may reduce the company's cost recovery to reflect the difference, e.g., by reducing the competition transition charge to the extent that the costs are not included in a securitized transition charge or reducing the transmission and distribution utility's rates. TUC 39.201(l) and 39.262(g). To the extent estimated costs are less than the final costs, the TPUC may increase the nonbypassable delivery charge or extend the period over which it is applied. Id.

Finally, Texas statute establishes procedures under which an electric utility may "securitize" its stranded asset recovery by selling transition bonds supported by such recovery. At the request of an electric utility, the TPUC must issue a "financing order" if the TPUC finds that total revenues to be collected under the financing order are less than the revenue requirement recovered over the remaining life of the stranded assets "using conventional financing methods." TUC 39.303(a). The financing order must approve a "transition charge" for stranded costs that is recoverable in the same manner as the "competitive transition charge" and is "nonbypassable." TUC 39.303(c) and 39.306. There are streamlined and expedited judicial appeal procedures applicable to TPUC financial orders: such orders must be appealed within 15 days to a specified Texas district court, and that court's decision must be appealed within 15 days to the Texas Supreme Court. TUC 39.303(f).

Texas issued a number of financing orders. See, e.g., TXU Electric Co., 1999 WL 33592527 (TPUC Dec. 21, 1999), rev. in part, TXU Electric Co. v. Public Utility Commission, 51 S.W.3d 275 (Tex. Sup. Ct. 2001); Central Power Light Co., 2000 WL 33529579 (TPUC Mar. 27, 2000); and Reliant Energy Inc., 2000 WL 33529581 (TPUC Jun. 1, 2000) (financing orders approving issuance of transition bonds by wholly owned special purpose entity, imposing transition charges for life of bonds on all existing retail customers of utility as of May 1, 1999 and all future retail customers located in certified service (including certain customers with new on-site generation), and requiring utility, retail electric providers, and transmission and distribution providers to collect transition charges for special purpose entity). Each financing order states that it is "final," "not subject to review or appeal" except under the special procedures in TUC 39.303(f), and "binding" on "any successor to the Commission." See, e.g., id.

Once the financing order and the authorized transition charge become final, they are thereafter "irrevocable and not subject to reduction, impairment, or adjustment by further action" of the TPUC, except for an annual true-up. TUC 39.303(d). Under TUC 39.307, the TPUC must conduct at least annually a true-up proceeding to correct for any over- or under-collection of the transition charge and to ensure recovery of amount sufficient to provide timely payments of debt service and other required charges in connection with the transition bonds. See TXU Electric Co., 2002 WL 32077783 (TPUC Jun. 20, 2002) (addressing securitization and true-up).

There is also a series of provisions to ensure that the transition charges are dedicated, and used, to service the transition bonds. For example, the rights and interests of the electric utility under the financing order are "only a contract right" until they are transferred in connection with the issuance of transition bonds, at which time they become "transition property" (TUC 39.304(a)), i.e., "a present property right for purposes of contracts concerning the sale or pledge of property" (TUC 39.304(b)). All revenues from a transition charge constitute "proceeds only of the transition property, even though the imposition and collection of transition charges depends on further acts of the utility or others" (TUC 39.304(b)). Further, the interest in transition property and the revenues from such property are "not subject to setoff, counterclaim, surcharge, or defense" by the electric utility or any other person or in connection with bankruptcy of the electric utility or any other entity. TUC 39.305. Moreover, an agreement transferring transition property and stating that the transfer is "a sale or other absolute transfer" means that the transaction is "a true sale" and "not a secured transaction and that title, legal and equitable, has passed to the entity to which the transition property is transferred." TUC 39.308. In addition, a valid and enforceable lien and security interest in transition property may be created only by a financing order and a security agreement in connection with the financing order. TUC 39.309(b). The lien and security interest is "continuously perfected" upon the filing of a notice with the Texas Secretary of State and takes "precedence over any subsequent judicial or other lien creditor." Id. Finally, Texas pledges not to "take or permit any action that would impair the value of transition property" or to reduce the transition charge (except for true-up under TUC 39.307) until the transition bonds are paid in full. TUC 39.310.

Texas statute provides for an additional nonbypassable charge to retail customers for cost associated with nuclear decommissioning. Those costs "continue to be subject to cost of service rate regulation." TUC 39.205. A nonbypassable charge is also authorized for the system benefit fund, which may be used only for low-income electric customer assistance, customer education, or school funding losses due to electric restructuring. TUC 39.903(e).

Rather than having any special provisions expressly aimed at encouraging clean coal technology, Texas statute expresses a preference for natural-gas-fired electric generation. TUC 39.9044(a) states that it is the intent of the Texas legislature that 50 percent of the generating capacity installed after January 1, 2000 use natural gas. The TPUC is required to establish a program to encourage use of natural gas produced in Texas as "the preferential fuel." Id. In response to this mandate, the TPUC established a program under which a natural gas energy credit is granted for each megawatt of new (i.e., post-January 1, 2000) capacity fueled by natural gas and each power generation company, municipal utility, and electric cooperative must hold natural gas energy credits in an amount not less than its new non-gas-fired generating capacity (except for renewable energy projects). 16 TAC 25.172(d). Natural gas energy credits may be traded. 6 TAC 25.173(f). The TPUC will activate the program based on a determine that within three years new capacity fueled "primarily" by natural gas "may fall below 55 percent of all new generating capacity." 16 TAC 25.172(e). The TPUC may accelerate or delay the program if such action is "in the public interest." Id.

5.3. Effect on allocation of electricity generation investment risk .

The approach adopted by a state toward utility regulation has a significant effect on the allocation of investment risk of new electricity generating projects. In particular, for the reasons discussed in Section 4.2 above, the approach in states using more traditional utility regulation tends to shift some of the construction, operating, and marketing risk to ratepayers so that a significant portion of such risk is borne by ratepayers.

As discussed in Section 5.1 above, Indiana has adopted a series of provisions that provide for sharing the risk of new electric generating plant among investors and ratepayers. Under these provisions, the IURC: reviews and certifies proposed new electricity generating plant and clean coal technology; allows for recovery of cost for capital for IURC-approved construction work in progress prior to completion of the new plant through an adjustment clause; provides an assured revenue stream for recovery of at least some of the capital investment and related cost of capital if the plant is not completed, and provides an assured revenue stream for ongoing recovery, through an adjustment clause, of all of the capital investment, cost of capital, and operating costs if the plant is completed and operational and the costs are IURC-approved.

As discussed in Section 5.1 above, Kentucky has less elaborate procedures that appear to provide more rapid, but perhaps less certain, cost recovery than the Indiana provisions. The Kentucky provisions provide for ongoing recovery of some types of plant costs through an adjustment clause (e.g., capital investment in, and related cost of capital for, emission controls and fuel and purchased power costs). Recovery of cost of capital may commence during construction.

In Ohio and Texas, one result of deregulation legislation is generally to allocate the risk of electricity generating plant to investors, rather than to ratepayers. Costs of electricity generating plant are generally to be recovered through rates determined by the electricity market, rather than through cost-of-service rates determined and imposed by the state PUC. As a result, the risk of electricity generation costs increasing or market electricity prices declining is generally borne by investors.

However, as discussed in Section 5.1 above, in Ohio and Texas certain types of plant costs are to be recovered through nonbypassable charges set by the state utility regulatory commission based on costs and paid by all retail customers based on their access to the distribution system. In particular, with regard to existing electricity generating plant, the portion of capital investment and cost of capital, and operating costs previously incurred, deferred for later recovery, but unlikely to be recovered through market-based rates are passed through in nonbypassable wires charges. The use of nonbypassable charges shifts a significant portion of the marketing risk of existing electricity generating plant to ratepayers to the extent such plant is a stranded asset. It should be noted that, if nonbypassable charges can also be used to recover costs of existing or new electricity generating plant used for provider-of-last-resort service, additional construction, operating, and marketing risk will be shifted to ratepayers. However, it is unclear whether and to what extent plant costs will be treated as provider-of-last-resort costs.

6.0. MODEL STATE MECHANISM FOR REVIEW, APPROVAL AND RECOVERY OF IGCC PROJECT COSTS.

6.1. Model state mechanism for review, approval, and recovery of costs.

The following is a description of an integrated mechanism -- reflecting an amalgamation and coordination of various provisions in several states -- that implements the 3Party Covenant and provides a significant level of sharing of the risk of new electricity generating plant (i.e., new IGCC plants) among investors, ratepayers, and the federal government. As discussed above, the 3Party Covenant comprises the key elements of: private investor provision of equity capital investment in the new IGCC plant; federal guarantee of relatively highly leveraged, nonrecourse debt capital for the new IGCC plant; and state PUC review and provision of an assured revenue stream for IGCC-plant-cost recovery. This model mechanism is premised on the state PUC having jurisdiction to review, approve, and allow recovery of the capital investment, cost of capital, and operating costs for the new IGCC plant and is intended for use in both states with more traditional regulation and states with competitive retail electricity generation and sales. While an effort was made to develop a model mechanism that will fit as closely as possible with existing state regulatory regimes, this mechanism will likely require more extensive legislative changes in the latter group of states.

1. Before any construction begins, the state PUC reviews the company's detailed proposal for the new plant in order to determine whether the plant is in the public convenience and necessity. Determination of the public convenience and necessity will include consideration of several factors concerning the likely benefits and costs of the proposed IGCC plant. Based on a satisfactory determination, the state PUC then issues a certificate of public convenience and necessity for the new plant.

a. Among the factors considered in weighing the benefits and costs of the proposed IGCC plant are: the need for new electricity generating capacity to meet future demand; the need for fuel diversity for electricity generation and the specific fuel that will be used in the new IGCC plant; the projected level, volatility, and reasonableness of costs of capacity and electricity from new IGCC plant relative to alternative sources of electricity; the acceptability of the technology risk of the proposed IGCC plant; the economic feasibility of the proposed IGCC plant; the benefit to ratepayers of the federal loan guarantee; and the effect of the proposed IGCC plant on economic development in the state, particularly any local coal industry. Analysis of the technology risk includes consideration of the extent to which warranties are provided by the equipment manufacturers and the engineering and construction company involved in the project. Analysis of projected IGCC plant costs and economic feasibility reflect, of course, the impact of the 3Party Covenant on cost of capital. Analysis of the effect on local economic development includes consideration of what portion (e.g., 75 percent) of the heat input for the plant will be from coal and the effect that will have on any local coal industry.

b. As part of its review of the plant proposal and issuance of the certificate, the state PUC establishes the cost-of-capital percentage (encompassing interest, preferred stock dividend, and return on common equity) for the project and, as discussed below, approves use of an IGCC fixed-cost adjustment clause and an IGCC variable-cost adjustment clause for future recovery of incurred project costs as the costs are approved. The state PUC must make the cost-of-capital figure (including return on common equity) permanent for life of the project in order to create an assured revenue stream to support the federal loan guarantee under the 3Party Covenant. Any subsequent reduction in the return on common equity will reduce the cushion of debt service and adversely affect the debt investors' risk. [132]

c. As part of its review of the plant proposal and issuance of the certificate, the state PUC also establishes the depreciation and amortization periods for categories of preconstruction and construction expenditures.

2. After issuance of the certificate and as construction progresses, the state PUC periodically (e.g., quarterly or semiannually) [133] conducts on an expedited basis a prudence review of, and approves as appropriate, the portion of the IGCC plant constructed during the preceding review period (e.g., preceding quarter or six months) and the associated preconstruction and construction expenditures. This type of approach is used in Indiana. While under Indiana statute the company may choose between ongoing periodic review and one-time review at the end of the project, ongoing review should be required. The ongoing review process better accommodates both the ratepayers' interest in assurance that costs are prudently incurred at each stage of the project and the investors' interest in the greatest assurance of cost recovery. After issuance of a certificate for the new plant, the company can rely on the certificate and subsequent ongoing review to provide an assured revenue stream for recovery of the capital investment in, and the cost of capital of, the plant.

a. As soon as each portion of preconstruction and construction expenditures for the new plant (i.e., construction work in progress) is approved in the ongoing review during construction, the cost of capital for the approved preconstruction and construction expenditures becomes recoverable on an ongoing basis through, and is reflected in, the approved IGCC fixed-

[132] In determining the cost-of-capital percentage, the state PUC may want to consider a higher return (e.g., up to three percentage points higher as allowed under Indiana statute) for equity capital invested in new plant, as an incentive for construction of an IGCC plant.

[133] While quarterly review results in more expeditious recovery of costs, semi-annual review is less burdensome on the state PUC and may facilitate public participation and more thorough review.

cost adjustment clause. [134] The calculation of the charge under the IGCC fixed-cost adjustment clause is reviewed (on an expedited basis) on the same periodic basis as the state PUC's ongoing review of the expenditures. Recovery is more assured and more timely if accomplished through an adjustment clause with expedited review, instead of through a general rate case.

i. Assuming that ongoing review is conducted, for example, every six months and that the duration of each periodic review proceeding is limited, for example, to three months, the cost of capital will be recovered within three to nine months after incurrence of the associated expenditures. Since most of the cost of capital is recovered on an ongoing basis during construction, a much smaller amount will be accrued, added to the total capital investment in the plant, and ultimately recovered through amortization.

ii. A per-kilowatt-hour charge is calculated under the IGCC fixed-cost adjustment clause based, among other things, on the cost of capital incurred during the review period (e.g., each quarter or six months) and estimated kilowatt-hour sales. The charge for each review period also reflects correction of any difference between estimated and actual kilowatt-hour sales for the previous review period.

b. Instead of structuring review and recovery as set forth above in paragraph 2.a, the state PUC can allow ongoing recovery through the approved IGCC fixed-cost adjustment clause, and updating of the IGCC fixed-cost adjustment clause charge, for the cost of capital before approval of the underlying preconstruction and construction expenditures. For example, the IGCC fixed-cost adjustment clause charge can be updated every month or every three months while the ongoing review is conducted every six months. This type of approach is used in Kentucky for recovery of capital investment, cost of capital, and operating costs associated with certain emission controls.

i. If some of the underlying preconstruction and construction expenditures are not approved in the ongoing review, the IGCC fixed-cost adjustment clause charge can be adjusted in order to credit or refund to retail electric customers the excess cost of capital that was already recovered. This adjustment is similar to the adjustment made to account for the difference between estimated and actual kilowatt-hour sales, discussed above in paragraph 2.a.ii.

ii. Allowing recovery of cost of capital to commence through an adjustment clause before approval of the underlying expenditures reduces even further the portion of the cost of capital that is recovered during construction and therefore the amount that will be accrued and added to the total capital investment in the plant. However, as discussed

[134] As discussed above, precedents for this are found in several state statutes. Indiana statute provides recovery (through an adjustment clause) of cost of capital for construction work in progress for clean coal technology, while Kentucky provides for such recovery for costs of environmental compliance for coal combustion. Similarly, prior to deregulation, Ohio provided recovery of cost of capital for construction work in progress for pollution control equipment, as did Illinois.

below, the federally guaranteed loan will be disbursed, for a given portion of the expenditures, only after review and approval of the portion of the expenditures.

c. As each portion of the preconstruction and construction expenditures is reviewed and approved, future recovery of these costs (including the related cost of capital) cannot be challenged, in the absence of fraud or concealment. For example, issues concerning excessive cost, inadequate quality control, failure to complete plant, or inability of plant to operate properly. In this way, the state PUC's review and protective approval is updated during and after plant construction. This approach is used in Indiana and, coupled with use of adjustment clauses as the recovery mechanism (as discussed below in paragraph 3), provides an assured revenue stream for recovery of preconstruction and construction expenditures and associated cost of capital.

i. Disbursement of the federally guaranteed, nonrecourse loan is coordinated with the ongoing review process. As each portion of the preconstruction and construction expenditures is reviewed and approved for recovery through the approved IGCC adjustment clause, the federally guaranteed loan is disbursed for the debt-funded share of that portion of the expenditures. Such approval minimizes the likelihood of any call on the federal guarantee. Prior to disbursement of the federally guaranteed loan, the company must fund preconstruction and construction expenditures using company resources.

ii. If construction of the new plant is terminated before plant completion or if the plant is not operable, each portion of the preconstruction and construction expenditures that was approved during the ongoing review cannot be challenged and is recoverable. Any portion of these expenditures that was not approved is recoverable only upon a showing that such portion was necessary and prudent and in the absence of fraud, concealment, or gross mismanagement.

iii. Recoverable preconstruction and construction expenditures (including associated cost of capital to the extent it has not already been recovered through return on construction work in progress) are depreciated or amortized over the appropriate period and will be recovered through the approved IGCC fixed-cost adjustment clause.

3. After completion and commencement of operation of the new IGCC plant, the state PUC periodically (e.g., quarterly or semiannually) conducts on an expedited basis a prudence review of the plant's operating costs during the preceding review period (e.g., preceding quarter or six months). Operating costs comprise operation and maintenance, fuel, salaries, and taxes.

a. As soon as the operating costs for each review period are approved in the ongoing review after the commencement of plant operation, the approved operating costs become recoverable on an ongoing basis through, and are reflected in, the approved IGCC variable-cost adjustment clause.

i. Coordinated with the approval and pass-through of operating costs, the depreciation and amortization of the previously approved preconstruction and construction expenditures and the cost of capital associated with such expenditures become recoverable on an ongoing basis through, and are reflected in, the approved IGCC fixed-cost adjustment clause. The calculation of charges under the adjustment clauses is reviewed (on an expedited basis) on the same periodic basis as the state PUC's ongoing review of the operating costs.

ii. The state PUC must require the IGCC plant owner to handle separately the revenue stream from the adjustment-clause charges and place such revenues in a segregated account that is used only to pay IGCC project costs, including cost of capital.

b. Instead of structuring review and recovery as set forth above in paragraph 3.a, the state public utility commission could allow ongoing recovery through the approved IGCC variable-cost and fixed cost adjustment clauses, and updating of the IGCC variable-cost and fixed-cost adjustment clause charges, before approval of the operating costs. For example, the IGCC variable-cost and fixed-cost adjustment clause charges could be updated every month or every three months while the ongoing review is conducted every six months. The process is analogous to that described above in paragraph 2.b.

4. The state PUC decisions under paragraphs 1 through 3 above must be sufficiently binding in the future to be viewed by investors and the federal government as providing an assured revenue stream that supports the federal loan guarantee under the 3Party Covenant.[135]

6.2. Imposition of approved IGCC adjustment clause charges.

In order to support the federal guarantee of debt capital in the IGCC plant under the 3Party Covenant, the approved IGCC adjustment clause charges must be imposed in a way that provides an assured revenue stream for recovery of the approved capital investment, associated cost of capital, and operating costs. In states with a more traditional regulatory approach, this means that charges under the approved IGCC fixed-cost and variable-cost adjustment clauses should be imposed on all retail customers in the service area of the utility that owns or operates the IGCC plant.

In Indiana and Kentucky, each utility that provides retail electricity generation, sales, and distribution service has a specified service area in which the company is responsible for

[135] This issue, summarily addressed in this draft report, warrants further research and consideration for the final report. It seems to be within the authority of a state legislature to adopt provisions making state PUC decisions binding in the future, e.g., on the state PUC. This is because the legislature has general authority to set electric utility rates and may delegate to a state PUC -- with appropriate limitations on such delegation -- full rate-making authority (under a more traditional approach) or more limited rate-making authority (under a competitive approach). Precedents concerning the binding nature of state PUC decisions are provided by Texas statute, which includes special provisions concerning the charges of transition costs that are securitized through transition bonds. See Section 5.22 above.

providing such service for all retail customers. The charges should be imposed on a per-kilowatthour basis, analogous to fuel or purchased power cost charges under an adjustment clause. To the extent that the utility makes wholesale sales from the IGCC plant, the utility's retail customers should be credited for any IGCC plant costs recovered through the wholesale sales. [136]

In states with competitive retail electricity generation and sale, an assured revenue stream for recovery of capital investment and cost of capital will be provided if charges under the approved IGCC fixed-cost adjustment clause are imposed, as a nonbypassable wires charge, on all retail customers in the service area in which the company that owns or operates the IGCC plant is the provider of last resort. In contrast, charges under the approved IGCC variable-cost adjustment clause should be imposed on only the retail customers actually served by that company. This will provide an assured revenue stream for recovery of operating costs because, as discussed above, a new IGCC plant will likely have relatively low operating costs as compared to most other electricity generating plants and so will likely be dispatched ahead of most other plants and be highly utilized.

In Ohio and Texas, retail customers that do not choose a retail electric provider or whose retail electric provider fails to provide sufficient electricity to meet their firm demand are required to be serviced by a provider of last resort. In Ohio, the distribution utility is the provider of last resort, while, in Texas, the provider of last resort is chosen for two year terms through a bidding process or, in the absence of reasonable bids, through lottery or assignment by the TPUC. The provider of last resort is required to have sufficient capacity and electricity to provide firm electric service to these retail customers. The use of the IGCC plant as base load plant necessary for firm electric service may provide a rationale for imposing the approved IGCC fixed-cost adjustment clause on all retail customers in the service area.

However, with competitive electricity generation and sales, some of the retail customers in the service areas of the company that owns or operates the IGCC plant will likely buy electricity from other suppliers. In these circumstances, one approach that has been suggested is to impose the IGCC fixed-cost adjustment clause as a nonbypassable wires charge on all retail customers in the service area, but to give each alternative supplier with retail customers in the service area an entitlement to a share of the IGCC plant's capacity, perhaps in proportion to such supplier's retail-customer load in the service area. However, it should be noted that the provision to alternative suppliers of any entitlement to the IGCC plant capacity may well be viewed as sales for resale, i.e., sales to such alternative suppliers for resale to their retail customers. If that view

[136] How this should be accomplished, and whether there should be different treatment for firm vs. spot wholesales sales, warrant further research and consideration for the final report.

prevails, then the provision of such entitlement may be subject to FERC jurisdiction (unless the IGCC plant is in the ERCOT portion of Texas and sells electricity only in ERCOT).[137]

6.3. State vs. FERC jurisdiction over review, approval, and recovery of costs.

The model state mechanism described above assumes that the state PUC retains jurisdiction to review, approve, and allow recovery of the capital investment, cost of capital, and operating costs for the new IGCC plant. Such jurisdiction is retained if the ownership of the new IGCC plant is structured in a way that avoids sale for resale of the electricity produced by the plant.[138] Interstate sales for resale, as well as interstate transmission, are subject to the jurisdiction of the FERC, rather than the state PUC.

For example, if the IGCC plant is directly owned by a utility that uses all of the electricity generated by the plant to serve the utility's retail customers, then there seems to be no sale for resale of the plant's generation. Under the more traditional approach to utility regulation in Indiana and Kentucky, of course, an electric utility may own (or lease) a new IGCC plant and sell the output to retail customers. Further, it seems unclear whether Ohio statute bars utility distribution companies from owning (or leasing) electricity generating facilities. While electric utilities in Ohio are required to implement a "corporate separation plan" that, inter alia, includes the provision of competitive retail electric service through a "fully separated affiliate"(ORC 4928.17(A)(1)), Ohio electric utilities have not been required to transfer ownership of the electricity generating plants to affiliates or third parties. See Section 5.21 above. It also seems unclear whether Texas statute bars a utility distribution company, functioning as the provider of last resort, from owning (or leasing) electricity generating plant and selling the output to its provider-of-last-resort customers.[139] With IGCC plant ownership by the utility distribution

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137 The recovery of IGCC plant costs through a nonbypassable wires charge and the implications for FERC jurisdiction, which are summarily discussed in this draft report, warrant further research and consideration for the final report.

138 It should also be noted that the structuring of ownership of the new IGCC plant and the identity of the owner may have implications under the Public Utility Holding Company Act. See Energy Industrial Center Study at 342-67 (discussing application of Public Utility Holding Company Act to cogeneration plants). Those implications are not addressed in this draft report but warrant further research and consideration for the final report. It should be noted that proposed legislation is being considered to repeal the Public Utility Holding Company Act.

139 The ability of an electric distribution company, e.g., functioning as a provider of last resort, to own or lease electricity generating plant in Ohio and Texas warrants further research and consideration for the final report.

company, the state PUC has jurisdiction to review, approve, and allow recovery of the capital investment, cost of capital, and operating costs for the plant. [140]

A second alternative arrangement is for the new IGCC plant to be constructed by another company (e.g., an affiliate limited-liability corporation or independent power producer) and leased and operated by the utility that uses all of the plant's generation to serve retail customers.[141] In that case, there does not seem to be any sale for resale of the plant's generation. Instead, the lease may be regarded as purely a rental or financing arrangement for the plant if, for example, the lessor has no operational control over the plant and the rental payments cover only capital investment and cost of capital and are independent of plant availability and the amount of electricity the lessee generates at the plant. See, e.g., Cleveland Electric Illuminating Co., 76 FERC par.61,156, 61,925 (Aug. 2, 1996), reh'g den., 77 FERC par.61,058 (1996) (treating a lease of electricity generating plant as sale for resale where utility owner retains operational control). If the facilities that are leased include both a new IGCC plant and equipment used in transmission of electricity generated at the plant to the transmission system of lessee, the lease may be subject to FERC review under Section 203 of the Federal Power Act, under which the FERC must first approve the sale, lease, or other disposition of jurisdictional (in this case, transmission) facilities as "consistent with the public interest." 16 U.S.C. 824b(a). It seems that FERC Section 203 review of the lease may be avoided by limiting the leased facilities exclusively to the IGCC plant itself, and it is not clear, in any event, how likely that review is to result in disapproval of the lease.[142]

Under a third alternative arrangement where if the new IGCC plant is constructed, owned, and operated by another company (e.g., an affiliate or independent power producer) that sells the plant's generation to the utility, there seems to be a sale for resale. As noted above, except for sales for resale by plants located in the ERCOT portion of Texas to a company that resells to retail customers in that portion of Texas, the rates for sales for resale are subject to FERC jurisdiction.

Under Section 205 of the Federal Power Act, all rates for sales for resale must be "just and reasonable" (16 U.S.C. 824d(a)) and must not result in "undue preference or advantage" or "undue prejudice or disadvantage" (16 U.S.C. 824d(b)).[143] Further, under Section 206, the

[140] However, to the extent the utility distribution company has firm wholesale customers, there may be an issue of whether a portion of the cost recovery for the plant falls within FERC jurisdiction. This warrants further research and consideration for the final report.

[141] As discussed above, it is unclear whether Ohio or Texas statute allows this type of lease arrangement.

[142] Both the scope of FERC jurisdiction over the lease and the likely result of FERC review of the lease warrant further research and consideration for the final report.

[143] In addition, if a seller qualifies as an exempt wholesale generator under 15 U.S.C. 79Z-5a(a)(1), the FERC cannot approve the seller's rates if they result from any "undue preference or advantage" from an associate or affiliate of a

FERC must set just and reasonable rates if it determines, on its own motion or in response to a complaint, that any rate is "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. 824e(a).

The FERC traditionally approved rates based on the seller's cost of service and continues to do so unless the requirements (discussed below) for market-based rates are met. If the rates charged for recovery of the costs of a new IGCC plant are subject to FERC jurisdiction, it is not clear whether or to what extent the FERC will approve cost-of-service rates that include a number of the elements specified in the model mechanism (described in Section 6.1 above for state PUCs) that are necessary to provide an assured revenue stream to support the federal loan guarantee under the 3Party Covenant: e.g., construction-period recovery of cost of capital on construction work in progress, recovery of capital investment and cost of capital for uncompleted plant, and recovery of capital investment and cost of capital through an adjustment clause. It is also not clear whether, in determining cost of service, the FERC will allow additional costs attributable to deployment of new, complex technology (i.e., IGCC) or installation of emission control or other equipment that goes beyond current environmental requirements (e.g., equipment for mercury control or related to carbon sequestration). [144]

The FERC has in the past excluded, from rate base, construction work in progress and expenditures for cancelled plant on the ground that such items were not "used and useful." See NEPCO Municipal Rate Committee, 668 F.2d at 1332-33; and Jersey Central Power & Light, 810 F.2d 1176-76. However, the FERC currently allows rate base treatment for certain types of construction work in progress, i.e., 100 percent of construction work in progress involving pollution control and conversion of plants from oil or natural gas to other fuels and, in some cases, 50 percent of other construction work in progress. See 18 C.F.R. 35.25(c); and Kentucky Utilities Co. v. FERC, 760 F2d 1321, 1322, n.2. (D.C. Cir. 1985). Further, the FERC has allowed some, but apparently not full, recovery of investment in uncompleted electricity generating plant. See, e.g., New England Power Co., 42 FERC par.61,016 (1988) (allowing 50 percent of prudent investment in cancelled nuclear plant to be amortized over expected life of plant, with unamortized portion of that 50 percent portion to be included in rate base). In addition, the FERC has allowed the use of formula rates, similar to an adjustment clause, for recovery of capital investment and cost of capital for completed electricity generating plants, but

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utility. 16 U.S.C. 824m. This does not appear to be significantly different than the requirements that rates be just and reasonable, and not result in undue preference or advantage, under Section 205 of the Federal Power Act. In addition, under 15 U.S.C. 79Z-5a(k), an electric utility company may not enter into an electricity purchase contract from an exempt wholesale generator that is an affiliate or associate, unless the contract is approved by each state having jurisdiction over the retail rates of the electric utility company. FERC and state review under these provisions warrant further research and consideration for the final report.

[144] Although addressed summarily in this draft report, the FERC's policies on these ratemaking and cost-of -service matters warrant further research and consideration for the final report.

with provisions for periodic review of return on equity. See, e.g., Ocean State Power, 38 FERC par.61,140 (1987) and 44 FERC par.61,261 (1988) (approving formula rates for new plants covering capital investment and cost of capital, with provisions putting risk of cost overruns, construction delays, achievement of commercial operation and design capacity, and availability of unit on owner and with requirement for periodic review of return on equity).

Recently, in many cases, the FERC has approved rates based on competitive market rates, instead of cost-of-service rates. See, e.g., Boston Edison Co., 55 FERC par.61,382 at 62,167 (1991). Presumably, if the rates charged for recovery of the costs of a new IGCC plant are subject to FERC jurisdiction and meet the requirements for market-based rates, then the rates can include the elements specified in the model mechanism.

The FERC allows market-based rates for sales for resale if there are showings that: the transactions have no potential abuse of self-dealing or reciprocal dealing; and the seller lacks market power or has adequately mitigated its market power. Id.; AEP Power Marketing, Inc., 97 FERC par.61,219 at 61,969 (2001).

In an arms-length transaction involving a non-affiliated seller and buyer (e.g., sales from an independent-power-producer-owned IGCC plant to a distribution utility), there seems to be no potential abuse since the buyer has no economic incentive to favor anyone except the least-cost supplier. In that case, the FERC evaluates whether the seller has market power in order to ensure that the seller cannot limit supply or transmission options and thereby raise the price. Boston Edison, 55 FERC at 62,168. A seller has market power when, for example, the seller can significantly influence price in the market by restricting supply or denying access to alternative sellers. Id. at 62,167 n.54.

When a transaction involves a seller and a buyer that are affiliates (e.g., sales from an IGCC plant owned by an affiliate of a distribution utility to that utility), there may be potential abuse. If the seller is not regulated and the buyer is, the seller can charge excessive prices to the affiliated buyer and retain the profit. If the seller is regulated and the buyer is not, the seller can charge preferentially low prices to the affiliated buyer and disadvantage the buyer's competitors. Id. at 62,168 n. 56. In a case where there is potential abuse, the company must demonstrate a lack of abuse, regardless of whether the company has market power. Id. at 62,169 n. 67. The company may make this first demonstration by showing, for example, direct competition between its affiliate and unaffiliated, alternative suppliers and justifying the choice of the affiliate. Id. at 62,168. Alternatively, the company may provide benchmark evidence on the prices and terms and conditions for similar services in contemporaneous transactions in the relevant market involving non-affiliated buyers or non-affiliated sellers. [145] Id. at 62,168-69.

[145] If benchmark prices are considered, it is unclear, as noted above, how the FERC will treat additional IGCC plant costs attributable to deployment of new, complicated technology or installation of equipment that goes beyond current environmental requirements.

The FERC will conduct its own evaluation of potential abuse in an affiliate transaction even if the state involved also will review the transaction. Id. at 62,170.

Concerning the market-based-rate requirement that a seller lack market power or adequately mitigate its market power, this requirement is met by demonstrating that the company and its affiliates: are not dominant in electricity sales in the relevant market; do not own or control transmission facilities through which the buyer could reach alternative suppliers (or if they do own or control such facilities, they have mitigated their ability to block access), and cannot erect or control any other barriers to market entry. Id. at 62,176. Generally, the absence or mitigation of market power through ownership or control of transmission facilities is demonstrated if the company and its affiliates have an approved open access transmission tariff. AEP Power Marketing, 97 FERC at 61,969. However, with regard to the question of dominance of the company and its affiliates in electricity sales, the FERC is still in the process of refining the demonstration that is required.

As the FERC recently explained, the demonstration of lack of generation market power has generally been focused on whether the company's (and its affiliates') share of installed and committed generation in a particular market exceeded 20 percent. Id. However, in light of recent changes in the electricity market, the FERC is conducting a generic review of the market power issue. Pending that generic review, the FERC presented a modification of the generation-market-power demonstration using a new test (referred to as the "Supply Margin Assessment screen"). Id.

Under the Supply Margin Assessment screen, the relevant geographic market for analysis is determined, considering constraints on transmission. A company fails the Supply Margin Assessment screen if the company's generation capacity exceeds the amount of the relevant market's surplus capacity above peak demand, regardless of whether the company's generation capacity exceeds 20 percent of the market's total generation capacity. Under this approach, a company with capacity exceeding the market supply margin is regarded as a "must-run supplier needed to meet peak load" and having the potential "to successfully withhold supplied in the market in order to raise prices." Id. at 61,970. The Supply Margin Assessment screen does not apply to sales into a transmission system under an independent system operator (ISO) or regional transmission organization (RTO). If a company fails the Supply Margin Assessment screen, certain requirements are imposed to mitigate market power. For example, the FERC may require the company and its affiliates to offer uncommitted generation capacity for spot market sales in the relevant market and to price that capacity using cost-based rates that divide the benefits of the transaction between the buyer and the seller. Id. at 61,971-72; see id. at 61,972-73 (describing additional requirements for mitigating market power).[146]

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[146] The application and implications of FERC market-based-rate review, which are summarily discussed in this draft

6.4. State legislative changes necessary for use of model state mechanism.

The model state mechanism for review, approval, and recovery of IGCC plant costs is designed to, inter alia, minimize, to the extent consistent with the requirements of the 3Party Covenant, the amount and complexity of state legislative changes necessary for use of the model mechanism. Not surprisingly, the legislative changes that may be necessary will vary from state to state. Below is discussed the legislative changes that may be needed in the four sample states: Indiana, Kentucky, Ohio, and Texas.

The least amount of changes seems to be necessary in Indiana. As discussed above, Indiana already has in place a series of provisions authorizing, for application to "clean coal technology," the key elements in the model state mechanism. In fact, the model mechanism was, to a large extent, developed based on a review of Indiana law. The key elements of the model mechanism include: up-front "due diligence" review of, and issuance of a certificate of public convenience and necessity for, the IGCC project by the state utility regulatory commission; ongoing prudence review of project preconstruction and construction costs by the commission from commencement of construction through plant start-up and assurance of future pass-through of approved capital investments and associated cost of capital; ongoing pass-through, during construction, of cost of capital for approved capital investments; ongoing prudence review of project operating costs by the commission; and ongoing pass-through of depreciation and amortization of approved capital investments, associated cost of capital, and operating costs. While it appears that the operative terms for some of these provisions, "air pollution control property" and "clean coal technology," can reasonably be interpreted to cover an entire IGCC plant, it may be desirable for the state PUC (with support from the state attorney general and possibly the state legislature) to adopt expressly that interpretation.

More legislative changes may be necessary in order to adopt the model state mechanism in Kentucky. As discussed above, Kentucky has in place less elaborate procedures than Indiana, but provides for ongoing review, approval, and recovery of capital investment, associated cost of capital, and operating costs for "complying" with environmental requirements. While the operative term, "complying" with environmental requirements, may reasonably be interpreted to cover an entire IGCC plant, it may be desirable for the state legislature to adopt expressly that interpretation. In addition, it may be desirable for more detailed provisions to be adopted concerning: up-front "due diligence" review of, and issuance of a certificate of public convenience and necessity; ongoing prudence review of project preconstruction and construction costs and operating costs; and, in particular, assurance of pass-through of approved depreciation and amortization of capital investments and associated cost of capital (including cases of uncompleted plant) and of approved operating costs. These types of legislative changes seem to

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report, warrant further research and consideration for the final report.

be consistent with Kentucky's express policy to "foster and encourage use of Kentucky coal by electric utilities." KC 278.020(1).

More extensive legislative changes may be necessary in order to adopt the model state mechanism in Ohio and Texas. As discussed above, one result of deregulation legislation in those states is generally to require that: investors bear the full risk of new electricity generating plant; and the costs of such plant be recovered through rates determined by the electricity market, rather than through cost-of-service rates based on review and approval by the state utility regulatory commission. In order to provide the shift of risk to ratepayers and the assured revenue stream that are necessary to implement the 3Party Covenant, legislation creating an exception for IGCC plant under the 3Party Covenant from the general deregulatory regime in Ohio and Texas may be necessary. In particular, legislation may be needed to allow inclusion in a nonbypassable wires charge -- analogous to the nonbypassable wires charges for stranded costs and for certain public benefit programs -- of the costs of a limited number of IGCC projects approved by the state PUC for coverage under the 3Party Covenant, including the federal loan guarantee. It also may be necessary to set forth reasonably detailed provisions for: up-front "due diligence" review of, and issuance of a certificate of public convenience and necessity by the state PUC; ongoing prudence review of project preconstruction and construction costs and operating costs by the commission; and assurance of pass-through of approved depreciation and amortization of capital investments and associated cost of capital (including cases of uncompleted plant) and of approved operating costs.

In addition, in Ohio (but not in Indiana, Kentucky, and the ERCOT region in Texas), in order for the state PUC to retain jurisdiction over the rates through which the IGCC project costs are recovered, it may be necessary for the state legislature to make it clear that a utility distribution company may own or lease a new IGCC plant approved by the state PUC for coverage under the 3Party Covenant.[147] Under the more traditional approach to utility regulation in Indiana and Kentucky, of course, an electric utility may own or lease a new IGCC plant and sell the output to retail customers. As discussed above, it seems unclear whether Ohio statute and Texas statute bar utility distribution companies from owning or leasing electricity generating facilities. If an IGCC project is instead owned or leased by an affiliate of the utility distribution company, then the provision of capacity and electricity to customers of the utility distribution company seems to involve a sale for resale, which, in Ohio but not in the ERCOT region in Texas, appears to invoke FERC, rather than state, jurisdiction, over the rates for IGCC plant.

The types of legislative changes discussed above for Ohio are arguably consistent with Ohio's policy of "[e]ncouraging innovation...for cost-effective supply-...side retail electric service"

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[147] The sale of capacity and electricity from an IGCC project owned and operated by an independent power producer to a utility distribution company seems to be a sale for resale. In Ohio, Indiana, Kentucky, and outside the ERCOT region in Texas, it appears that this will invoke FERC jurisdiction.

(ORC 4928.02(D). However, in considering these types of changes, Ohio and Texas will, of course, consider other relevant state policies, such as those concerning promotion of competition in Ohio and Texas and encouragement of new gas-fired generation in Texas.

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