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The Challenge of Carbon Sequestration for the Utility Sector

Comments

from the American Public Power Association to

The National Commission on Energy Policy

In response to Nov. 9, 2005 meeting

and

Papers submitted to NCEP website

Submitted by

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The Challenge of Carbon Sequestration for the Utility Sector

Who we are

The American Public Power Association (APPA) is the service organization for the nation's more than 2,000 community- and state-owned electric utilities. It represents public power's interests in Washington, D.C., and provides an array of services to help its members with managerial and operational issues. We represent approximately 16 percent of the electric utility sector.

After decades of promise, Integrated Gasification/Combined Cycle (IGCC) appears to be entering a phase of near-term commercialization. The last 12 months have witnessed unprecedented interest in IGCC technology – numerous projects have been proposed, involving at least six major operating utilities. This commitment is important - as the National Commission on Energy Policy (NCEP) noted, IGCC technology is timely given the energy security needs of the U.S.

Given these announcements and ensuing interest, a speaker at the Nov. 9th workshop commented “the utility sector is halfway there to carbon sequestration at an IGCC plant”. In the context of the press announcements and floor debate (colloquies) on the recent Energy bill, it might be easy to jump to that conclusion. However, it is important to recognize the uncertainties that persist with not only IGCC but also the second step and most significant step – sequestration of the captured carbon. As summarized in these comments, numerous challenges remain that could prevent broad deployment of IGCC and sequestration for the U.S. power generation sector. Notwithstanding the success of Cinergy's Wabash River and Tampa Electric's Polk projects, the remaining challenges are formidable. The recent National Energy Policy Act of 2005, by directing significant funds to IGCC commercialization and generalization, testifies the recognition by Congress and the Department of Energy (DOE) of the uncertainties as well as the promise of IGCC. **APPA supports this effort at the DOE to look into IGCC and other technologies to reduce, minimize or prevent GHGs from the utility sector over the decades to come.**

Background on APPA and the climate issue

APPA is also a signatory, along with other power sector trade associations, to the President's Climate VISION Memorandum of Understanding (MOU) with the Department of Energy (DOE). The overall goal of this MOU is to support the President in his efforts to reduce the GHG emissions intensity of the U.S. economy by 18 percent by the end of 2012. The partnership between the power sector and DOE intends to facilitate action by the power sector trade associations and their members to reduce collectively the power sector's GHG emission intensity by an equivalent of 3 to 5 percent below 2000-2002 baseline levels.

APPA's TREE POWER™ program and carbon sequestration

APPA has a program, founded in 1991, that currently has 248 members to plant trees for both carbon sequestration and helping our members' customers to save energy (from shade management and wind breaks) and aesthetic enhancement of neighborhoods. There are many environmental and economic benefits from tree planting. Of the 248 member utilities which participate, seventy-two utilities (or nearly 30%) have earned the Golden Tree Award for planting at least one tree for every customer they serve. TREE POWER™ utilities now serve 19.5 million customers—50% of public power's total customers. **Golden Tree Award-winning utilities alone have planted over 1,436,042 trees totaling or representing customer/meters.**

TREE POWER™ has earned a number of awards including:

- National Arbor Day Foundation: Arbor Day Project Award 2005;
- Trees Forever: President's Award 2002;
- National Awards Council for Environmental Sustainability; Certificate of Environmental Achievement, Renew America Environmental Success Index 1992, 1995, 1996;
- Associations Advance America: Award of Excellence 1995;

Why APPA has submitted these comments

The previously cited quote – that the utility sector is “halfway there to carbon sequestration” – was offered in a presentation to the Nov. 9th meeting of the NCEP. APPA shares this speaker's enthusiasm for IGCC, and the “stepping stone” that it provides for possible carbon sequestration. However, APPA submits that additional research, development and demonstration are required before carbon sequestration can be seriously considered. Further, the uncertainties and protracted time scales of sequestration events merit a stepwise, methodical approach to assure any concerns for CO₂ emissions are not exchanged for a different environmental issue.

IGCC: The *Promise* and Challenge

APPA views the performance, cost, reliability, and technology generalization issues of IGCC as follows:

- *Performance highlights of IGCC*

IGCC offers several performance advantages, in terms of both control of emissions and carbon use, which can be attributed to the integrated, “multi-pollutant” nature of the concept. Specifically:

- 1 extremely high removal of “criteria pollutants”: for SO₂ to 99%, for NO_x control to < 0.05 lbs/MBtu, and for particulate matter to less than 0.010 lbs/MBtu.
- 2 the use of “combined” thermodynamic cycles, providing a stepping-stone to high thermal efficiency, at present to 38-40%, with the potential to exceed 50% if advanced turbine technology evolves.
- 3 a low volume of combustion products – about 1/100th compared to conventional flue gas volume - while featuring high CO₂ concentration, enabling processing of CO₂.

Within the context of these advantages, the following challenges must be recognized:

- *Cost*

IGCC technology represents an increase in generating cost over conventional coal of 15-20%, under the conditions that CO₂ removal is not required.¹ If CO₂ removal is required,

¹ Basis: Cost of Electricity (COE), accounting for capital recovery and operations. See

the premium for IGCC over an advanced pulverized coal-fired plant decreases. Another way to view this is in terms of the incremental cost of CO₂ capture and sequestration - representing a 70% premium for advanced pulverized coal plants, but a 25% premium for an IGCC plant. Given current anticipated increases in the cost of fuels and generation, this possible additional cost is not insignificant.

The cost premium for IGCC is fundamental and pervasive to the technology – and as EPRI argues through the “Coal fleet for Tomorrow” initiative, incentives are needed for IGCC.

- ***Generalization—is IGCC suitable for all coal types?***

The coal reserves of the U.S. – providing 250 years worth of domestic energy supply - are not a monolithic in nature. These reserves exhibit a variety of physical and compositional characteristics, and accordingly are characterized as bituminous, subbituminous, or lignite. An IGCC design acceptable for broad deployment must be applicable to most coal types. The current versions of IGCC demonstrated are not suitable for most coal types.

Successful deployment requires demonstrating a portfolio of design options. Significantly, EPRI has cited that IGCC may be best suited for eastern bituminous coals, with perhaps supercritical PC most appropriate for subbituminous or lignite coals.² EPRI further notes that a design database is required to generalize the matrix of design concepts (three types of entrained flow gasifiers, and several transport-gasifiers) for broad deployment. Combined with variances in coal type, EPRI proposes that eight state-of-art designs be addressed in the “Coal fleet for Tomorrow” initiative. Success with one concept - albeit impressive - is only the first of several steps.

It is extremely important for APPA to stress that fuel availability and transportation of the fuel is not as predictable under current market, labor, and rail conditions. While these are not immediately obvious to the discussion of IGCC and carbon sequestration, APPA is reminded that solutions for carbon sequestration should consider the complexities resulting from changing fuels, transportation, captive rail and other issues that are “real world problems”. In the last few years more utilities have fewer fuel choices to make between coal types or ranks due to transportation, labor, force majeure in contracts, and other issues. These issues are ancillary to the discussion of carbon sequestration but they are very important in the context of fuel choices. Fuel choices are fundamental to the type of coal plant that is built. Because of these issues, more utilities are concerned about making decisions that allow for the widest diversity of fuels to be used.

- ***Reliability***

IGCC is necessarily more complex than conventional pulverized coal – a consequence of the demands imposed on the technology. It is unfair to judge present-day IGCC based on the reliability provided by the two present U.S. applications – but this reduced reliability cannot be ignored. In this manner, it is notable that EPRI cites the most reliable unit to date as Cinergy’s Wabash River facility, with a 79% reliability history.

“Coal-Based Generation: At the Crossroads”, EPRI Journal, Summer 2005.

² Ibid, page 11.

As further testimony to the evolving nature of IGCC, the National Energy Policy Act of 2005, recently passed by the U.S. Congress on July 29, 2005, contains the following incentives for gasification-based technologies:³

- 1 \$1.8 billion extension of the Clean Coal Power Initiative, with a minimum of 70% of funds directed to gasification-based technologies,
- 2 a Clean Coal Power Projects “Title” that earmarks a number of specific projects for loans and loan guarantees,
- 3 up to \$800M in investment tax credits for IGCC projects
- 4 an additional incentive for an innovative technologies program, authorized to provide loan guarantees for gasification-based projects,

Notably, several prominent IGCC projects will receive DOE subsidy, such as the Excelsior Energy/Conoco Phillips design study for the proposed Mesaba Project, and the Orlando Utilities Commission (OUC), an APPA member, and Southern Energy IGCC unit for the Stanton Energy Center.⁴ A further example of incentives is the offer for tax credits for in-state IGCC projects by the state of Indiana, for projects that utilize Indiana coal. APPA supports the \$235 million in cost sharing for DOE research at the Stanton plant as well at other IGCC plants.

Sequestration: The Finishing Step

This is the hardest part. The second step in the process to remove CO₂ as a concern – sequestration likely faces greater uncertainty than the task of capturing CO₂. **The options to sequester CO₂ are (a) direct, requiring the injection of CO₂ where it presently either doesn’t exist or exists in low concentration, or (b) indirect, encouraging the uptake or absorption into existing earth resources. Both are promising but highly uncertain.**

Direct Injection

The direct injection into subterranean cavities has received considerable attention. These include oil and gas reservoirs, unminable coal seams, and deep saline reservoirs. Many of these cavities contain porous media and are capped by a separate, non-porous and impermeable media.

Oil and Gas Reservoirs. Production of oil and gas can be increased by forcing CO₂ to displace the hydrocarbon fuel – a recent press release certifies the promise.⁵ CO₂ removal from flue gas in this manner represents a value-added product. Several key questions are unanswered – will the higher pressure required for displacing hydrocarbons alter the physical structure of the porous media, preventing further CO₂ influx after an initial threshold? Also, to date this application (referred to as Enhanced Oil Recovery, or EOR) has been designed to minimize CO₂ consumption, and to retain the CO₂ within the reservoir for at most several years. In contrast, EOR concepts intended for sequestration will maximize the consumption of CO₂, and retain it for several hundred years. These application conditions are uncertain and not addressed by present experience. (Even if the technical questions are resolved, another question to resolve is who is credited for this carbon sequestration—exclusively the oil and gas companies who own these production

³ The National Energy Policy Act of 2005 summary reflects excerpts from the Gasification Technologies Council, available at www.gasification.org, visited August 1, 2005.

⁴ Federal funding for both projects is summarized at www.gasification.org, under “News” for 2004.

⁵ “DOE CO₂ Sequestration Project Seen As a Success”, Energy Daily, November 21, 2005.

facilities or the owners of the CO₂ to be injected. This is not an insurmountable issue but needs considerable thought).

Coal Bed Methane. CO₂ can be used to displace the methane that is adsorbed onto the surface of the coal (instead of depressurizing the bed and removing water), and thus represents a value-added byproduct. Significant deposits of coal exist that for various reasons – usually the depth below the earth’s surface – are unusable. Similar to geologic formations for oil and gas reserves, it is not known if introducing CO₂ at high pressure to displace methane will fracture the coal or otherwise change the physical structure in a way to inhibit further CO₂ injection, or allow leaks to the surface. Long-term demonstrations are required.

Underground Saline Formations. Sequestration of CO₂ in deep saline formations does not produce value-added by-products, but can present significant advantages. These include (a) significant potential global carbon storage capacity, and (b) close access to many power stations. The existing (limited) experience appears quite impressive. Since 1996, a Norwegian oil company (Statoil) has been injecting approximately one million tons per year of recovered CO₂ (equivalent to a 150 MW power plant) into the Utsira Sand saline formation under the North Sea. However, the same issue – the potential for CO₂ to escape from the target formations, migrate to the surface, or contaminate water supplies – is uncertain. While APPA is not a part of the oil and gas sector it notes that one of the reasons that the CO₂ sequestration by a Norwegian company might be more cost effective is because of a national or EU CO₂ tax that the company is seeking to avoid or minimize. Reminding the reader of a considerable tax does not diminish the benefits of CO₂ sequestration but it is offered to illustrate the complexity of the decision making involved and the economics behind the decision to inject CO₂ into a saline formation. It is not clear if, absent the tax, if the carbon sequestration into that formation would be economically viable even if it is technologically viable.

Ocean Sequestration

The solubility of CO₂ in water presents the opportunity to absorb significant CO₂ through natural processes. DOE estimates that 80-90% of CO₂ that contacts ocean water will eventually absorb, but at a rate so slow a CO₂ peak will linger for several hundred years. **Without success in increasing the rate of absorption – which DOE is actively engaged in – ocean sequestration may not be a viable means to secure CO₂.**

Although technology exists to directly inject CO₂ into the ocean, the biological and chemical impacts of the CO₂ plume are unknown. A complementary method involves adding combinations of micronutrients and macronutrients to those specific ocean surface waters that are deficient in such nutrients, increasing the ocean’s absorptive capacity. Specifically, fertilizing the ocean by adding iron chelates to high nutrient, low chlorophyll regions is identified as a productive concept. The objective is to stimulate the growth of phytoplankton, and thus consume greater amounts of CO₂. This method of artificially stimulating plankton blooms, in order to increase the natural “pump” by which CO₂ is removed, appears promising but again, highly uncertain.

The extent to which CO₂ from this increased biological activity is sequestered is unknown at this point, and would require additional research. APPA urges DOE to explore these and other options to safely accelerate the rate by which the oceans absorb CO₂, enabling direct injection into the deep ocean. There are valid reasons for concern - small changes in biogeochemical cycles that appear subtle can have large consequences, many of which are secondary and difficult to predict. Of particular concern to some is the potential effect of CO₂ on the acidity of ocean water, as changes in ocean pH have been noted for years and concerned biologists. **APPA believes these concepts should be approached with**

extreme caution, with concern for unknown biological consequences such as uncontrolled toxic blooms or apoxia in our coastal waterbodies and oceans.

Terrestrial Sequestration

Enhancing the natural processes that remove CO₂ from the atmosphere could be the most cost-effective means of reducing CO₂, utilizing present efforts to increase forestation (and avoid de-forestation). Both protecting the viability of existing carbon sinks, and manipulating ecosystems to increase carbon removal are possible. Forestlands, agricultural lands, biomass croplands, deserts, and wetlands are all candidates. Of course, significant R&D is required particularly for the latter to increase carbon removal without introducing distortions to present ecosystems. (APPA's TREE POWER™ program has already been described).

General Energy and Environmental Concerns

While some sequestration approaches look promising, the industry has an obligation to consider the long-term environmental consequences (beyond climate) and the safety of CO₂ storage into land or ocean topography. These efforts will focus on reservoirs for oil and gas deposits, saline formations, underground caves, and the ocean. Determining that CO₂ will not escape from formations and either migrate to the earth's surface or contaminate drinking water supplies is a key aspect of sequestration research. As a society, we have learned from experience with MBTE – that unintended consequences from underground storage can exchange one environmental problem for another. It would be terrible to exchange one problem for another—perhaps even a larger problem. Equally important, the injection of CO₂ into marine or ocean systems should be approached with great caution so as not to distort or stress ocean composition and pH, temperatures, and thus marine habitat.

Related to environmental concerns, APPA urges avoiding technological concepts that significantly increase the use of energy – further compounding the challenges. Any concept that significantly – meaning more than 15-20% – increases carbon consumption for the purpose of CO₂ mitigation will challenge the premise of identifying a “carbon neutral” solution. While some of the technologies described in the materials on the NCEP website are intriguing, APPA did not see any summary or details on the energy used to produce these results. In some instances there might not be GHG reductions after considering the additional energy needs for the process.

Advanced Concepts

Demonstration experience may show the only way to economically and effectively remove CO₂ as a possible concern for our society is to develop advanced, cutting-edge technologies. Successful sequestration of CO₂ may have to await such developments.

One approach is to reduce the cost and energy required to chemically and/or biologically convert CO₂ into commercial products that are (a) inert and long-lived, or (b) stable solid compounds. APPA is aware of two promising chemical pathways: magnesium carbonate and CO₂ clathrate, the latter an ice-like material. Both provide quantum increases in volume density compared to gaseous CO₂. APPA is not qualified to assess the viability of chemically transforming the CO₂ into inert compounds or what happens to these compounds when produced.

Concerning biological systems, incremental enhancements to the carbon uptake of photosynthetic systems could have a significant positive effect. Also, harnessing naturally occurring, non-photosynthetic microbiological processes capable of converting CO₂ into useful forms, such as methane and acetate, could turn the problem of CO₂ capture into an economic opportunity – and is worthy of intense research. It should be noted that

biological means of processing CO₂ do not necessarily require highly pure CO₂, and thus may not incur the same costs for separation, capture, and compression of a relatively pure CO₂ gas.

Final Perspective: The Laws of Unintended Consequences

These comments are intended to convey the message that APPA is optimistic about the evolution and deployment of IGCC technology for power generation. Further, APPA supports long-term research to provide an effective means to render CO₂ harmless. However, in the near-term, several concerns exist regarding technology availability and possible impacts, which are summarized as follows:

- 1 Injection of CO₂ into oceans could change water temperature, composition and acidity, and thus impact biological activities and aquatic species. Any detriment may not be evident for decades, and research should quantify the possible outcomes.
- 2 Lessons learned from 1950-1970s with leaking underground storage tanks have taught us to be cautious about injecting into the earth any substances that might be prone to migration or seepage. Despite the limited and initial success with CO₂ injection for Enhanced Oil Recovery, the reality is that sequestration applications will require more challenging CO₂ delivery and storage pressures, and much longer retention times. Consequently, a significant component of DOE research is directed to quantifying the migration rate of CO₂ within subterranean porous media, if sustained injection alters the physical properties of the media, and if migration of CO₂ can be capped.
- 3 Accountability and ownership of the sequestration or credits resulting from credits- - it is not clear where does the ultimate responsibility or ownership/management chain lie with sequestered material? Haven't we learned the hard way from the Superfund program that ownership and management issues are complex and require considerable thought before the product or compound changes hands? There are many chain of ownership questions that emerge once the technology and feasibility issues have been resolved. For example, do CO₂ sequestration "rights" parallel mineral rights, and will the mine or reservoir owner be responsible for the ultimate fate of sequestered materials? What will utilities do if they have no "mine-mouth" operations or close proximity to land or ocean geologic formations suitable for sequestration? The papers and presentations did not begin to address these complexities which are very real.

Conclusion

APPA believes that IGCC, along with other forms of advanced generation, should be encouraged to meet our nation's energy needs. However, APPA believes it is wise to point out that IGCC, while beneficial for other reasons, may not yet prove as promising for CO₂ sequestration as might be currently assumed or believed based upon the NCEP materials and recent presentation. APPA does not discourage the building of IGCC plants, where they make sense for that utility. However, APPA does not believe that public officials, regulators, rate payers or consumers should have the impression that carbon sequestration is viable now at existing or newly constructed IGCC plants, or that we are "halfway there to carbon sequestration". APPA believes strongly in the DOE and NETL programs designed to research appropriate technological breakthroughs for carbon sequestration, mitigation or prevention.

APPA has attached two EPRI papers which we wish that NCEP would also post to its website.

Thank you for allowing us to submit these comments.

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Attachments

1. [EPRI Journal Article on Coal and IGCC](#)
2. Coalfleet Incentives

**Financial Incentives for Deployment of IGCC:
A CoalFleet Working Paper**

**Prepared for the
Senate Committee on Energy & Natural Resources
Bipartisan Coal Conference
March 10, 2005
Washington, DC**

About This Paper

This working paper is an evolving document that summarizes the key insights from CoalFleet incentives analyses. The underlying philosophy of the analyses is to illustrate how a range of companies might value Federal incentives.

This version (March 10, 2005) of the paper, which focuses on IGCC deployment incentives, is undergoing internal and external review. Specifically:

- We continue to review financial analysis methods with a broad range of companies (investor-owned utilities, independent power producers, and public power entities) to ensure that our basic approaches are consistent with how they would evaluate IGCC versus a more conventional pulverized coal plant.
- We have initiated a coordinated effort with DOE's Office of Policy to examine incentive value using their financial models and to estimate the cost of incentives to the government.
- We have initiated an outreach effort to review and discuss our initial results with other research groups.

Next steps include examining additional incentives and examining similar issues for other advanced coal technologies.

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CoalFleet for Tomorrow is an industry collaborative formed to accelerate the deployment and commercialization of clean, efficient advanced coal power systems, thereby preserving this abundant fuel option as a vital component of our nation's and the world's energy mix. The CoalFleet initiative addresses the technical, economic, and institutional challenges to making advanced coal power plants a prudent investment option in both the short and long term, while taking into account the potential for future CO₂ emission regulations.

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, non-profit center for public interest energy and environmental research. EPRI brings together member organizations, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of power generation, delivery and use, including health, safety and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents over 10% of EPRI's total R&D program.

Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper

Executive Summary

Integrated gasification combined cycle (IGCC) is an electric generating technology that gasifies coal, uses the gas to power a combustion turbine to generate electricity, and uses the turbine's waste heat to generate additional power. IGCC promises higher thermal efficiency and lower air pollution emissions than conventional coal-fired power plants (PC), as well as the potential for being able to produce a concentrated waste stream of CO₂ that could be captured and sequestered in geologic formations. IGCC has been used in a number of U.S. demonstration facilities but as yet has not been commercially deployed in the United States because of its higher capital cost and technology risk.

This paper presents EPRI's analysis of the effectiveness of eight alternative Federal financial incentives that have been proposed to mitigate IGCC's higher costs and risks. The intent of these incentives is to lessen the cost differential between IGCC and conventional coal technologies so that an initial set of IGCC plants will be deployed, allowing future experience-based reductions in cost and improvements in performance that could make IGCC commercially viable. The incentives analyzed include: loan guarantees, direct Federal loans, Federal cost sharing grants, investment tax credits, production tax credits, tax-exempt financing, accelerated depreciation, and Federal availability insurance. The analysis looks at the usefulness of each incentive for three types of project owners: regulated investor-owned utilities (IOUs), independent power producers with a power purchase agreement (IPPs), and public power (including cooperative, Federal, municipal, and state entities).

The analysis compares the cost of an IGCC plant with the cost of a conventional supercritical PC plant in terms of cost of electricity (COE) – that is, the levelized cost of electricity produced from a generating unit over a 30-year period. COE is a useful method for comparing the costs of competing coal technologies, both for asset owners and utility customers. The analysis indicates that, without incentives, COE for IGCC units significantly exceeds COE for conventional coal units. This “COE gap” is in the 17-19% range. About half the COE gap is attributable to higher capital costs. The other half is attributable to technology risk – the risk that the unit will not attain design levels of performance, as shown in Table A.

Table A. COE Gap Without Incentives (\$/MWh)

COE Gap (IGCC – PC)	IOU	IPP	Public/Coop
Capital Cost Gap (without technology risk)	\$ 3.90	\$ 4.43	\$ 2.70
Technology Risk COE Gap	\$ 4.00	\$ 3.34	\$ 2.71
Total COE Gap	\$ 7.90	\$ 7.77	\$ 5.41

The incentives examined (shown in Table B) have varying value to different project owners. For example, while tax incentives may have significant value to profitable IOUs and IPPs, they have

no value (unless they are tradable) to public entities. Given our assumptions, none of the incentives studied are individually sufficient to bridge the COE gap faced by the various prospective project owners.

Table B. Value of Base Case Incentives Compared With COE Gap (\$/MWh)

	IOU	IPP	Public/Coop
Loan Guarantee with No Fee	\$ 1.08	\$ 1.80	\$ 0
Direct Loan	\$ 3.24	\$ 6.76	\$ 0
Cost Sharing Grant (10% without repayment)	\$ 2.08	\$ 2.17	\$ 1.54
Investment Tax Credit (ITC) (10%)	\$ 2.29	\$ 2.37	\$ 0
Production Tax Credit	\$ 4.24	\$ 4.23	\$ 0
Tax Exempt Financing	\$ 2.97	\$ 4.85	\$ 0
Accelerated Depreciation	\$ 3.14	\$ 3.33	\$ 0
Availability Insurance (at 78% actual availability)	\$ 0.90	\$ 1.02	\$ 0.82
<i>IGCC – PC COE Gap</i>	<i>\$ 7.90</i>	<i>\$ 7.77</i>	<i>\$ 5.41</i>

While none of the base case incentives are sufficient to fill the COE gap, combining several incentives or scaling them up can reduce or eliminate this gap. Table C borrows from existing proposals and from legislation for other energy sources to provide several examples of how incentives can be tailored to do so: (1) combining a scaled-up, 20% investment tax credit (ITC) with accelerated depreciation, (2) an enhanced production tax credit (PTC) equal to the current wind PTC, and (3) combining a 30% Federal cost-sharing (with no repayment required) and availability insurance. While different project owners are likely to value the incentive packages somewhat differently, these estimates provide useful insight into how incentives could be tailored to bridge the COE gap for all three types of companies.

Table C. Value of Tailored Incentives Compared With COE Gap (\$/MWh)

	IOU	IPP	Public/Coop
20% ITC + Accelerated Depreciation	\$ 7.72	\$ 7.06	\$ 0
Wind Energy PTC (\$18/MWh)	\$ 8.48	\$ 8.46	\$ 0
Cost Share (30% without repayment) + Availability Insurance	\$ 6.25	\$ 6.51	\$ 5.44
<i>IGCC – PC COE Gap</i>	<i>\$ 7.90</i>	<i>\$ 7.77</i>	<i>\$ 5.41</i>

This preliminary analysis provides a clearer view of the value of possible Federal incentives for encouraging initial deployment of IGCC for companies considering new coal-based generation options. It does not address refueling of existing combined cycle units with syngas, the economics of potential non-electric products of gasification, or the use of other gasifier feedstocks such as petroleum coke and biomass. Also, at this time we do not address the cost of alternative incentives to the Federal government.

Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper

I. INTRODUCTION

Gasifying coal to produce electricity is an alternative to the traditional method of directly burning coal in pulverized coal (PC) facilities. This process is referred to as Integrated Gasification Combined Cycle (IGCC). In coal gasification, a gasifier reacts the coal with steam and controlled amounts of air or oxygen under high temperatures and pressures. The heat and pressure break apart the chemical bonds in the coal's molecular structure, setting into motion chemical reactions with the steam and oxygen to form a gaseous mixture, called a synthesis gas (or syngas), made up primarily of carbon monoxide and hydrogen. The syngas is then combusted in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators (hence the term "combined cycle").¹ IGCC provides higher thermal efficiency than current PC plants, lower emissions, and the potential for carbon capture and sequestration. (See discussion below in part II.)

There are four coal-fired IGCC facilities in operation today.² Two of these are demonstration facilities located in the United States – the Tampa Electric IGCC facility located in Florida (GE/ChevronTexaco gasifier) and the Wabash River Coal Gasification Repowering Project located in Indiana (E-Gas™/ConocoPhillips gasifier). The other two are located in Europe.³

Although gasifying coal is a commercially proven process and is used throughout the world in developing chemicals, fuels, and other by-products, the integration of coal gasification with a combined cycle power block to produce electricity is a relatively new technique and involves an operational complexity beyond that experienced with PC plants. And while operational at near commercial-scale (250 to 300 MW in size), each of the existing IGCC units has encountered various technical and operational impediments relating to the reliability of the system. For IGCC to be cost competitive in the retail electricity market, IGCC plants will likely need to be available for power production in the range of 80-90% of the hours in a year. However, these existing IGCC demonstration projects have failed to consistently achieve this target without a spare gasifier. While use of a spare gasifier significantly improves the availability of an IGCC plant, the use of a spare also increases the capital cost of the plant. Another limitation is that current gasifier technology is only proven to be cost effective with bituminous coals.⁴

II. POTENTIAL BENEFITS OF IGCC TECHNOLOGY

The IGCC process increases the efficiency of the overall system by using the waste heat from the combustion turbine to produce steam to drive the steam turbine. Existing commercially available IGCC systems are expected to achieve a thermal efficiency of approximately 39-41%.⁵ In comparison, the existing fleet of pulverized coal facilities in operation in the U.S. today is generating electricity with an average thermal efficiency of about 33%.⁶ With further advances in gas turbine technologies, it is believed that IGCC systems are capable of reaching efficiencies

of 45-50%. Hence, IGCC provides a new, potentially competitive coal-fired electricity generation option. More importantly, deployment of IGCC units would provide significant energy security, fuel diversity, and environmental benefits.

Energy Security and Fuel Diversity. Coal is the nation's most abundant domestic energy resource but low natural gas prices and uncertainty as to future environmental limitations on coal use have constrained construction of new coal-fired generation units. Since 1990, only about 15 GW of new coal-fired capacity has been completed in the United States. By contrast, about 200 GW of new natural gas capacity has been placed in service in the same period. Because of IGCC's capability to reduce conventional emissions and its carbon capture potential (see below), widespread deployment of IGCC units offers the prospect of retaining or even increasing coal's place in the power generation market. In some cases, efficient coal gasification equipment could be used to repower existing gas combined cycle units, directly displacing natural gas use. Increased use of coal could take some of the pressure off of natural gas prices, which have more than doubled since early 2000 and are forecasted to remain relatively high.

Air Quality Benefits. If widely deployed, IGCC promises substantial air quality and public health benefits. Because pollutants can be separated from the gaseous stream before combustion of the syngas, IGCC systems can achieve very low emissions of conventional air pollutants, such as sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter, and mercury. A state-of-the-art IGCC unit can remove as much as 99% of sulfur and 90-95% of mercury.⁷

Potential Climate Change Benefits. An important feature of the IGCC system is that carbon monoxide in the synthesis gas can be reacted with steam to make hydrogen and carbon dioxide (CO₂). This creates the potential to separate a relatively pure stream of CO₂, which can feasibly be "sequestered" in geologic formations, thus avoiding its emission into the atmosphere.⁸ IGCC's carbon capture capability provides a useful hedge against regulatory uncertainty, should policy-makers decide to impose binding limitations on CO₂ emissions in the future.

Table I compares the performance of (i) new conventional PC units (based on the design parameters of new super-critical units currently in the permitting stage) compared with the expected performance of (ii) current IGCC units (those likely to be deployed were Congress to adopt a financial incentives program), (iii) near-future IGCC technology (units built after the initial units were deployed), and (iv) 2020 IGCC (the performance targets under the DOE/CURC/EPRI roadmap [<http://www.coal.org/content/roadmap.htm>]). To simplify comparison, emissions of conventional pollutants are shown in terms of tons (or pounds) per year from a standard 550 MW unit that operates at an 85% capacity factor.

Table I. IGCC and PC Performance

Performance Characteristic	New Conventional PC^a	IGCC Current	IGCC Near-Future	IGCC 2020
Thermal Efficiency ^b	38.6 %	39.7 %	40.6 %	45 %
Sulfur Dioxide (SO ₂) (tons/year)	3,027	566	276	250
Oxides of Nitrogen (NO _x) (tons/year)	1,412	1,094	219	198
Mercury (Hg) (lbs./year)	45	29	29	26
Carbon Dioxide (CO ₂) (million tons/year)	3.7	3.6	3.5	3.2
Potential for Carbon Capture and Sequestration	Limited	Yes ^c	Yes ^c	Yes ^c

a. Based on performance of supercritical units currently undergoing environmental permitting. Advanced combustion technologies, such as ultra-supercritical pulverized coal boilers, may ultimately demonstrate performance characteristics similar to IGCC.

b. Thermal efficiency based on Pittsburgh #8 coal – data from EPRI.

c. Extent of carbon capture depends on facility design.

Table I indicates that the IGCC units that are initially deployed are likely to have somewhat higher efficiency and significantly lower emissions than conventional PC units with emission controls. The SO₂ and NO_x emissions from the near-future IGCC technology will be less than 20% of the already low levels of the PC unit. Mercury reductions and efficiency gains would also be significant. IGCC units would emit less CO₂ due to their higher thermal efficiency and provide a much less expensive option for carbon capture than current PC units. 2020 targets for IGCC show major improvements in thermal efficiency resulting in further reduction in all pollutants.

III. BARRIERS TO IGCC DEPLOYMENT

Despite the significant technological advantages of the IGCC technology—low emissions, high efficiency, and potential for carbon capture and sequestration—IGCC has not been commercially deployed in the U.S. or elsewhere. Low natural gas prices were a key reason for this in the 1990s. Today, two principal factors account for this: higher initial capital costs for IGCC, and industry concern that commercial-scale IGCC units pose technological risks that impact the reliability and availability of the unit.

There are significantly higher costs associated with building an IGCC facility when compared to the costs associated with constructing a traditional pulverized coal facility. According to EPRI data, the capital cost of an IGCC unit—in terms of \$ per kW of generating capacity—is about 14% higher than a conventional pulverized coal unit. This accounts for about half of the estimated 17-19% differential in the cost of electricity between a PC unit and an IGCC unit. (See Table III in Section VI.) Due to their significantly higher capital cost, the four IGCC units in operation today were built with partial government funding.

Technology risk—that is, the risk that full-scale units in commercial service will not have a level of performance at least equivalent to pulverized coal units—is an equally serious barrier to IGCC commercial deployment. A particular concern is the question of whether the unit’s availability, its ability to run continuously at full power without breakdowns, is equivalent to that of a conventional coal unit. Because of this perceived risk, the financial community imposes a risk premium on IGCC, limiting its market penetration absent some kind of financial incentive. IGCC facility design that includes a spare gasifier can mitigate part, but not all, of this risk.

Technology risk presents a particularly difficult challenge. As utilities and other entities undertake the commercial deployment of IGCC projects, they face numerous other risks—such as market price risks respecting their fuel supply and electric output, cost overrun risks, and regulatory and political risks—but these are not qualitatively different from risks that any company runs in building a conventional coal-fired power plant. For most of these risks there are commercially available instruments to mitigate these risks, including long-term fixed price fuel supply and power purchase contracts, fixed price engineering, procurement and construction (EPC) contracts, and various types of hedging contracts. What is not commercially available at reasonable cost, however, is an instrument for mitigation or hedging of technological risks. As a result, companies contemplating commercial deployment of IGCC technology face not only higher capital costs, but also technological risks that are likely to affect output and performance and cannot be hedged in today’s marketplace at reasonable cost.

The remainder of the paper reviews the effectiveness of a number of Federal financial incentives that have been proposed as means to reduce the cost differential between IGCC and conventional PC technologies and to mitigate the technology risk associated with IGCC.⁹ These incentive mechanisms include loan guarantees, direct loans, Federal cost sharing, four types of Federal tax incentives (investment credit, production credit, accelerated depreciation, and tax exempt financing), and Federal availability insurance. They are described below. The effectiveness of these incentives is reviewed for three classes of project owners: regulated investor-owned utilities (IOUs), independent power producers (IPPs), and public power/cooperatives. The incentive mechanisms are described in Section IV, and their usefulness to each class of project owner is discussed in Section V.

Attachment B to this paper addresses the question of how the Federal government analyzes the budgetary costs of the various incentives. Our analysis does not address this question at this time.

IV. TYPES OF FEDERAL FINANCIAL INCENTIVES

A. Federal Loan Guarantees

DOE and other agencies have been authorized under a number of different statutes to provide loan guarantees for development and commercial demonstration of advanced energy technologies. Loan guarantees permit a project sponsor to obtain debt financing at an interest rate closer to the Federal government’s cost of money. In addition, a loan guarantee may permit a highly leveraged capital structure for the IGCC project – substituting low cost debt for high

cost equity. Non-recourse loan guarantees can also shift a portion of a project's technology risk to the Federal government.

A useful example is DOE's authority under section 19 of the Federal Non-Nuclear Energy Research and Development Act of 1974 (the "Federal Non-Nuclear Act") which authorizes DOE to guarantee principal and interest on loans for construction and startup of "demonstration facilities" to produce alternative fuels from coal or other fossil fuel. The guarantee may not exceed 75% of projected project cost (60% for cost overruns), and the term of the obligation that is guaranteed cannot exceed 20 years (or 90% of useful life, if less).¹⁰

B. Direct Loans

Under a direct Federal loan program, the Federal agency—generally through the Federal Financing Bank—makes a long-term loan to the project owner to cover a portion of the cost of the facility. Interest rates vary depending on the program but are generally close to those on Treasury obligations of comparable terms.

C. Federal Cost Sharing

DOE and other agencies enter into a wide variety of cost sharing arrangements under which the Federal agency contributes a percentage of the capital cost of a commercial demonstration project. A current example of a cost-sharing program is DOE's Clean Coal Power Initiative (CCPI). Initiated in 2002, CCPI is a government/industry cost-shared technology demonstration program to foster more efficient clean coal technologies (CCTs) for use in new and existing electric power generating facilities in the United States. Candidate technologies are demonstrated at full-scale to ensure proof-of-operation prior to commercialization. DOE selects CCPI projects proposed by industry based on criteria in its financial assistance solicitation. The non-Federal cost share must be at least 50% of the total allowable cost of the project. Cost sharing may be in various forms or combinations, including cash outlays, and in-kind contributions. The government is under no obligation to share any cost overruns.

Applicants are required to repay 100% of the DOE actual contribution to the project upon successful commercialization of the technology being demonstrated. Repayment may come from various revenue streams including those from the demonstration project itself, royalties from sales and licensing of the demonstration technology in the United States and abroad, and/or any other source of funds the applicant chooses to propose.

D. Investment Tax Credit

Investment tax credits under the Internal Revenue Code provide the taxpayer a credit against regular income tax otherwise due, based on a percentage of taxpayer investment in specified equipment and facilities. The investment tax credit is one of 18 business tax credits that are available to corporations and other business taxpayers.¹¹ The investment tax credits under the current Code are 10% for certain capital investments in energy property, reforestation and rehabilitated buildings.¹² "Energy property" is limited to solar and geothermal equipment and facilities.¹³

Under current law, the use of the investment tax credit and most other business credits is constrained by a number of important limitations. First, the investment tax credit (along with the

other business tax credits) may not exceed 25% of regular tax otherwise due.¹⁴ Thus, a taxpayer who has no tax liability because of an unprofitable year will be unable to use the credit in the year in which it is earned. In addition, if the taxpayer reaches the 25% limit through use of other credits, the additional IGCC credit will not be useable in the current year.¹⁵ Second, the investment tax credit and other business credits are not generally allowable against the alternative minimum tax (AMT).¹⁶ (The AMT imposes a supplemental tax on taxpayers who make intensive use of tax preferences, such as accelerated depreciation, percentage depletion.)¹⁷ Thus, to the extent a company pays AMT rather than regular tax in a taxable year, under the Code's general rules, an investment tax credit will not provide it any benefit in that year.¹⁸ Third, as a general rule, under the Code, business tax credits are usable only by taxpaying entities.¹⁹ Municipal utilities and state power agencies cannot take advantage of them. Most cooperative utilities are also tax-exempt and unable to use business credits.

E. Production Tax Credit

A production tax credit provides the taxpayer with a credit against income tax otherwise due based on the amount of energy actually produced from a facility, rather than on the capital cost of the facility. Under current law, a 1.8¢/kWh production tax credit is available for certain renewable electricity production, including wind, biomass, geothermal, and solar.

In the context of IGCC, a key difference between the production tax credit and the investment tax credit is that with a production credit, the Federal government assumes none of the technology risks of the project – the production credit is allowable only to the extent the facility actually produces electricity. An investment tax credit, by contrast, is available without regard to the level of performance of the facility, so long as it has been placed in service.

The production tax credit is also subject to various structural limitations on the usability of the credits (discussed above in the context of the investment tax credit), including unavailability to state and local governments and most cooperatives, the limitation based on the amount of tax and AMT limits.

F. Tax-Exempt Financing

The general rule under the Code is that interest paid on obligations issued by state and local governments is exempt from Federal income tax, subject, however, to exceptions relating to private activity bonds (sometimes referred to as “industrial development bonds”). Under the private activity bond rules, obligations issued by a state or local government primarily for the benefit of a non-governmental entity are generally not tax-exempt. The Code, however, permits tax-exempt industrial development bonds for the benefit of private sector companies for particular purposes such as airports, local furnishing of electric and gas, district heating and cooling, and high-speed rail. Also, during the 1970s, tax-exempt industrial development bonds could be issued to finance investor-owned utilities' pollution control facilities. A similar provision for IGCC projects would lower interest rates and capital costs for IOUs and IPPs.

G. Accelerated Depreciation

The Code allows a deduction against gross income for depreciation, and specifies various methods for computing the allowance for depreciation. Moving an asset into a category that provides for a shorter recovery period (i.e., shorter tax life), or which permits most of the

depreciation to be taken in early years of the recovery period, increases the value of the depreciation deduction.

As with other tax incentives, accelerated depreciation provides no direct benefit to entities that are exempt from tax, nor any near-term benefit to unprofitable or startup companies who cannot use the deduction.

H. Availability Insurance

Federal availability insurance is a new concept which has not been spelled out in detail in legislation as of this time. Our analysis assumes an insurance program under which DOE issues availability insurance to the owner of a proposed IGCC project to cover a portion of the economic loss resulting from the project's not meeting its design availability target during its first ten years of commercial service. The project's design availability target would be specified in the insurance agreement, but could not exceed average annual availability of U.S. pulverized coal units equipped with FGD and SCR during the preceding 5 years. The economic loss covered in any year by the Federal insurance would be equal to project debt service multiplied by the percentage by which the unit misses its design availability target in a year. Not covered would be unavailability by reason of (i) force majeure, (ii) failure to follow good utility practice or applicable maintenance or warranty requirements, or (iii) defects of material or workmanship.

I. Other Incentives

Other incentives could be considered for IGCC (e.g., price guarantees). Price guarantees, however, are principally useful for mitigating market risk rather than technology risk and are not considered in the analysis.

V. USEABILITY OF INCENTIVES FOR PROJECT OWNERS

IGCC project owners have different credit standings, exposures to regulation, and sources of financing. Regulated investor-owned utilities, for example, use taxable debt and equity financing from non-governmental sources, generally have good credit standing but are subject to rate-of-return regulation. Municipal utilities, on the other hand, are not-for-profit, are unregulated, have good credit standing, and have access to low-cost tax exempt financing. Independent power producers use taxable financing, they are unregulated, and—at present—many have shaky credit standing at the corporate level, but have better credit standing at the project level for projects backed by a long-term power purchase contract. Because of these differences, the value of a particular incentive mechanism will vary depending on the type of entity that is proposing an IGCC project. This section describes some of the key factors that are significant in determining the value of particular incentives to different classes of project sponsors.

A. Regulated Investor-Owned Utilities

Electric utilities in about half of the States are regulated on a cost-of-service basis – that is, State regulatory commissions permit them to recover prudently-incurred operating expenses and a reasonable rate of return on prudently-incurred costs of facilities that are “used and useful” in providing utility services. The prudence and “used and useful” requirements mean that a utility

that incurs higher capital cost for an IGCC unit than it would for a pulverized coal unit of the same size is at risk of not recovering that cost increment in its retail rates. Regulators may also disallow costs incurred to purchase replacement power if the unit is not available for power production to the same extent that a conventional coal unit would be. A utility in these circumstances will seek advance approval from its regulators before proceeding with the project. The effect of the advance approval, if it is obtained, is to transfer much of the incremental capital cost and unavailability risk to the ratepayers. However, approval is not likely to be forthcoming if the capital cost increment or unavailability risk is unacceptably high. Thus, both utilities and regulators are likely to look for financial incentives that buy down the upfront capital costs of IGCC and, if possible, mitigate technology risks. Utilities, unlike other companies, are not in the position to bear the technology risk in return for higher potential returns since their regulators strictly limit their rate of return on equity.

Federal cost sharing and investment tax credits may be particularly useful to regulated utilities because they are an effective means of reducing upfront capital cost, and will have value even if the technology does not perform as expected. (By contrast, a production tax credit is useful only to the extent the unit is available and is run to produce power.²⁰) Loan guarantees on the other hand are not particularly useful to regulated utilities that, for the most part, have good credit standing and are not likely to benefit significantly from a highly leveraged IGCC project financing. A utility with a typical credit rating can obtain debt financing at interest rates that are about 1.5% above the Treasury's for obligations of similar maturity. And while more highly leveraged project financing arguably may lower the overall capital-related costs of an IGCC unit (by substituting low cost debt for higher cost debt) this reduction is estimated to be only about 0.5%, and will not result in a significant reduction in COE. For that reason, loan guarantees are not attractive to most utilities.

B. Independent Power Producers and Other Unregulated Firms

Independent power producers, utilities not regulated on a cost-of-service basis and other unregulated firms that are owners of IGCC units²¹ can use a set of financial incentives that are much different than those that are useful to regulated utilities. These firms differ in important respects from regulated investor-owned utilities. First, in many cases they have lower credit standing than regulated utilities, and thus have more use for Federal loan guarantees or direct loans. Our analysis assumes that IPP facilities are project-financed and that the projects have long-term power purchase contracts. Second, they may not have taxable income at the time they become entitled to a tax credit (or other tax incentive), and thus may not be able to use tax credits (or other tax incentives) until they become profitable. Third, they have no regulatory limitations on rate of return, and thus may be able to accept more technology risk because of the possibility that a successful project may be highly profitable.

For these entities, loan guarantees may be a useful incentive, providing some interest rate and leverage benefits and, perhaps as importantly, improving terms and availability of financing. Direct loans provide much more value, with the government supplying a lower interest rate and better terms than would be available in the private market. Tax incentives can be useful to profitable firms, and Federal cost sharing can be useful for firms that have access to capital to finance the non-Federal share.

C. Public Entities and Cooperatives

Public entities in this analysis include Federal, municipal, and state-owned entities. These entities are not-for-profit, generally unregulated, and for the most part highly creditworthy. For a highly creditworthy municipal issuer, for example, tax-exempt financing provides capital at interest costs lower than the Treasury's, and well below the cost of capital for most investor-owned utilities.

Customer-owned electric cooperatives are also not-for-profit, but are subject to rate regulation in about one-third of the states. Cooperatives that qualify for financing under the Rural Electrification Act have access to direct loans from the Federal Financing Bank at interest rates close to Treasury rates. Cooperatives that are taxable often distribute income to members in ways that leave them with no tax liability. For the purposes of incentive analyses they can be treated as tax-exempt.

Creditworthy municipal utilities are unlikely to use loan guarantees, since their cost of capital is already below the Federal government's. Cooperative utilities are also unlikely to benefit from using loan guarantees as they have access to Federal Financing Bank funding through the Rural Utilities Service at interest rates comparable to the government's rates. As noted above, municipal utilities and most cooperative utilities are tax exempt and therefore unable to benefit from investment or production tax credits or accelerated depreciation.

Tax-exempt financing does not provide a useful incentive to municipal utilities, since they already have access to tax-exempt financing. Nor would it be particularly useful for cooperatives that have access to the Federal Financing Bank at interest rates that are equivalent to the Federal government's cost of money.

The incentives that can be useful to municipal and cooperative utilities are Federal cost sharing (where the Federal government subsidizes a portion of the capital cost of the facility) and performance guarantees (which reduce the technology risk otherwise borne by the utility).

VI. EFFECTIVENESS OF FEDERAL FINANCIAL INCENTIVES IN STIMULATING DEPLOYMENT OF IGCC

To determine the effectiveness of alternative incentive mechanisms, we first calculate the "COE gap" – that is, the extent to which the cost of electricity (COE) produced by an IGCC plant exceeds the COE from a conventional supercritical PC plant. This cost of electricity calculation takes into account capital costs (debt and equity), thermal efficiency, fuel and other operating costs, capacity factors (i.e., the extent to which the unit actually produces power in a year), and technology risk.

The costs associated with technology risk were estimated by assuming that initially deployed IGCC units will have availability consistent with the experience of the two U.S. demonstration projects.²² Thus, IGCC has a lower availability than PC, which results in a decrease in capacity factor from 88% (for PC) to 78% (for IGCC). This lower capacity factor increases the COE by spreading the fixed costs over fewer MWhs.

Table XIV (in Attachment A) compares key parameters for cost and performance of current PC and IGCC technology (for initially deployed units) used in its COE analysis. Table XV (also in Attachment A) details key financial assumptions for the IOU, IPP, and Public power entities/cooperatives. The results of the COE analysis appear in Table II, and the computation of the COE gap in Table III.²³

Once the COE gap between PC and IGCC is determined, the effectiveness of the incentive mechanisms in closing the gap is estimated. This analysis is done for the eight incentive mechanisms (loan guarantees, direct loans, cost sharing, the four tax incentives, and availability insurance) as applied to each of the principal classes of project owners – investor-owned utilities, independent power producers, and public power/cooperative. The results of the analysis appear in Tables IV-XI.

A. Determination of COE Gap

Table II shows the comparative COE measures for IGCC and PC plants for the three classes of project owners. The COE estimates differ by ownership for a number of key reasons. First is the debt structure. Based upon typical industry practices, the IOU is assumed to use corporate financing with 55% debt. The IPP with a PPA is assumed to use project financing and achieves a higher leverage of 70% debt. Public power entities and cooperatives are assumed to use 100% debt financing. The next key factor is the cost of debt. Because the financial markets believe that the IPP has higher risk, it is assumed to demand higher return on equity (13% versus 11.5% for the IOU) and debt (8% versus 6.5% for the IOU). The Public entity's debt is not taxable to bond holders (for municipals), so the assumed interest rate is only 4.5%. In addition, the cost of the electricity depends upon tax treatment of income and expenditures. The IOU and IPP are assumed to pay both Federal and state taxes on income, with a combined rate of 39.2%. The public entity and cooperative are either non-taxable or do not pay taxes.

The COE cost of the IGCC plant is calculated with and without technology risk by examining two scenarios for plant availability. In one case, the IGCC plant is assumed to operate as designed by the end of its third year in service, averaging 88% availability over 30 years. In the technology risk case, the plant is assumed to operate more consistently with current IGCC experience, averaging 78% availability over 30 years. This technology risk case yields a higher COE since it spreads the same fixed costs over fewer MWh of generation.

These analyses of COE and our analyses of incentive value assume no electricity market risk.

Table II. COE Without Incentives (\$/MWh)

COE (\$/MWh)	IOU	IPP	Public/Coop
Supercritical PC	\$ 41.11	\$ 41.13	\$ 32.13
IGCC Without Technology Risk (88% capacity factor)	\$ 45.01	\$ 45.56	\$ 34.83
IGCC With Technology Risk (78% capacity factor)	\$ 49.01	\$ 48.90	\$ 37.53

Table III shows the estimated COE Gap. The cost difference between PC and IGCC without technology risk is largely attributable to IGCC’s capital cost and is referred to as “Capital Cost Gap.” The difference that is attributable to technology risk is referred to as “Technology Risk COE Gap.” The sum of the two is referred to as “Total COE Gap.” It is Total COE Gap that the Federal incentives are intended to bridge in order to permit the IGCC technology to be deployed.

Table III. COE Gap Without Incentives (\$/MWh)

COE Gap (IGCC – PC)	IOU	IPP	Public/Coop
Capital Cost Gap (without technology risk)	\$ 3.90	\$ 4.43	\$ 2.70
Technology Risk COE Gap	\$ 4.00	\$ 3.34	\$ 2.71
Total COE Gap	\$ 7.90	\$ 7.77	\$ 5.41

B. Determination of Value of Incentives

The estimated value of each incentive mechanism in reducing the COE gap is described below, together with key assumptions that underlie the analysis. It should be noted that the objective of the analysis is to estimate the value of the incentive mechanisms for representative entities in each owner class – the value of the incentives to a particular entity will, of course, depend on the financial circumstance of that entity and the specific terms in which the incentive is offered.

Loan Guarantees: The value of the loan guarantee incentive depends on the fraction of the plant cost that receives the guarantee and the reduced interest rate on the guaranteed loan. The yearly interest saving is the interest rate reduction times the outstanding debt during both construction and operation. These savings are present valued and then levelized across the unit’s production to determine the value of the incentive.

Based upon discussions with companies that deal with a broad range of Federally-guaranteed debt instruments, we have assumed interest rate savings would be 0.5% for the IOU and 0.8% for the IPP w/PPA. In both cases, the guarantee reduces the interest rate – but not to the rate for long-term Treasury bonds (T-bond rate) because even though the U.S. Government pays back the lenders in the event of default, delays, prepayment, and transaction costs make lenders demand a rate above the T-bond rate. Even without considering default, amortization and transactions costs lower the attractiveness to investors when comparing this offering to purchase of a T-bond. (The actual interest rate savings will depend upon the details of the legislation and market conditions when the loan is sought. The best case would be if the legislation were written so the asset owner could borrow directly from the government at, or close to, the T-bond rate. This case of a “direct loan” is modeled below.)

We assume that the loan guarantee covers up to 80% of the facility cost. We examine two debt-fraction cases for the IOU and IPP when they are offered this guarantee. In the first, they increase their debt fraction to 80%, receiving the interest rate savings across this 80% debt (note that the IOU would very likely lower debt fractions on other projects in order to maintain their traditional overall corporate debt structure). In the second case, we assume that they retain their more typical debt fractions for the IGCC project, receiving interest rate savings for a smaller amount of debt. In this second case, the IOU is assumed to finance 55% of the facility cost

(corporate financing) at the lower interest rate; the IPP with a power purchase agreement is assumed to finance 70% (non-recourse project financing) at this lower rate.

The estimated values of the incentive for each company type and debt fraction assumption appear in Table IV. The value of the loan guarantee is expected to be small for IOUs. The value to Public/Coop power owners is zero because they currently borrow at rates equal to or lower than the T-bond rate. The estimated value to the IPP may be somewhat greater than shown. While it includes the assumed interest rate savings and advantage of increased debt leverage, it does not include an explicit consideration of the value of improved borrowing terms, longer tenor, and expanded pool of possible investors, all of which could provide significant value to a project-based finance deal.

The estimates in Table IV do not include the cost of possible up-front loan fees. We have not estimated the cost of this program to the government and have no detailed analytical basis for estimating this loan fee. As a point of reference, an up-front loan fee of 3% of total project cost²⁴ would reduce these values by about \$0.80/MWh.

Table IV. Value of a Loan Guarantee (\$/MWh) With No Up-Front Fee

	IOU	IPP	Public/Coop
Base Case (increased debt fraction to 80%; interest rate reduced by 0.5% for IOU and 0.8% for IPP)	\$ 1.08	\$ 1.80	\$ 0
Reduce Interest Rates as in Base Case; Maintain Typical Debt Fraction	\$ 0.74	\$ 1.58	\$ 0

Direct Loans: This case analyzes Federal direct loans for 80% of project cost, available at the same interest rate as the 30-year T-Bond. Interest rate savings of 1.5% are assumed for an IOU and 3% for an IPP. As with loan guarantees, the value to public power owners is zero.

Table V. Value of Direct Federal Loan (\$/MWh)

	IOU	IPP	Public/Coop
80% Direct Loan	\$ 3.24	\$ 6.76	\$ 0

Federal Cost Sharing: The cost sharing percentage is assumed to be 10%. Cost sharing is assumed to be available during construction. The results are shown in Table VI. The base case assumes that the owner does not pay back the cost sharing. If the owner pays back the government over the first twenty years of plant operation, the value of the incentive drops. The value of these cost-sharing incentives scales with the percentage of the cost share. A 20% cost sharing grant would provide twice the values shown in Table VI. Also, the value can be increased or decreased somewhat depending upon the precise terms and timing of repayment.

Table VI. Value of 10% Federal Cost Sharing Grant (\$/MWh)

	IOU	IPP	Public/Coop
Base Case (no pay-back)	\$ 2.08	\$ 2.17	\$ 1.54
Pay Back Over 20 Years (no interest)	\$ 1.00	\$ 1.04	\$ 0.33

Investment Tax Credit: The investment tax credit (ITC) is assumed to be 10% of the plant cost. The ITC becomes available to the owner at plant startup. The results of the incentive are shown in Table VII. Since public power owners do not pay tax, the incentive is worth zero. If the company is able to use all of the ITC to reduce current tax liability, the value of the incentive scales with the size of the ITC; the 20% case has twice as much incentive value. A larger ITC increases the probability that some of the tax benefits from the credit might be received in later years. If, for example, the tax benefits are delayed five years on average, the credit would be worth about 25% less to an IOU or IPP. This issue of when the credits can be used is similarly important for the production tax credit and accelerated depreciation.

Table VII. Value of ITC (\$/MWh)

	IOU	IPP	Public/Coop
Base Case (10%)	\$ 2.29	\$ 2.37	\$ 0
20% ITC	\$ 4.58	\$ 4.74	\$ 0

Production Tax Credit: The production tax credit (PTC) rate is \$9/MWh for the first ten years of the plant operation. The results appear in Table VIII. Again, the value of the incentive (in \$/MWh) scales with the PTC amount.

Table VIII. Value of a \$9/MWh PTC for 10 years (\$/MWh)

	IOU	IPP	Public/Coop
Base Case – PTC (\$9/MWh)	\$ 4.24	\$ 4.23	\$ 0
Wind PTC Level (\$18/MWh)	\$ 8.48	\$ 8.46	\$ 0

Tax Exempt Financing: Tax exempt financing reduces the interest rate demanded by lenders. This reduction is applied to the outstanding bonds during construction and operation, present-valued to plant startup, and levelized over the project life. The interest rate is reduced by 31%, a figure implied by looking at the relative yields of non-taxable versus taxable debt instruments. The public owner already receives tax exempt status in this analysis (or borrows at the Treasury rate) and thus would receive no benefit from this incentive. Table IX shows the results.

Table IX. Value of Tax Exempt Financing (\$/MWh)

	IOU	IPP	Public/Coop
Tax-Exempt Financing	\$ 2.97	\$ 4.85	\$ 0

Accelerated Depreciation: Reducing the recovery period for tax depreciation provides the owner its income tax deduction for depreciation earlier in time. This time-value-of-money advantage translates into a lower COE when it is levelized. The base case reduced the twenty-year recovery period to the five-year period contained in recent legislation to stimulate investment. The results appear in Table X.

Table X. Value of Reducing the 20-Year Recovery Period to 5 Years (\$/MWh)

	IOU	IPP	Public/Coop
Accelerated Depreciation	\$ 3.14	\$ 3.33	\$ 0

Availability Insurance: Availability insurance is modeled by examining two scenarios for IGCC plant availability.²⁵ In one, it takes three years to reach the full design availability of 90%; the average availability over 30 years is 88%. In the other scenario, the plant is available 50% of time the first year, 60% the second, 70% the third and 80% thereafter; it never reaches its design availability and its average availability over 30 years is 78%.

The government is assumed to provide insurance for shortfalls below a negotiated availability target of 88%. The government insurance will cover a fraction of debt payment if a shortfall occurs, but does not provide any coverage of lost return on equity or fixed operating and maintenance costs. If the plant actually is available 78% of the time, insurance proceeds will cover about 16% of project debt service during the first 10 years of commercial operation. If the plant ramps quickly to 90%, the primary insurance needs will in the first two years of operation. Table XI shows the results. The insurance payment, as currently structured, falls well short of filling the \$4/MWh technical risk COE gap but has the potential benefit that it is paid out only when needed based upon actual plant operation.

Table XI. Value of Availability Insurance (\$/MWh)

	IOU	IPP	Public/Coop
4-Year Ramp Up to 80%	\$ 0.90	\$ 1.02	\$ 0.82
3-Year Ramp Up to 90%	\$ 0.29	\$ 0.91	\$ 0.21

VII. CONCLUSIONS

A. Summary of Relative Value of Incentives

Table XII shows the relative value of the various incentive mechanisms in bridging the COE gap (shown at the bottom of the table).

Table XII. Value of Base Case Incentives Compared with COE Gap (\$/MWh)

	IOU	IPP	Public/Coop
Loan Guarantee with No Fee	\$ 1.08	\$ 1.80	\$ 0
Direct Loan	\$ 3.24	\$ 6.76	\$ 0
Cost Sharing Grant (10% without repayment)	\$ 2.08	\$ 2.17	\$ 1.54
Investment Tax Credit (ITC) (10%)	\$ 2.29	\$ 2.37	\$ 0
Production Tax Credit	\$ 4.24	\$ 4.23	\$ 0
Tax Exempt Financing	\$ 2.97	\$ 4.85	\$ 0
Accelerated Depreciation	\$ 3.14	\$ 3.33	\$ 0
Availability Insurance (at 78% actual availability)	\$ 0.90	\$ 1.02	\$ 0.82
IGCC – PC COE Gap	\$ 7.90	\$ 7.77	\$ 5.41

B. Tailoring Incentives to COE Gap

No single incentive (as defined in its base case) provides enough COE value to make IGCC competitive with a PC. Table XIII borrows from existing proposals and other legislation to illustrate how incentives could be tailored to reduce or eliminate the COE gap between IGCC and the PC (shown at the bottom of the table). Every company would likely view the incentive packages somewhat differently, but these estimates provide insight into which are most likely to bridge the financial gap. The first tailored incentive combines a 20% ITC and accelerated depreciation. This package could make IGCC much more competitive for the two taxable entities. A second tailored incentive pays a production tax credit of \$18/MWh, equal to the current wind energy PTC. This more than fills the COE gap for the two taxable entities. (A \$15 to \$17/MWh PTC would achieve a rough breakeven COE for IOUs and IPPs.) Finally, 30% Federal cost sharing without repayment combined with availability insurance could make all IPPs and publics essentially indifferent between the IGCC and the PC on a COE basis, and leave a small gap for the IOUs.

Table XIII. Value of Tailored Incentives Compared with COE Gap (\$/MWh)

	IOU	IPP	Public/Coop
20% ITC + Accelerated Depreciation	\$ 7.72	\$ 7.06	\$ 0
Wind Energy PTC (\$18/MWh)	\$ 8.48	\$ 8.46	\$ 0
Cost Share (30% w/o repayment) + Availability Insurance	\$ 6.25	\$ 6.51	\$ 5.44
<i>IGCC – PC COE Gap</i>	<i>\$ 7.90</i>	<i>\$ 7.77</i>	<i>\$ 5.41</i>

Attachment A

Table XIV. Key Cost and Performance Parameters: Conventional PC with SCR and FGD vs. Initially Deployed IGCC (2004\$)

	Conventional Supercritical PC	IGCC (initially deployed units)
Capital Cost (\$/kW) ^a	1,300	1,485 ^b
Dispatched Capacity Factor	88 %	78-88 % ^c
Thermal Efficiency Heat Rate	38.6 %	39.7 %
Variable O&M (non-fuel – \$/MWh)	\$ 1.60	\$ 0.90
Fixed O&M (\$/kW/Year)	\$ 41.5	\$ 58.1

a. Does not include 10% owner's cost or interest during construction.

b. Includes technology royalty; assumes spare gasifier. IPP is assumed to purchase private availability insurance for \$60/kW, bringing its total capital cost to \$1,545/kW. The \$60/kW insurance price is calculated based upon the expected value of the insurance, rather than relying upon market data for this cost.

c. This calculation uses two availability scenarios, one reflecting design performance, one reflecting technological risk. The unit is assumed to be dispatched whenever it is available.

Table XV. Key Financial Assumptions for Different Project Owners

	IOU	IPP	Public
Fraction Debt	55 %	70 %	100 %
Cost of Debt	6.5 %	8 %	4.5 %
Cost of Equity	11.5 %	13 %	N/A
Tax Rate	39.2 %	39.2 %	0 %
Inflation Rate	2 %	F o r A l l	

Attachment B

Cost of Incentives to the Federal Government

A. Budget Process

Any disbursement by the Executive Branch from the Treasury first requires an appropriation by Congress.²⁶ The Congressional Budget Control and Impoundment Act of 1974,²⁷ overlays this constitutional requirement with a complex set of rules that have important implications for an IGCC incentives program. That Act specifies that each year the Congress will set overall fiscal policy by enacting a Budget Resolution which provides the committees of Congress with their individual “budgets” to spend.²⁸ The Congressional Budget Act also provides that the Budget Resolution may require Congress to enact a Reconciliation Bill to change permanent law (such as entitlements, or existing taxes or fees) with extraordinary procedural advantages in the Senate (it requires only a majority vote to pass, thus it cannot be filibustered). To implement the Congressional budget process, Congress also created the Congressional scorekeeping system, run by the Congressional Budget Office (CBO), to determine whether costs and revenues under legislative proposals are consistent with budget ceilings. Finally, certain procedural safeguards were adopted—such as pay-as-you-go (pay-go)—that require that any losses in tax receipts, or increases in entitlement spending, would be “paid for” by corresponding increases in tax receipts or cuts in spending. Some of these safeguards expired in 2003. As of early 2005, the House had not reinstated the pay-go rule, but it is still in effect in the Senate.

Finally, the Anti-deficiency Act²⁹ prohibits Federal agencies not only from spending Federal funds not appropriated by Congress, but also from entering into any contracts the disbursements for which have not already been appropriated. However, there have been frequent statutory exceptions to this contracting limitation.

B. Scoring IGCC Incentives

Scoring translates a complex incentive program into a single cost number for Federal budgeting purposes. Scoring is relatively simple for incentives that involve direct spending – such as a Federal cost sharing program. Budget authority is equal to the amount of the appropriation required for the program. In the case of tax incentives, scoring is based on revenue estimates by the Joint Tax Committee, which will quantify estimated revenue losses attributable to the particular tax incentive.

Loan guarantees present more complex issues. Specifically, the Federal Credit Reform Act of 1990 (“CFA”) provides that any Federal loan guarantees may be made only to the extent “new budget authority” to cover their costs is provided in advance in appropriations Acts.³⁰ The “cost” of a loan guarantee is the estimated net present value of payments by the government to cover defaults and delinquencies (netted against fees and recoveries).

What this limitation means in practice is that in order to receive a loan guarantee for a large-scale project, not only must there be statutory authority to issue the guarantee, there must also be sufficient new budget authority provided in an appropriations bill to cover the cost (i.e., credit risk) to the government associated with the guarantee. Credit risk is determined by CBO or by

the Office of Management and Budget (OMB) based on an assessment of the financial risk to the Federal government arising from a potential default by the buyer. CBO or OMB assess this risk based on the statutory limitations on the loan guarantee (i.e., percentage of project costs guaranteed, term of the loan, requirements for vendor performance guarantees and power purchase contracts, and creditor rights the government holds in the event of default) and other factors. For example, if CBO or OMB determined that there was a 10% risk of loss on a \$100 million loan guarantee, new budget authority of \$10 million would be required to cover that loss.

We have not estimated the cost to the Federal government of the incentives.

ENDNOTES

- ¹ Information sources for this section: World Coal Institute, Gasification Technologies Council, National Coal Council, Southern Company, U.S. Department of Energy National Energy Technology Laboratory.
- ² There are three major types of gasification systems in use today: moving bed, fluidized bed, and entrained flow. Entrained flow gasifiers are similar in concept to pulverized fuel firing; fluidized bed gasifiers are similar to fluidized bed combustors; and moving bed gasifiers bear some resemblance to grate firing. Currently, the demonstrated gasifier technologies are all entrained flow and include the coal/water slurry-fed processes (GE/ChevronTexaco and E-Gas™/ConocoPhillips) and the dry-coal-fed process (Shell/Prenflo).
- ³ Both of the European gasifier technologies are now owned by Shell and are commercially offered as Shell technologies.
- ⁴ While the KBR transport gasifier—which is being developed together with Southern Company at the Power Systems Development Facility—has shown promising results with low-rank coals, there are currently no commercially demonstrated gasification technologies that cost-effectively gasify lower rank coals such as lignite and sub-bituminous.
- ⁵ Holt, Neville, “Operating Experience and Improvement Opportunities for Coal Based IGCC Plants”, *Materials at High Temperatures*, 20(1) 1-6, 2003. Note that this report also indicates that mercury removal was not required at any of the existing demonstration facilities, but that estimates are based on mercury removal from the syngas produced at the Eastman Chemical coal gasification facility operating for the past 18 years.
- ⁶ Utility Data Institute’s North American Business Directory, data through 1997. No new coal plants have been built since 1997 that would change this data.
- ⁷ National Coal Council Report, “Opportunities to Expedite the Construction of New Coal-Based Power Plants” November 2004. Additional benefits of IGCC systems: they use less water than traditional PC plants and produce little solid waste; byproducts formed from the mineral matter in the coal can be collected and used for many purposes, such as building roads.
- ⁸ Instead of burning the coal derived syngas to generate electricity, it can also be processed using commercially available technologies to produce a wide range of fuels, such as diesel oil, chemicals, and fertilizer or industrial gases. Some facilities have the capability to produce both electricity and other products from the syngas, depending on the plant’s configuration as well as site-specific technical and market conditions. This process is referred to as “co-production” or “poly-generation.” The hydrogen output can be a valuable input for refiners and chemical manufacturers.
- ⁹ We do not address in detail other possible IGCC deployment paths, such as refueling existing natural gas combined cycle plants, that might be encouraged through incentives. These investments would face some of the same technical risks as the overall IGCC plant investment.
- ¹⁰ The terms “demonstration facility” and “alternative fuel” are undefined, but both the statutory context and experience under this program indicate that full-scale commercial demonstration projects are within the ambit of this program, and it would appear that an IGCC gasifier would qualify for assistance. Loan guarantees on projects in excess of \$50,000,000 must obtain specific legislative authorization before the guarantee is issued.
- ¹¹ Internal Revenue Code of 1986 (“Code” or “IRC”) § 38(b) (1986). (These credits include, among others, the renewable energy production credits, solar and geothermal tax credits, alcohol fuel credits and enhanced oil recovery credits.)
- ¹² *See id.* § 46, 47, 48.

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- ¹³ *See id.* § 48 (a)(3).
- ¹⁴ *See id.* § 38 (c)(1)(B). “Regular tax” excludes the alternative minimum tax and certain other special tax provisions. *See id.* § 26(b). The 25% rule does not apply to the first \$25,000 of regular tax otherwise due.
- ¹⁵ *See id.* § 39. The Code, however, provides for a 1-year carryback and a 20-year carryforward that mitigate the impact of this limitation.
- ¹⁶ *See id.* § 55, et. seq.
- ¹⁷ *See id.* § 38 (c).
- ¹⁸ *See id.* §38 (a)(3). However, carrybacks and carryovers may be available, and the Code provides exceptions for certain favored credits.
- ¹⁹ The Code does provide for certain refundable credits for individuals, and for refunds under the income tax system of overpayments of excise taxes. Recent proposals for transferable renewable generation tax credits for these entities have not been successful in the Congress.
- ²⁰ Another factor in evaluating the usefulness of Federal financial incentives is the “tax normalization” policy under Federal tax law. That policy conditions the availability to regulated utilities of certain tax incentives (such as accelerated depreciation) on the utilities’ regulators allowing the utility to retain the benefit of the incentive.
- ²¹ Unregulated IGCC owners could include equipment vendors, coal producers, or industrial companies.
- ²² The availabilities are not directly comparable. One existing plant experienced a commercial dispute with a contracting party. Also, both U.S. plants are often used as test beds for technology development research.
- ²³ The COE is calculated with EPRI’s Technical Assessment Guide (TAG) 1997 methodology and spreadsheet model. The model produces the detailed cash flows associated with a single power plant investment and operation. The model represents the regulation of an investor owned utility (IOU). The cash flows depend on the cost and performance of the power plant and the details of the rate regulation. The results of COE are measured in levelized constant 2004 dollars per megawatt hour. The COE reflects such factors as interest during construction (AFUDC), the return on and of capital, and normalization of tax timing advantages. The levelized COE is calculated at the after-tax cost of capital.

The TAG model is used to calculate the value of incentives for two kinds of ownership – IOU and IPP. These types use different inputs in the EPRI spreadsheet to model the asset owner. Examples of input data that changes are debt and equity fractions, cost of debt and equity, and income tax rates. While the TAG model carefully represents an IOU, it also calculates the COE for IPP owners. IOU regulation varies across the country. However experience shows that these differences cause minor changes in COE. IPP owners may use other ways of calculating COE, but the impact of incentives on their COE is approximately represented by TAG. Finally, rate making at Public Power utilities does not mirror the TAG results. A separate spreadsheet has been constructed to calculate COE for these organizations. These methods define the Public Power COE with acceptable accuracy.

COE is a good measure of technology attractiveness. However, it will not determine project owner behavior in every instance. This analysis compares the IGCC plant with a PC plant. Some organizations may find that strategic or profitability issues indicate that they should invest in nothing or in alternatives such as nuclear, gas fueled generation renewables, and/or DSM. Of course, a company that believes its financial future depends on being able to develop and operate IGCC plants may invest in their first IGCC plant with a COE disadvantage. The COE method does not monetize any differences between IGCC and PC by using prices for SO_x, NO_x, mercury or CO₂ emission allowances. Such monetization would close the COE gap somewhat (by about \$0.50 today for SO_x and NO_x). Looking forward, increasing environmental costs could decrease the gap by around \$1.00 by 2010 given current forward market estimates, but would also make all coal plants relatively less

attractive compared to other lower emitting generating technologies. Finally, while the COE method is a good way of understanding how various incentives can bridge the COE difference, the COE results cannot be compared between different ownership types because of the detailed assumptions in the methods.

- ²⁴ Fees can vary greatly. Several internet sites provide example calculators for estimating these fees (note that the actual fee can vary from the calculator result). An ExIm Bank loan to the government of Canada drawn down over 36 months that is paid back over 30 years has a fee of about 4%. Reducing the draw down time or the payback period reduces the fee. A Transportation Infrastructure Financing loan for a BBB+/Baa1 debtor has a fee of 1.6% for a 4 year draw down and 25-year payback loan. A B/B2 borrower has a fee of 16.17% for the same loan. Berg and Paterson (David.Berg@hq.doe.gov) provide a deeper level of explanation as well as several examples in a January 29, 2004 presentation.
- ²⁵ Availability refers to overall plant availability, rather than just the availability of syngas. In all calculations, we assumes that the IGCC dispatches when available. A backup fuel supply for the combined cycle gas turbines can lessen availability problems, but due to heat rate inefficiencies and fuel cost, is unlikely to be used (dispatched) often.
- ²⁶ U.S. Const. art. I § 9, cl. 7.
- ²⁷ Pub. L. No. 93-344 (codified as amended in scattered sections of the U.S. Code).
- ²⁸ In addition, the Appropriations Committees are required to subdivide their 302 (a) allocations among their subcommittees. These are called 302 (a) allocations, after the section of the Congressional Budget Act that requires them to be made.
- ²⁹ 31 U.S.C. §§ 1341, 1342, 1349-1351, 1511-1519.
- ³⁰ Budget authority is a provision of law that makes funds available for obligation and expenditure, or contract authority to incur obligations.