CCT'S IN A DEREGULATED ENVIRONMENT:

A PRODUCER'S PERSPECTIVE

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ABSTRACT

The U.S. electric industry will be deregulated (or substantially re-regulated) within 5 years. Several states, including California, Rhode Island, and New Hampshire, already have passed legislation to introduce competition into the electric markets before the year 2000. As this trend sweeps across the country, the resulting competitive market for generation will reward the lowest cost producers and force high cost producers out of the market. As a result, at least in the short run, it may be very difficult for new power plants employing Clean Coal Technologies (CCTs) to compete. This paper discusses a producer's perspective of the new competitive market, and suggests several short and long term strategies and niches for CCTs.

I. INTRODUCTION

For more than 60 years, the electric utility industry has been highly regulated, as were industries like banking, trucking, telecommunications, and natural gas. But starting in the early 1970s, the United States began witnessing a transition from an environment of regulation to one in which market forces held greater sway. One by one over the next 20 years, these industries saw the regulatory veil lifted, exposing them and their customers to the benefits and uncertainties of market competition.

Throughout this period, many continued to believe that utilities were different and that deregulation was impractical and unnecessary. In the 1990s, however, the same forces that nurtured change in other industries — customer expectations of lower cost, more choice, greater innovation and better service — began to affect the electric utility industry. Today, the transition to a more competitive environment is well under way.

Global competition, coupled with rate disparities that can exist between assigned service territories, is the primary force behind the push for a market-driven electricity utility industry. As U.S. industries find themselves competing toe-to-toe with not only domestic but foreign enterprise, the pressure to keep production costs down is intensifying. As a result, industries are leading the call for a competitive electric market in the U.S. Many views exist of how a competitive market might function. Duke Power believes(1) a national market will evolve and that it will look much like the one now being developed in California.

Regardless of the form, there are a number of significant issues that can affect customers and the shareholders of publicly held utilities like Duke Power Company. These issues include:

- Maintaining fairness and equity between customer classes (e.g. residential, commercial, and industrial)
- Ensuring the world's most reliable electric system remains so
- Maintaining parity among competing suppliers (e.g. subsidized generators are not allowed to compete with unsubsidized generators)
- Redefining the monopoly-based obligation to build generation to serve all assigned customers
- Recovering stranded investment
- Allocating equitable sharing of societal costs

These are difficult, critical issues, but if they can be fairly and appropriately resolved Duke Power supports the concept of electric utility deregulation. Duke advocates federal legislation to provide guidance to the states for implementing deregulation, including a time frame under which it would be instituted. Following federal action, each state should then be allowed to design its own specific solutions. Duke PowerÕs position on restructuring the industry is based upon the simple premise that deregulation should offer equal treatment of all customers, provide a level playing field for all competitors, and maintain the current high reliability of the electric system.

II. ONE VIEW OF A DEREGULATED INDUSTRY

While there are three primary functions of the electricity utility business (generation, transmission, and distribution), most proposals for deregulation are limited to the generation business because of its present level of competitiveness. Even in a competitive environment, the transmission and distribution businesses would most likely be separate entities under the regulation of the Federal Energy Regulatory Commission (FERC) and state regulatory commissions.

A number of proposals have been made concerning deregulation. Among the many competitive market proposals considered, one promising idea for restructuring calls for creating a new structure built on two fundamental concepts:

- The primary source of electricity for all customers could be through a regional power pool. Participants in the power pool would primarily be generators, customer representatives referred to as ÒaggregatorsÓ or Òretail companiesÓ, and end-use customers.

- A secondary source of electricity could be through bilateral contracts between willing generators and end-use customers or aggregators.

A power pool could be comprised of two new regulated organizations: the Power Exchange (PX) and the Independent System Operator (ISO). Both would be independent businesses that would be governed and managed separately from the financial interests of market participants. Whether management of the PX and ISO would be separate entities is still an open question, but the roles and responsibilities of each are best described separately.

The Power Exchange

The role of the PX could be to facilitate trading in a visible spot market in which generating resources compete by:

- Taking supply bids from generators and demand bids from utilities, retail companies, power marketers and others;
- Allowing power producers to compete using non-discriminatory and transparent rules for bidding into the exchange;
- Ranking bids and submitting to the ISO a preferred least-cost dispatch schedule for delivering power; and
- Providing a visible market clearing price to permit customers to make efficient purchasing decisions and to adjust consumption.

Independent System Operator

The ISO would provide daily transmission system information to all market participants and collect bids by market participants to provide ancillary services for the next day. The ISO would control the transmission system and coordinate the hourly dispatch of the generation system in a reliable manner. The ISO could:

- Provide non-discriminatory open access to the transmission network;

- Coordinate day-ahead scheduling for all transmission network users;

- Control operation of the combined transmission facilities of the participating transmission owners;

- Obtain ancillary services, (reserves, for example) for all transmission network users on a competitive basis;
- Perform a settlement function to account for actual operating conditions ;
- Provide transparent information flow to all transmission network users;
- Facilitate bilateral contracts between generators and customers;
- Comply with all operating and reliability standards; and
- Manage transmission congestion and constraints on a network basis with all users subject to the same terms of access, protocols and prices.

Transmission congestion charges could be administered by the ISO (in accordance with FERC approved tariff provisions) to provide pricing signals as inducements to market participants to build congestion-relieving transmission upgrades in needed areas. A separate mechanism or regulatory "backstop" may be put in place if generation or transmission is needed for the sake of reliability and the market fails to react appropriately. The ISO will not own any transmission or generation resources, but could have compelling incentives to help ensure system reliability.

Figure 1 illustrates the basic concept of a power pool.

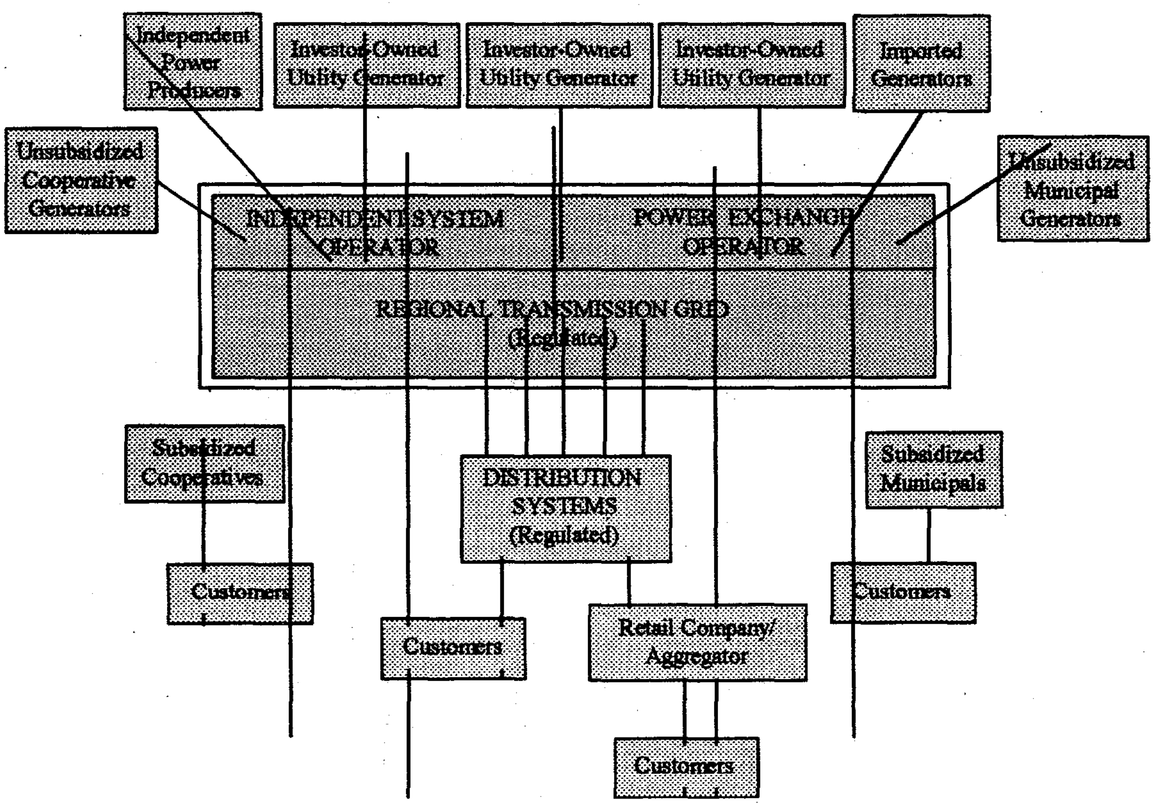

Figure 1. Basic Power Pool Operation

This combination of a PX, an ISO, and bilateral contracts is sometimes referred to as a "flexible pool" because it is designed to provide flexibility in contracting and trading arrangements. The flexible pool could offer all consumers electricity at competitive prices and also give all generators an equal chance to serve the available customer base. In some cases, an aggregator or a retail company could procure and provide these competitively bid generation services to customers.

While many details must still be resolved, the basic concept for the flexible pool could provide the foundation for advancing competition without compromising reliability or giving any competitor an unfair advantage.

III. CCTs IN THE DEREGULATED MARKETPLACE

If the marketplace described above comes to pass, it will have a number of impacts on the use of CCTs, some positive, but most negative--at least in the short run.

Lowest Operating Cost Wins

First, the competitive generation market will be more difficult for <u>any</u> new entrant, but especially so for plants with higher capital and operating cost. If existing plants are allowed to recover their *stranded costs*--i.e. that portion of their fixed costs not otherwise recovered by the competitive price of power--then any <u>new</u> plant will have difficulty competing with <u>existing</u> generators. This will hold true until the existing excess generating capacity is depleted. (Note: Depletion could be the result of demand growth, obsolescence of older plants, environmental/regulatory action against an existing technology, etc.) Then, when new generation is needed anyone considering entering the market will ask themselves these questions:

Which technology will produce power for the least overall cost?
- ➪ High cost = non-competitive
- ➪ No more automatic cost recovery in utility rates

Which technology has the least risk--technical and financial?
- ➪ Risk translates into higher cost

Which technology can be brought on line quickest?
- ➪ Time is money
- ➪ Competitive markets can be fickle, change rapidly

Currently the answer to all these questions would be combined cycle gas turbines in either a stand-alone power plant or in a cogeneration mode. As long as gas prices remain reasonably low, gas turbines will continue to be the technology of choice.

Technology Risk is a Killer

Technology risk associated with new CCT-based generators will cause these plants to suffer in the competitive market for two reasons. First, the equipment cost will have a "technology premium" to cover development costs and performance risk. Second, and probably more critical, the project owners will pay a risk premium on any borrowed funds. Lenders have shown little appetite for risk in the independent power market that has dominated the placement of new capacity for the last decade. There will be even less appetite for risk where the payment stream used for debt coverage comes from the competitive marketplace and not a "secure" long term contract with a utility, as existed in the recent past.

The "Level Playing Field" Issue

A potential obstacle to new CCT-based generation is the notion that in a competitive generation market, no generator should be allowed to compete if it receives a subsidy--such as tax-exempt bonds or government loans--that is not available to all generators. This position is held by most investor-owned utilities, including Duke Power. And, since approximately 80% of all generation in the US is owned by investor-owned utilities, this position is likely to prevail. If it does, it would mean that CCT projects which received DOE grants or loans would either have to seek special status or find ways to mitigate their competitive advantage.

Fuel Diversity is a Wild Card

Potentially the greatest advantage CCTs have in the deregulated marketplace is that they provide fuel diversity. But it is unlikely that producers, left to their own devices, will place much emphasis on fuel diversity, especially in the near term. However, two things could change that likelihood. First would be a near-term spike in gas prices. The US has seen a decade of stable, even falling, gas prices. This has caused a widespread shift away from coal and toward gas-fired technologies. Another oil embargo, a Gulf crisis, or a natural disaster in a major gas-producing region could push gas prices up to the point where generators will choose an alternative fuel.

Alternatively, the federal or state governments could weigh into the utility deregulation debate with their concerns about fuel diversity. It will likely take government intervention to force fuel diversity arguments to be heard. It appears, based on positions published before the recent election, that while the Clinton Administration is lukewarm toward electric deregulation, it will insist that fuel diversity be considered in future rules. States also, to the extent they are involved in setting the deregulation rules, may insist on fuel diversity and, possibly, use of indigenous fuels like coal.

Environmental Issues--Mixed Bag

Environmental issues are a mixed bag in terms of their impact on deployment of CCTs. Emissions limitations could force owners of older coal-fired plants to retrofit CCTs to comply with more stringent limits. This could be particularly true where older plants, many with minimal emissions controls, are pressed into service in the competitive marketplace. Capacity factors could increase dramatically on these plants as the competitive price of energy increases due to increased demand. Indeed, there is a fear among many environmentalists that this is precisely what will happen. CCTs could mitigate that fear.

But while environmental issues could increase the use of CCTs retrofitted to older plants, there does not appear to be a similar beneficial impact on new CCT-based plants. This is true because currently even the best CCT environmental emissions are no better than those from similar-sized gas turbine plants. The impressive environmental records of many of the new CCTs can certainly be used to *support* their use (for example to mitigate fuel diversity concerns) but environmental records alone will not endow a marketplace advantage on CCTs vis-à-vis gas plants.

IV. CCT OPPORTUNITIES

The major cost drivers for a new power plant are capital cost and fuel (including transportation) cost. It is currently a universally recognized fact that there are few, if any, places in the US where a coal plant can produce power cheaper than a gas-combined cycle plant, provided gas is available. And there are only two states, Hawaii and Maine, where natural gas is not available. Therefore, unless promoted for fuel diversity reasons, coal must either find ways to reduce the all-in cost of power or find niche opportunities.

Reducing Conventional Coal Plant Costs

Although the focus of this paper is on the future of CCTs, it is instructive to look at the competitiveness of a conventional coal plant in today's environment. One of the most recent conventional coal-fired plants to be brought into service in the US was Cope Generating Station, completed in late 1995 by Duke/Fluor Daniel, a Duke Power affiliate.(2) This plant, built for South Carolina Electric and Gas, is the least cost coal plant built in recent years. The $411 million plant generates 385mw at 95% valves open. At full valves open, this equates to a little over $1000/kw of capacity.

In building the Cope plant, Duke/Fluor Daniel utilized a number of cost cutting measures which had been developed in several recent international plants. Most effective were (1) world-wide sourcing of equipment, and (2) a sophisticated Computer Aided Design package developed by Duke/Fluor Daniel called PowerSuite. These and other cost saving techniques can keep the cost of coal plants down, but, as illustrated below, more is needed if coal is to compete with gas.

In contrast to the $1000/kw price for coal plants, similar sized gas combined cycle capital costs are approximately $500/kw. Assuming roughly equal O&M costs (a generous assumption for coal), approximately a 50% to 35% efficiency advantage for gas, and gas at $3.00/mmBTU, then coal prices per million BTU must be around <u>$1.00</u> to be competitive. See Table 1 below.

	Coal Plant	Gas Combined Cycle Plant
Capital Cost	$1000/kw	$500/kw
Efficiency	35%	50%
Fuel Cost*	$1.05/mmBTU	$3.00/mmBTU

*For power cost from coal to equal gas at $3.00, coal must be this

Table 1. Comparison of Coal And Gas Plants

Therefore, with existing capital cost and efficiencies for coal and gas plants, coal prices must be less than gas by a 3:1 margin to make the generation owner indifferent to technology. Put another way, gas prices would have to suffer a 50% increase before coal at $1.50/mmBTU would become cost competitive.

The only place in the US where coal can currently be obtained for $1.00/mmBTU is at the mine. Consequently, mine-mouth coal plants can be competitive. In the fully competitive marketplace described above, i.e. open, boundary-less transmission access, mine-mouth power plants may be an attractive option.

CCTs as Backup to Gas

As noted above, gas combined cycle plants have a significant advantage over conventional coal today. Gas can also beat any known CCT including coal gasification and PFBC. But that doesn't mean there is no place for CCTs. In fact some gas combined cycle plants being built today have included space to convert to coal gasification-combined cycle later. But one shouldn't look for CCT hardware orders soon, because no generation owner can afford to invest capital in a backup technology until there is a clear pricing signal that the fuel price advantage of gas is on the verge of changing.

Co-Production

Among the CCT's that are demonstrated and nearing commercial availability, coal gasification-combined cycle (CGCC) technologies may have a slight market edge over others since they are capable of co-production. CGCC plants are, in the simplest terms, a chemical plant that produces synthetic natural gas along with other useful byproducts such as steam, hydrogen, ammonia, sulfur and re-useable ash products. Therefore, in addition to producing useful steam and electricity in a classical cogeneration configuration, CGCC plants are capable, with additional capital investment in the gas production portion of the plant, of producing revenue-producing byproducts. Revenues from the co-production of useful chemicals and solid byproducts, to the extent they are greater than the carrying cost of the extra capital employed to produce them, can be used to reduce electricity costs. This scheme may be particularly effective if co-located with a major petrochemical plant or other chemical-based manufacturing facility.

Alternative Fuels

Although not a new idea, the concept of using alternative fuels as a substitute or supplement to coal in a CCT may allow the CCT to penetrate the market earlier than a plant fueled by coal only. Fuels like petroleum coke, sewage sludge or waste coal have been proposed by others.

V. CONCLUSIONS

The coming deregulated electric market will reward the lowest cost producers of power and punish all others. CCTs that allow older, lower cost coal plants to continue operating without pushing their production costs above the competitive price of electricity will have a bright future. New coal plants that employ CCTs must be able to generate at lower production costs than gas in order to be considered by any producer wishing to stay in business. It is not a question of "Will CCTs be a player in the deregulated marketplace?", but rather a question of "when". Or more precisely, "When will electricity prices, gas prices, and capital cost of CCTs converge favorably to the point where a generation owner will invest in the CCT?" But, in the meantime, there are some strategic reasons and some niche opportunities that may work to allow CCT-based capacity to penetrate the market earlier.

VI. REFERENCES

(1) "Restructuring the Electric Utility Industry: A Position Paper", Duke Power Company, November 1996.

(2) "Electricity Flows from New SCE&G Generating Plant", News Release, South Carolina Electric and Gas Company, January 15, 1996.

MARKET FOR NEW COAL POWERPLANT TECHNOLOGIES IN THE U.S. 1997 ANNUAL ENERGY OUTLOOK RESULTS

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ABSTRACT

Over the next 20 years, the combination of slow growth in the demand for electricity, even slower growth in the need for new capacity, especially baseload capacity, and the competitiveness of new gas-fired technologies limits the market for new coal technologies in the U.S. In the later years of the 1997 Annual Energy Outlook projections, post-2005, when a significant amount of new capacity is needed to replace retiring plants and meet growing demand, some new coal-fired plants are expected to be built, but new gas-fired plants are expected to remain the most economical choice for most needs. The largest market for clean coal technologies in the United States maybe in retrofitting or repowering existing plants to meet stricter environmental standards, especially over the next 10 years. Key uncertainties include the rate of growth in the demand for electricity and the level of competing fuel prices, particularly natural gas. Higher then expected growth in the demand for electricity and/or relatively higher natural gas prices would increase the market for new coal technologies.

I. Key 1997 Annual Energy Outlook Results

Over the next 20 years the demand for electricity is expected to continue to increase with economic growth (Figure 1). However, the combination of increased market saturation of electric appliances, improvements in equipment efficiency, utility investments in demand-side management programs and legislation establishing more stringent equipment efficiency standards has slowed the rate of growth from the level seen in the 1960s and 1970s. Overall the demand for electricity is projected to grow 1.5 percent annually, with the residential and industrial sales growing faster than commercial sales (Figure 2).

The need for new capacity, especially baseload capacity, is expected to grow slower than total demand. Between 1995 and 2015 total U.S. generating capacity increases from 767 to 970 gigawatts, an annual rate of increase of 1.2 percent. However, due to the expected retirements of 38 gigawatts of existing nuclear capacity and 71 gigawatts of existing fossil-steam capacity, total capacity additions amount to 310 gigawatts over the next 20 years (Figure 3). Nuclear plants are assumed to retire at the end of their 40-year license period or before if their operating and maintenance costs exceed 4.0 cents per kilowatt hour. Fossil-steam plant retirements include reported retirement plans from utilities and the retirement of high operating cost units that would not be competitive in a deregulated environment.

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015 (Index, 1960 = 100)

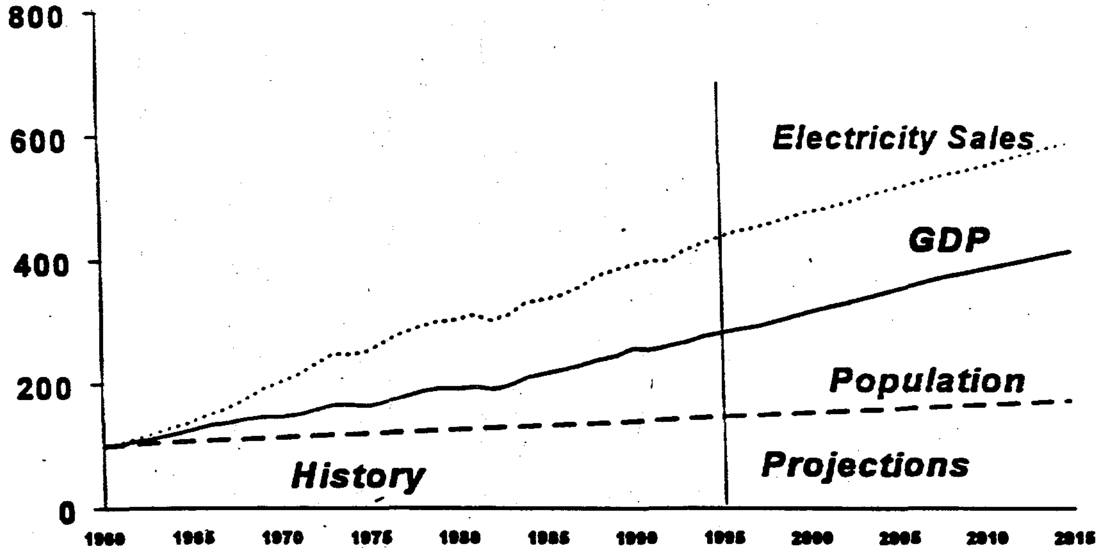


Figure 2. Electricity Sales by Sector, 1970 - 2015 (Billion kilowatthours)

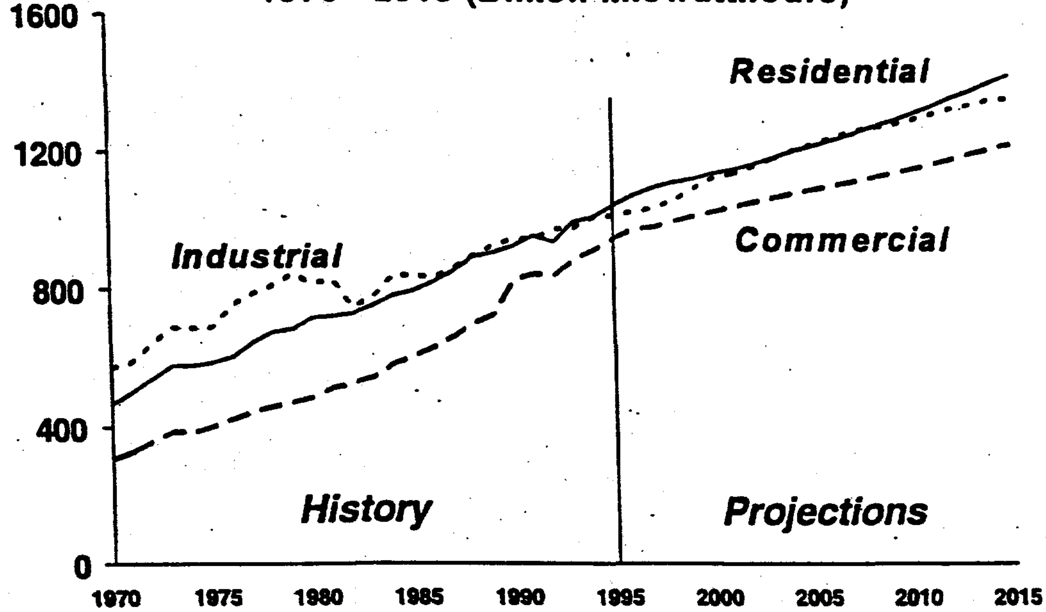
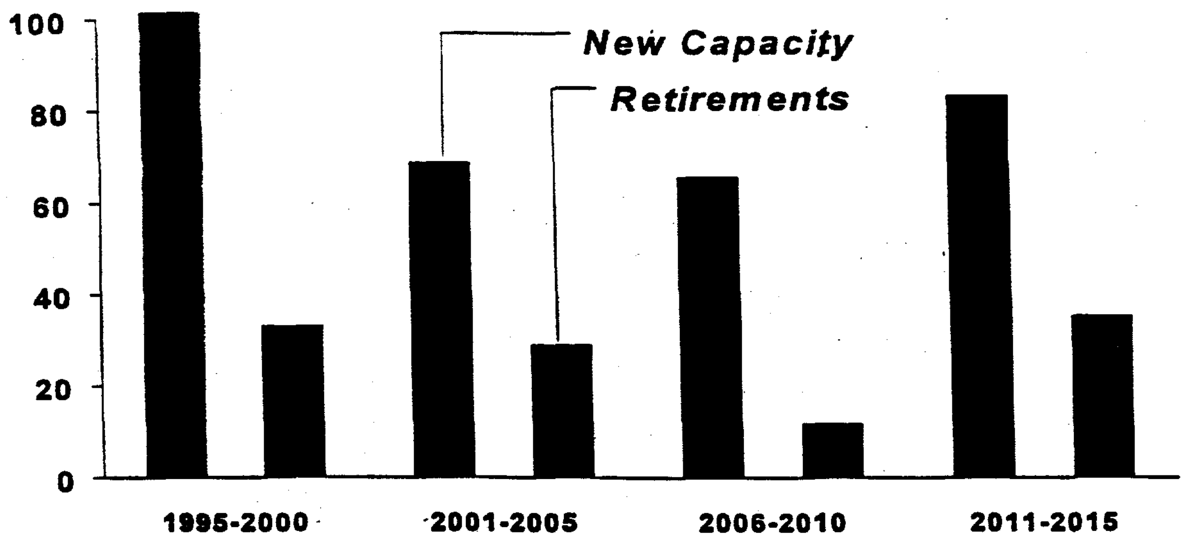


Figure 3. New Generating Capacity and Retirements, 1990 - 2015 (Gigawatts)



Natural gas-fired combustion turbines and combined-cycle units are expected to dominate new plant additions, especially in the near-term (Figure 4). About 80 percent of the capacity additions over the 1995 through 2015 period are projected to be gas-fired. Coal-fired and renewable (and other) plants account for the remaining capacity (11 and 8 percent, respectively). In the near term, between 1995 and 2000, new capacity is expected to be built to meet peaking needs. As a result, 65 percent of the gas-fired capacity built in that period are simple combustion turbines while the rest are combined-cycle plants. This pattern reverses itself in the last five years of the forecast when new plants are needed to serve growing baseload and intermediate demands. Over this 5 year period combined-cycle plants account for about 75 percent of the gas-fired plants added.

It is also during the later years of the forecast, 2005 to 2015, when most of the new coal plants projected to be added are brought on line. About 70 percent of the 37 gigawatts of coal plants projected to be built between 1995 and 2015 are brought on-line in 2005 and later. Over the 20 years of the projections, gas and coal prices to powerplants slowly diverge, with gas prices rising at approximately 1 percent per year (most of this increase occurs after 2005) while coal prices decline at a rate of 0.9 percent annually (Figure 5). In some regions of the country this widening fuel cost differential is large enough to allow new coal plants to be competitive with gas plants even though they cost much more to build. The vast majority, approximately 75 percent, of the

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995 - 2015 (Gigawatts)

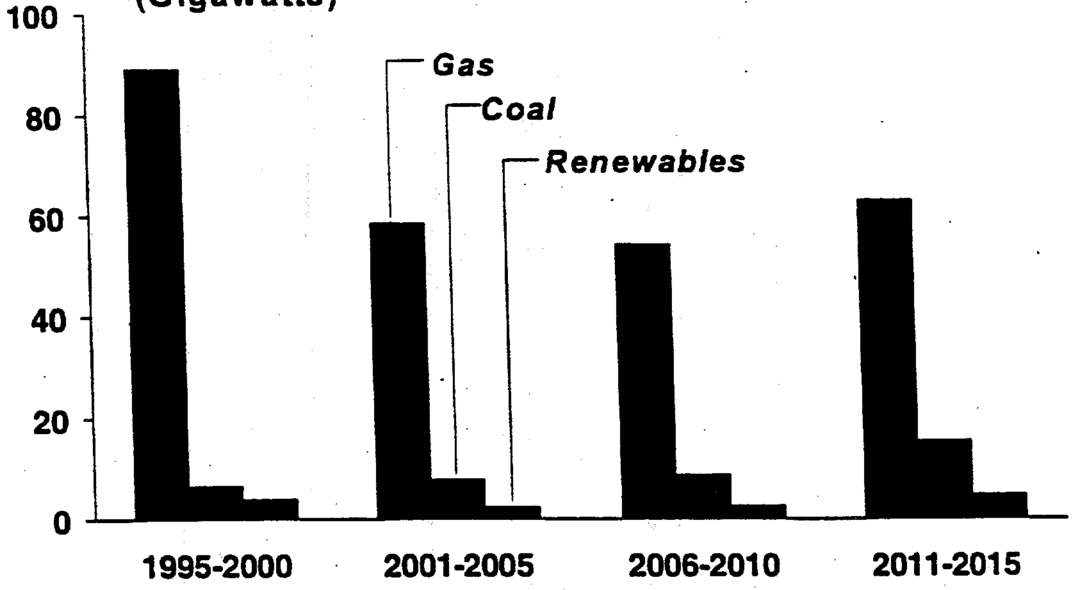
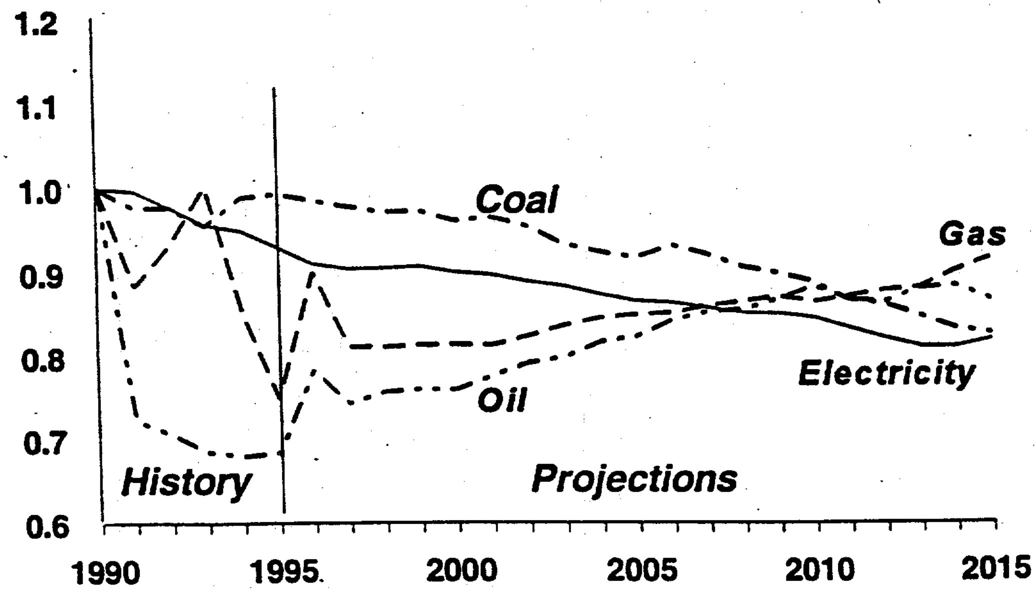


Figure 5. Fuel Prices to Electricity Suppliers and Elect Prices, 1990 - 2015 (Index, 1990 = 1.0)

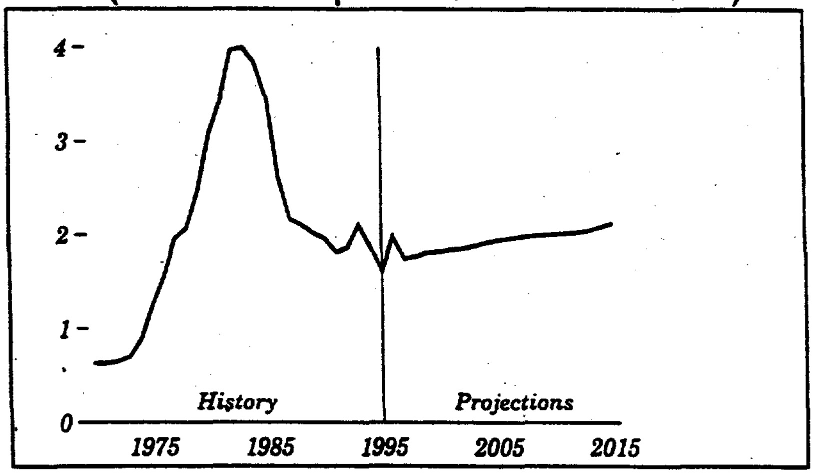


coal plants built are expected to be conventional pulverized coal plants with the remaining being integrated coal gasification plants (IGCC).[1]

II. Natural Gas, Coal, and Electricity Prices

Wellhead prices for natural gas in the lower 48 States increase by 1.4-percent annually in the reference case (Figure 6) reaching $2.13 per thousand cubic feet (in 1995 dollars) in 2015. The price increases reflect the rising demand for natural gas and its impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. In *AEO97*, technological progress arrests and even reverses declining finding rates in some regions. As a result, natural gas production is increased, with less drilling activity and at lower cost, particularly in offshore regions, where technological progress has a greater impact on the development of relatively immature fields. In addition, competition within the industry and projections of lower interest rates reduce the costs of transmission and distribution, offsetting the projected increase in wellhead prices, so that the average delivered price of natural gas declines between 1995 and 2015 at an average rate of 0.2 percent.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015 (1995 dollars per thousand cubic feet)



Coal minemouth prices are projected to decline in the forecast as a result of increasing productivity, a shift to western production, and competitive pressures on labor costs. In *AEO97*, the average minemouth price of coal is projected to be $15.46 per ton in 2015 (Figure 7). Lower coal transportation rates--leading to higher production from western mines, where production costs are lower than in the East--are the primary reason for the lower minemouth prices.

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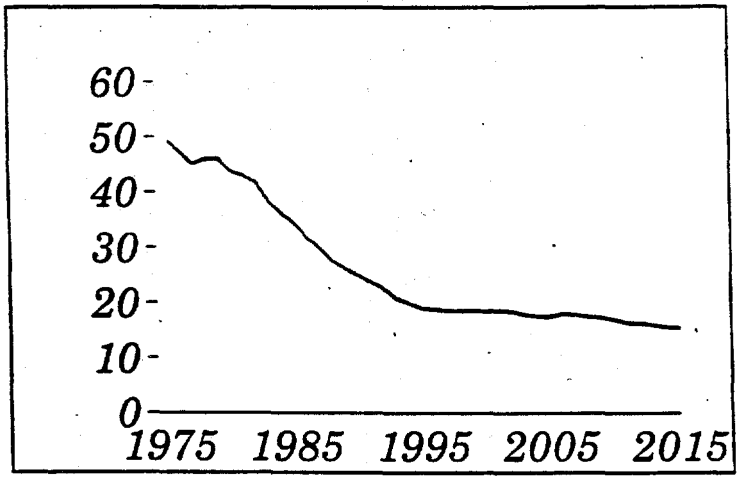
[1]The Electricity Market Module allows the representation of two coal technologies. The IGCC technology was used as representative of an advanced coal technology.

Figure 7. Coal Minemouth Price Projections, 1995-2015 (1995 dollars) (Dollars per ton)



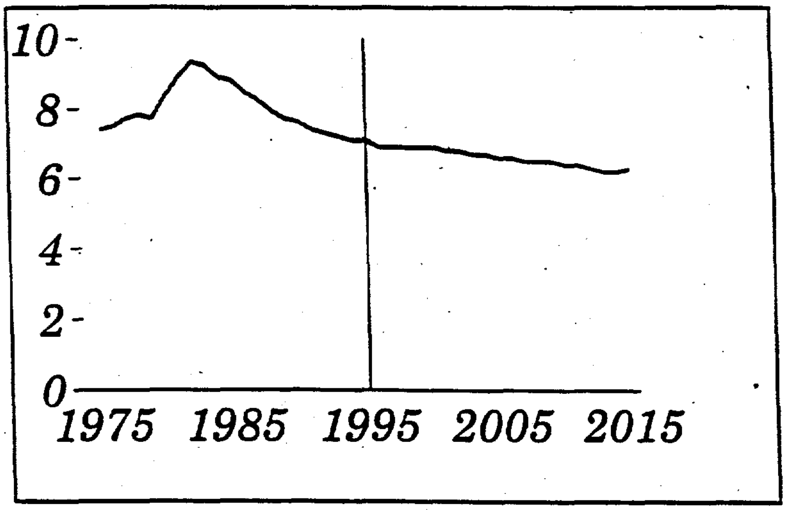
The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates, but fuel efficiency also grows with other productivity improvements in the forecast. As a result, average coal transportation rates decline by 0.9 percent a year between 1995 and 2015. The most rapid declines are likely to occur in routes that originate in coalfields with the greatest production growth. Railroads are likely to reinvest profits from increasing coal traffic to reduce future costs and rates in regions with the best outlook. Thus, coalfields that are most successful at improving productivity and, therefore, lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Regional differences in production and transportation costs are already affecting coal distribution patterns. Western coal is gaining share in midwestern and southeastern markets, and coal for export is moving along different domestic routes. Retirements of barge capacity have exceeded replacements in recent years, and the resulting increase in inland barge rates has caused some traffic to shift to rail or Great Lakes vessels for all or part of the journey from mines to U.S. ports of exit. In spite of railroad mergers and consolidation in the barge industry, real coal transportation costs are projected to continue their historical decline, as competition among surviving carriers forces technological improvements.

Average electricity prices also decline through 2015. The average price in 2015 is projected to be 6.3 cents per kilowatt hour, as a result of lower projected fossil fuel prices and anticipated industry restructuring (Figure 8). Increased competition in the electricity industry is assumed to lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient units, and other cost reductions. The *AEO97* assumes that operating and

maintenance expenses decline by 2.5 percent annually from 1997 to 2007, continuing the trend of the previous 10-year period. Also, expenses charged to general and administrative functions (billing, salaries, and benefits) are assumed to drop by 25 percent during the same period as generators position themselves for increased competition. *AEO97* reflects the evolving trend of competition within electricity markets but does not include the full impacts of restructuring and deregulation. Although the projections include the recent actions taken by the Federal Energy Regulatory Commission on open access, specific actions to be taken by State public utility commissions and their timing are not yet known and have not been incorporated.

Figure 8. Electricity Price Projections, 1995-2015 (1995 dollars) (Cents per kilowatt hour)



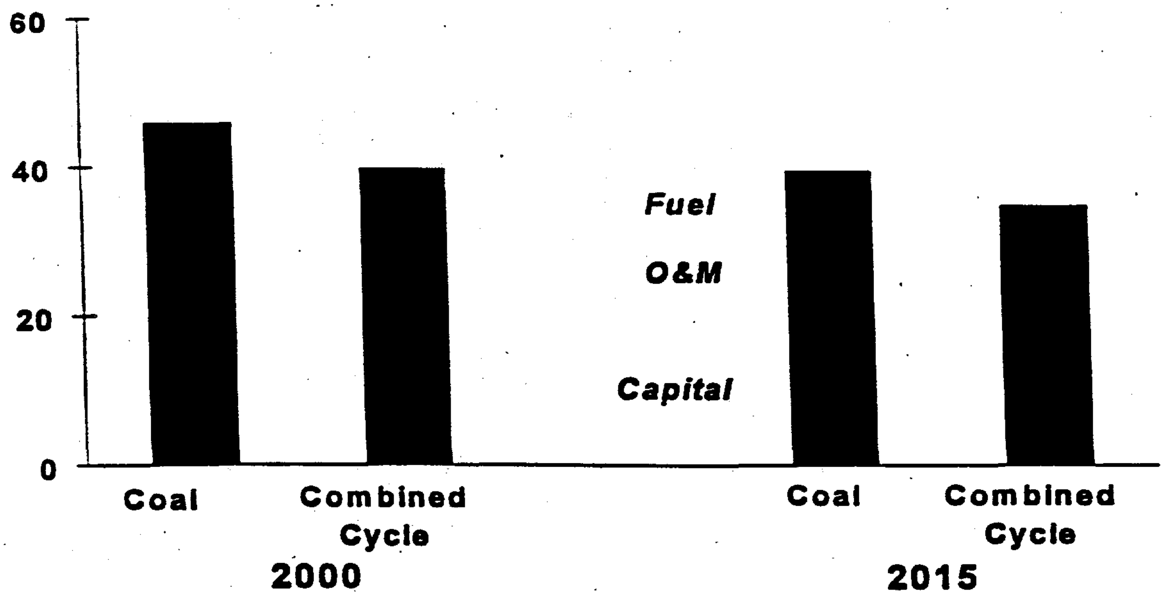
III. Economics of Coal versus Gas Technologies

The expected increasing reliance on gas-fired plants is driven by their economic competitiveness relative to other generating options. Over the last decade technological innovations in natural gas recovery and combustion have combined to lower expectations of future natural gas prices and dramatically increase the combustion efficiency of new gas plants. The result is that gas-fired plants are currently the economical choice for most applications. Figure 9 and Table 1 show the component costs of producing power from a pulverized coal plant and an advanced gas-fired combined cycle plant.[2] As shown the two technologies differ significantly in what drives their total levelized costs. Total coal plant costs are dominated by their capital costs while gas-fired combined-cycle plant total costs are dominated by fuel costs. Overall 55 to 60 percent of a coal plant total costs are related to its construction costs, while 62 to 68 percent of a gas combined-cycle plants costs are accounted for by fuel expenses.

Table 1. Costs of Producing Electricity From New Plants, 2000 and 2015

[2]The figures shown are nationwide averages. In some regions coal is more competitive while in others it is less competitive.

Figure 9. Levelized Cost of Electricity, 2000 and 2015 (Mills per Kilowatthour)



	2000	2000	2015	2015
	Conventional Pulverized Coal	Advanced Combined-Cycle	Conventional Pulverized Coal	Advanced Combined-Cycle
	1995 mills per kilowatt hour			
Capital	25.3	10.6	23.5	6.9
O&M	5.6	4.4	5.6	4.4
Fuel	14.9	24.8	10.3	23.4
Total	**45.8**	**39.9**	**39.4**	**34.5**
	Btu per kilowatt hour			
Heatrate	9,928	6,985	9,463	5,700

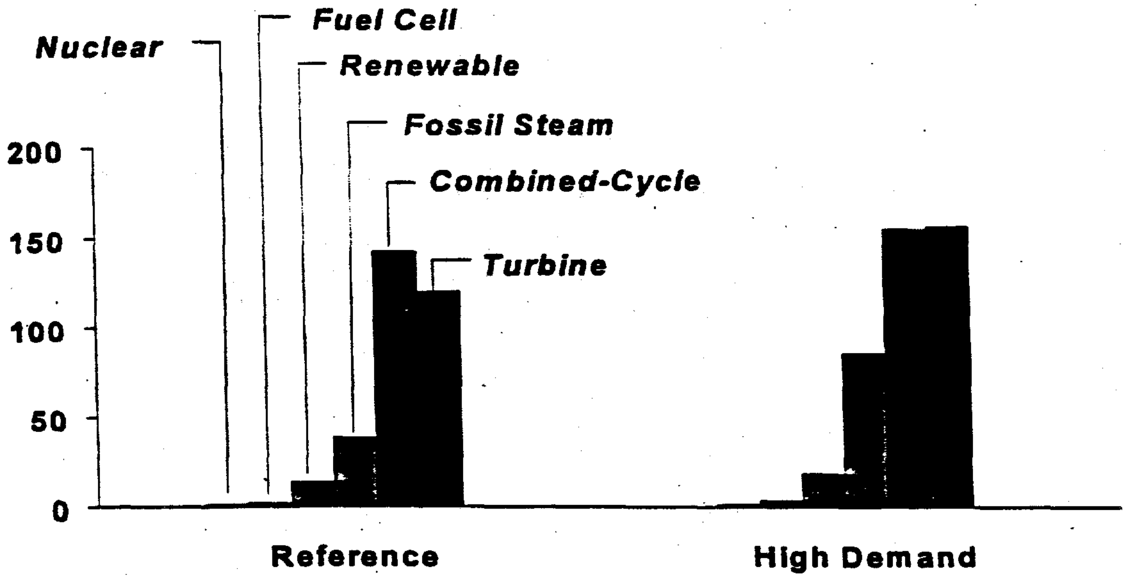
IV. Uncertainties and Impacts of Electricity Market Restructuring

Among the uncertainties with respect to the size of the market for new coal powerplant technologies are the rate of growth of the demand for electricity, the prices of competing fuels, especially natural gas and the rate of technological innovation (improvements in the cost and performance of advanced generating technologies). The restructuring of the electricity market could also have a significant impact, but its impact would affect the demand for electricity and fuel prices. While the rate of growth in the demand for electricity has slowed over the last 30 years, over the last 15 years it has averaged 2.4 percent per year. It is expected that the long-term slowing will continue, but it is possible that new electricity uses, tomorrow's VCRs, fax machines, and computers, will continue to evolve and maintain the rate of growth seen in recent years. To test the sensitivity of the results to higher electricity demand growth a case was prepared assuming a rate of growth in the demand for electricity of 2.0 percent annually, much higher than the 1.5 percent annual growth rate in the reference case. The impact on the need for new capacity is large, over 100 gigawatts of capacity beyond that required in the reference case is brought on line (Figure 10). The higher demand growth increases the market for all capacity types, but coal plants gain the most. Between the reference case and the high demand case the amount of new coal plants added more than doubles, reaching a cumulative total of over 80 gigawatts between 1995 and 2015. The reasons for this are twofold. First, the higher demand level increases the total need for new capacity. And, second, the higher demand level has a stronger impact on natural gas prices than it does on coal prices making new coal plants relatively more economically attractive.

If, as many expect, the restructuring of U.S. electricity markets results in lower electricity prices the demand for electricity is likely to be somewhat higher, though how much is unclear. However, this may not result in increased needs for capacity. The need for capacity is determined by the highest demand for electricity occurring during a given period, the so called peak demand. Prices during these supply constrained time periods may actually be much higher in a restructured electricity market than they are today and consumers may respond by reducing their consumption during these time periods while increasing it in lower cost time periods. The net result of this shifting demand could be increasing utilization of existing lower cost facilities, but a reduction in the need for new capacity for some time.

Two additional cases were prepared to assess the sensitivity of the results to the rate of technological improvement. In the reference case, higher initial capital costs are assumed for new, advanced generating facilities, to account for both technological optimism and inexperience in constructing the new designs. The costs are assumed to decline as a function of market penetration. To examine the effects of these assumptions, a high technology case was developed, with capital cost reductions due to learning effects assumed to be 50 percent greater than in the reference case, and optimism factors (which increase the cost of the earliest units constructed) assumed to be 50 percent lower than in the reference case. These assumptions result in costs for advanced technologies being approximately 12 percent lower than in the reference case. A low technology case was also prepared assuming that only those technologies available (beyond the initial testing and pilot program phase) as of 1996 are permitted to compete. The most

Figure 10. New Generating Capacity by Fuel Type in Two Demand Cases, 1995-2015 (Gigawatts)



significant result between the low and high technology cases is the shift from conventional gas-fired technologies to advanced gas-fired technologies (Figure 11). Advanced coal and renewables plants only penetrate by small amounts.

Two alternative *AEO97* analyses--the high and low nuclear cases--show how changing assumptions about the operating lifetimes of nuclear plants affect the reference case forecast of nuclear and fossil capacity. The low nuclear case assumes that, on average, all units are retired 10 years before the end of their 40-year license periods (93 units by 2015). Early shutdowns could be caused by unfavorable economics, waste disposal problems, or physical degradation of the units. The high nuclear case assumes 10 additional years of operation for each unit (only 4 units retired by 2015), suggesting that license renewals would be permitted. Conditions favoring that outcome could include continued performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities. In the low nuclear case, more than 100 new fossil-fueled units (assuming an average unit size of 300 megawatts) would be built to replace retiring nuclear units. The new capacity would be split mainly between coal-fired (37 percent) and combined-cycle (47 percent) units. The additional fossil-fueled capacity would produce 43 million metric tons of carbon emissions above those in the *AEO97* reference case, in 2015 (1,799 million metric tons total, 678 million metric tons from electric generators). Also, 3 gigawatts of additional new renewable and fuel cell capacity would be built. In the high nuclear case, 32 gigawatts of new capacity additions--mostly fossil-fueled plants--are avoided, as compared with those in the *AEO97* reference case, and carbon emissions are reduced by 29 million metric tons (4 percent of total emissions by electricity generators).

Figure 11. Unplanned Capacity Additions in Three Technology Cases, 1995-2015 (Gigawatts)

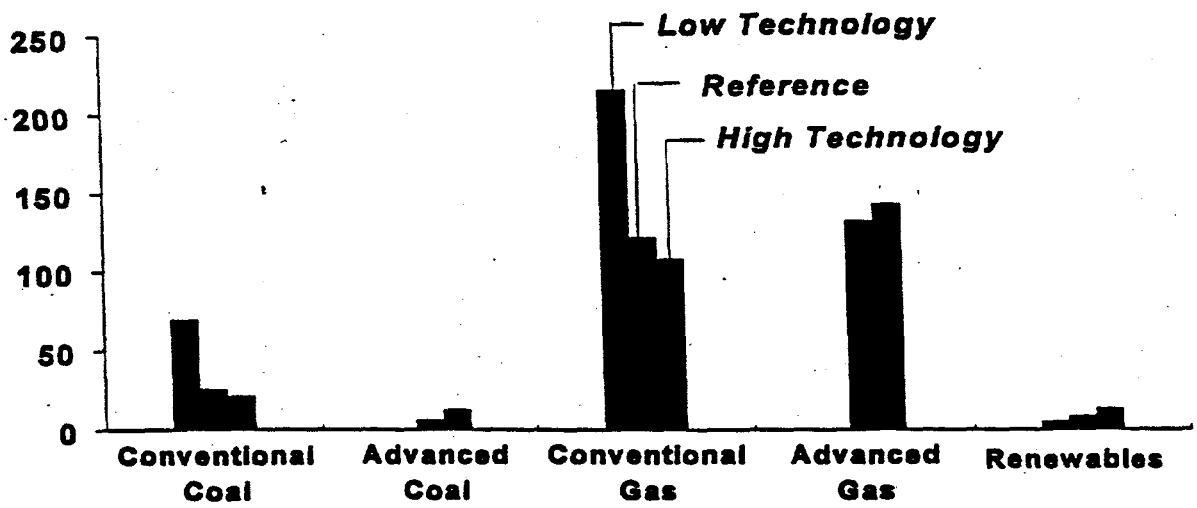
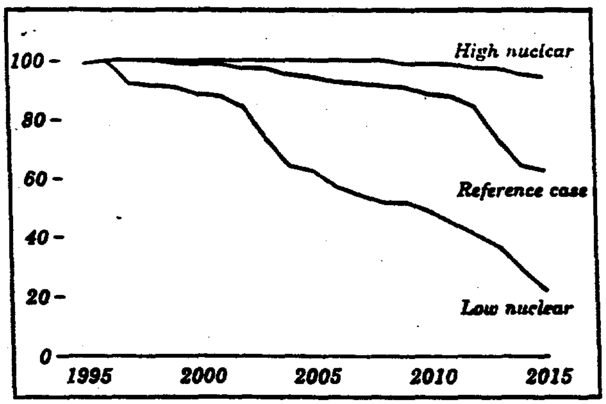


Figure 12. Operable Nuclear Capacity in Three Nuclear Cases, 1995-2015 (Gigawatts)



V. Conclusions

Over the next 10 to 20 years natural gas-fired generation technologies are expected to meet most of the needs for new capacity. Their relatively low capital costs, high thermal efficiencies and low emissions rates make them very attractive. New coal fired technologies are expected to account for around 11 percent of new capacity added, though that number could be larger if the demand for electricity or natural gas prices prove higher than expected. The major market of new clean coal technologies in the U.S. may be in retrofitting or repowering existing plants to meet new environmental requirements.

Figure Notes

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A8 and A20.

Figure 2. Annual Electricity Sales by Sector, 1970-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Table A8.

Figure 3. New Generating Capacity and Retirements, 1990-2015
Annual Energy Outlook 1997, Table A9.

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995-2015
Annual Energy Outlook 1997, Table A9.

Figure 5. Fuel Prices to Electricity Suppliers and Electricity Prices
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A3 and A8.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015
Annual Energy Outlook 1997, Table A1.

Figure 7. Coal Minemouth Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A1.

Figure 8. Electricity Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A8.

Figure 9. Levelized Cost of Electricity, 2000 and 2015
Annual Energy Outlook 1997, National Energy Modeling System, run AEO97B.D100296K.

Figure 10. New Generating Capacity by Fuel Type in Two Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and F6.

Figure 11. Unplanned Capacity Additions in Three Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and B9.

Figure 12. Operable Nuclear Capacity in Three Cases, 1995-2015
Annual Energy Outlook 1997, Table F5.

An Analysis of Cost Effective Incentives for Initial Commercial Deployment of Advanced Clean Coal Technologies

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This analysis evaluates the incentives necessary to introduce commercial scale Advanced Clean Coal Technolgies, specifically Integrated Coal Gasification Combined Cycle (ICGCC) and Pressurized Fluidized Bed Combustion (PFBC) powerplants. The incentives required to support the initial introduction of these systems are based on competitive busbar electricity costs with natural gas fired combined cycle powerplants, in baseload service.

A federal government price guarantee program for up to 10 Advanced Clean Coal Technology powerplants, 5 each ICGCC and PFPC systems is recommended in order to establish the commercial viability of these systems by 2010. By utilizing a decreasing incentives approach as the technologies mature (plants 1-5 of each type), and considering the additional federal government benefits of these plants versus natural gas fired combined cycle powerplants, federal government net financial exposure is minimized. Annual net incentive outlays of approximately 150 million annually over a 20 year period would be necessary. Based on increased demand for Advanced Clean Coal Technologies beyond 2010, the federal government would be revenue neutral within 10 years of the incentives program completion.

I. INTRODUCTION AND BACKGROUND

Over the last 20 years, numerous financial incentives studies have been performed with the aim of assisting new energy systems in their early commercial introduction into the electric power and other energy sectors. These studies have focused on: a) financial support or incentives for production of fuels e.g. oil, gas, and coal, b) introduction of new power systems e.g. nuclear power, c) synthetic fuels production from domestic resources, and d) incentives for the introduction of early commercial Advanced Clean Coal Technologies.

With the strong awareness of the need to minimize further federal funding for Clean Coal Technologies, the U.S. DOE Fossil Energy Office requested that a thorough review be made of the most pertinent incentives studies and recommendations be developed for their further consideration. Emphasis was placed on developing a federal incentives approach which would be tax revenue neutral to the federal government i.e. the public taxpayer, at least within a meaningful planning horizon.

Within this context, a critical analysis was initiated of these previous studies, and specific incentives were estimated to enhance the early commercial introduction of Advanced Clean Coal Technologies (ACCTS) such as Integrated Coal Gasification Combined Cycle (ICGCC) power systems and Pressurized Fluidized Bed Combustion (PFBC) powerplants.

II. OBJECTIVES OF THE ANALYSIS

The specific objectives of the analysis are to:

* Critically Review Specific Previous Incentives Studies.

* Identify Incentives Which Balance Risk Among Stakeholders/ Minimize Federal Expenditures.

* Develop a Federal Tax Based Revenue Neutral Advanced Clean Coal Technology Commercial Deployment Approach.

* Recommend Specific Options for Further In Depth Analysis and Consideration by the U.S. Department of Energy, Fossil Energy Office.

All of these objectives have been specifically addressed and met within the scope of this analysis.

III. PERSPECTIVE ON PREVIOUS FEDERAL INCENTIVES FOR DOMESTIC FUELS AND COMMERCIAL DEPLOYMENT OF POWER TECHNOLOGIES

In order to place the incentives necessary for initial commercial Advanced Clean Coal Technologies in proper perspective, a brief review of previous federal incentives used to stimulate fuels/energy production was conducted.

A study conducted for the U.S. DOE by Battelle Pacific Northwest Laboratory, "A Analysis of Federal Incentives Used to Stimulate Energy Production", Reference 1, provided an excellent perspective basis. Although the report was prepared in 1980, and should be updated, it provides an interesting perspective on U.S. federal incentives for various fuels and energy systems.

Table I summarizes the federal incentives provided for various energy sources in the period 1950 to 1978 in billions of 1978 dollars. Of course, since many of these incentives are "running" i.e. currently in place, the total incentives would be substantially greater today. In fact, it is recommended that this analysis be updated to a current basis.

However, it is clear from Table I that a) the federal government has provided substantial tax and other incentives for producing fuels, energy, and electricity in the past, in fact over 250 billion dollars thru 1978, b) production of oil has received the most favorable tax treatments by the federal government, tax

Table 1

Federal Incentives Used to Stimulate
Energy Production (1950-1978) in Billions of 1978$

Energy Source	Estimated Amount	Type of Incentive
Nuclear	21.0	R/D/D, Enrichment Plants
Hydro	16.9	Producing/Marketing Power
Oil	123.6	Tax Deductions (IDC, D.A.)*
Natural Gas	14.6	Reduced Taxes (IDC, D.A.)*
Electricity	64.5	Public Utility Debt Subsidy
Coal	11.7	Water Borne Movement of Coal, Tax Incentives, R/D/D

* I.D.C. - Intangible Drilling Costs; D.A.- Depletion Allowance

incentives being nearly 10 times those for either natural gas or coal, and c) electricity production subsidization has previously primarily benefitted nuclear power and public utility entities such as the rural electric co-operatives and federal power programs.

It would appear that a federal government financial incentives program, building on the 7.1 billion dollar industry/federal government partnership in the Clean Coal Technology Program, would be warranted, in relation to federal incentives, which have been provided for other fuels and power sources.

This analysis will focus on defining a minimum federal outlay incentive program to stimulate commercialization of Advanced Clean Coal Technologies, namely Integrated Coal Gasification Combined Cycle (ICGCC) and Pressurized Fluidized Bed Combustion (PFBC) power systems and to develop a perspective on the projected costs of power from these systems, compared to natural gas fired systems.

IV. SUMMARY OF PREVIOUS INCENTIVE STUDIES

The key results from each of 8 previous incentives studies which impacted directly on the approach taken in this analysis include:

* Use of highly leveraged financing to minimize capital return requirements; thus cost of capital.

* Deferred income taxes from the FOAK plants.

* Emphasis on performance based incentives, as contrasted to capital subsidization.

* Clear need for "benchmark" technology performance and electricity cost for defining electricity price parity incentive requirements.

* The need for adequate financial rewards for risk taking of First-of-a-Kind (FOAK) and early commercial plants.

* The importance of a federal government role in overcoming high financial costs of early ACCT plants.

* Importance of balancing financial risks among all stakeholders i.e. the power produces, ratepayers, the federal government, taxpayers, and state governments.

* Any federal incentives to assist the introduction of ACCT's should have a decreasing incentive basis as later units of a particular technology type are deployed. Federal government incentives should be utilized to both assist and force the technologies to achieve mature status after the first 4 or 5 units of each advanced

plant type are deployed.

* Decreasing incentives with deployments of later versions of each plant type should be in both magnitude of the incentive and duration of financial support.

* The benchmark technology against which ACCT's should be compared should be Natural Gas Fired Combined Cycle (NGCC) powerplants. Meaningful real natural gas price escalations should be used to clearly identify the incentives required, particularly for the first five plants of each ACCT. A range of fuel price escalation scenarios should be used to demonstrate the uncertainties surrounding premium fossil fuel i.e. natural gas price projections.

* Care should be taken in defining incentives which do not result in a "windfall" profit to the power generator shareholders at the expense of the federal government, taxpayers, or at the expense of the ratepayers of the specific utility producing or purchasing the power.

* Differential tax revenues between NGCC powerplants and ACCT plants may be an effective way of reducing the full incentive burden on the federal government.

V. DETAILED INCENTIVE ANALYSIS

As was discussed above, the necessary financial incentives will be defined by comparing "benchmark" electricity costs from NGCC plants relative to those from ACCT's. In order to define a clear basis for the financial incentives necessary to bring ACCT's into electricity price parity with NGCC powerplants, financial, performance, and cost bases for each plant type must be defined. Those bases are summarized in Table 2 for powerplant capacities of 500 Mwe and an annual capacity factor of 0.65.

A. Natural Gas Fired Combined Cycle Powerplants

Because of the significance of projected natural gas prices, three cases were evaluated, namely:

* EIA-96 Reference Gas Case (Reference 2)

  * $2.41 per million Btu (96$ in 2005), escalated from $2.31 per million Btu in 94$, with a long term real price escalation rate of 1.4% per annum (Case 1).

  * $2.55 per million Btu (96$ in 2005), escalated from $2.44 per million Btu in 94$, with a long term escalation rate of 2.7% per annum (High Economic Growth - Case 2).

Table 2

Financial Analysis Bases for Incentives Comparison

Parameter/Units	Range of Value Considered	Value(s) Adopted
Levelized Current Dollar Fixed Charge Rate	0.106 to 0.16	0.144
Natural Gas Fired Combined Cycle Powerplants		
* Plant Capacity, Mwe	500	500
* Capital Cost, $/kwe(96$)	600-700	600
* Annualized Heat Rate, HHV Btu/Kwhr	6000-6800	6000
* Natural Gas Prices/Real Price Escalation Rates, $\$/10^6$ Btu, %	2.41-3.36[1] 1.4-5.0%	2.41, 1.4% (Case 1) 2.55, 2.7% (Case 2) 3.36, 5.0% (Case 3)
* O&M Costs, mills/kwhr	4	4
* Annualized Capacity Factor	0.65	0.65
* Levelized Current Dollar Cost of Electricity, cents/kwhr		3.83 (Case 1) 4.11 (Case 2) 5.40 (Case 3)

(1) Prices are 1996$ in 2005, starting date for the comparative analysis

Table 2 (Cont'd)

Financial Analysis Bases for Incentive Comparison

Parameter/Units	Range of Value Considered	Value(s) Adopted
Advanced Clean Coal Technologies (ICGCC & PFBC)		
* Plant Capacity, Mwe	500	500
* Capital Costs, $/Kwe (1996$)	1100-1500[1]	1500 (Case 1) 1300 (Case 2) 1100 (Case 3)
* Annualized Heat Rate, HHV, Btu/Kwhr	6800-8400	8400 (Case 1) 7800 (Case 2) 6800 (Case 3)
* Coal Prices, $\$/10^6$ Btu,	0.87-1.17	0.87
Escalation Rate, %	1.4%	1.4%
* O&M Costs, mills/kwhr	6-8	7
* Annualized Capacity Factor	0.65	0.65
* Levelized Current Dollar Cost of Electricity, cents/kwhr		5.45 (Case 1) 4.87 (Case 2) 4.26 (Case 3)

(1) Prices are 1996$ in 2005, starting date for comparative analysis.

* High Gas Demand Coupled with High World Oil Prices (Extension of EIA Forecasts)

    * $3.36 per million Btu (96$ in 2005), with a long term real price escalation rate of 5% per annum (High Economic Growth Escalation Rates from EIA 96 in 2010-2015 - Case 3).

These natural gas prices/escalation rates result in levelized current dollar costs of electricity from baseload natural gas fired powerplants of 3.83, 4.11, and 5.40 cents per kwhr, using a 1996 dollars initial basis in 2005, as shown in Table 2, and a 2.5% per annum average inflation rate beyond 2005.

B. Advanced Clean Coal Powerplants

The Advanced Clean Coal Technologies, Integrated Coal Gasification Combined Cycle (ICGCC) and Pressurized Fluidized Bed Combustion (PFBC) powerplant performance is also shown in Table 2. There may be some differences in the performance of each of these systems; however for purposes of this analysis, the same performance is used for both systems, as they mature.

Three cases are also considered for these 2 ACCT's, but they represent both potential capital cost reductions/performance improvements as the technologies are deployed and reach mature commercial plant status. The three cases are:

* First-of-a-Kind Plants: First 2-500 Mwe units of ICGCC and PFBC powerplants - $1500/Kwe, capital costs, and 8400 Btu/Kwhr, annualized heat rate (Case 1).

* Enhanced Plants: Plants 3 and 4 of each ACCT plant type - $1300/Kwe, capital cost, and 7800 Btu/Kwhr, annualized heat rate (Case 2).

* Mature Commercial Units: Plants 5 and beyond, $1100/Kwe, capital costs and 6800 Btu/Kwhr, annualized heat rate (Case 3).

All costs are in 1996 dollars.

Although coal costs will clearly vary with location, a 1996 high sulfur coal cost of 87 cents per million Btu was adopted, with a real price escalation rate of 1.4% per annum. These costs result in levelized current dollar costs of electricity of 5.45, 4.87, and 4.26 cents per kwhr, respectivley. It is recognized that Case 3 is a stretch goal, but is consistent with a 30% learning curve capital cost reduction from today's costs of approximately $1500 to $1700/kwe for the 250 Mwe Clean Coal Technology/Demonstration Projects. (Reference 3)

C. Projected Incentives to Produce Levelized Electricity Price Parity

These costs can now be compared for each of the three natural gas price scenarios and the three ACCT cost/performance improvement projections. This comparison is shown in Table 3, wherein the differential current dollar levelized cost of electricity is shown in a three by three matrix. It is clear that significant financial incentives are necessary to bring early First-of-a-Kind (FOAK) ACCT plants into price parity with NGCC powerplants. Specifically, the electricity price differentials initially would be approximately 1.62 cents per kwhr for FOAK plants. As the ACCT's mature and projected gas prices escalate, the ACCT's should become competitive; however if natural gas prices escalate only moderately,,i.e. at less than 2% real per annum, the ACCT systems will not become competitive, even with mature costs and performance.

VI. RECOMMENDED ELECTRICITY PRICE INCENTIVES APPROACH

A. Application to ICGCC and PFBC, Initial Plants

Table 3 provides a basis for defining a federal incentives program to stimulate commercialization of ICGCC and PFBC systems. The required incentives would result in price parity between ACCT's and NGCC plants. As may be seen from Table 2 and 3, early FOAK plant price subsidies of 1.62 cents per kwhr would be necessary. This represents approximately a 30% price support level for FOAK plants, for each ACCT system.

As discussed above, this incentive provides levelized electricity price parity between NGCC and FOAK ACCT's over their 30 year electricity production periods. As both engineering design experience and field data are obtained, this incentive should be decreased. The key problem is that in a rapid deployment period, say 2005 to 2010, only limited new operating experience will be available between each of the first 2 ICGCC and PFBC powerplants at a 500 Mwe capacity. This would argue for a full 30 year price guarantee, for each plant. However, in discussions held with regulated utility and independent power producers (IPP's), during a preliminary review of this study, they recommened that the first plants of each type receive a 20 year price guarantee incentive. This also provides some risk sharing between the federal government and the power producer.

As some engineering experience is gained, capital costs decrease, and performance improves, plants 3 and 4 of each type should receive a lesser incentive. From Table 3, it appears that a 20 year price incentive of 1.04 cents per kwhr might be adequate for plants 3, and 0.76 cents per kwhr for 15 years for plant 4. Plant 5 might receive a small incentive of 0.5 cents per kwhr for

Table 3

Differential Levelized Cost of Electricity
Comparison Between Advanced Clean Coal Technology[1,2]
Powerplants With Natural Gas Fired Combined Cycle Systems
(¢/Kwhr)

NGCC Systems	ACCT Systems	1st & 2nd of Kind Plants	3rd & 4th of Kind Plants	Mature Plants
Case 1, EIA96 Low Gas Price Growth		1.62	1.04	0.43
Case 2, EIA96 Mod. Gas Price Growth		1.34	0.76	0.15
Case 3, EIA96 High Gas Price Growth		0.05	(0.53)	(1.14)

(1) ACCT's Are ICGCC and PFBC in This Analysis

(2) Bases Are Initial Costs in 1996$ for Plants Starting Up In 2005-2010

10 years, if natural gas prices remain low or none if gas prices escalate rapidly.

This incentive approach, along with the estimated total incentive required, is summarized in Table 4. The total incentive amount would be approximately 5.42 billion dollars for the first 5 ICGCC and PFBC plants.

Although this is a significant amount, part of this incentive would be made up from the higher federal taxes which would be produced from the ACCT's, compared with NGCC powerplants. (See Following Analysis)

B. Potential Financial Risk to the Federal Government

As shown in Table 4, the total potential financial exposure to the federal government of the recommended incentives program for ACCT's is estimated to be 5.42 billion dollars. However, the capital intensive nature of the ACCT's will produce significantly greater tax revenues than from NGCC powerplants.

An estimate of the federal income tax from each of the first 2 ICGCC and PFBC plants in their first 20 years of operation is approximately 450 million dollars, compared with approximately 180 million dollars for an NGCC powerplant. This produces a net tax benefit to the federal government of 270 million dollars per plant. Similarly, plants 3 and 4 of each type produce a net tax benefit of approximately 210 million dollars, each, in their first 20 years of operation. Plant 5 of each type would have a projected net tax benefit of 150 million dollars.

The implications of these tax benefits are shown in Table 5. The incremental tax benefits are projected to be 2.22 billion dollars for the first five ICGCC and PFBC powerplants, which is approximately 40% of the recommended federal incentives amount. Thus, the net incentive to the federal government is reduced to 3.20 billion dollars. These costs are on a current dollar basis since the levelized cost of electricity is on a current dollar basis, but represent a current dollar amount based on initial dollars being 1996$.

If this incentive is distributed as a price guarantee over approximately a 25 year period, i.e. plants coming on line from 2005 to 2010, net annual expenditures for such a program are approximately 130 million dollars per year. This would appear to be a very low cost to insure that Advanced Clean Coal Technologies are fully commercial and ready for deployment, should natural gas prices begin to escalate rapidly.

In fact, if natural gas price projections change dramatically beyond 2005, the federal government might negotiate a lesser price guarantee for the out years of any price guarantee agreements, since the ACCT's would be producing competitively

Table 4

Recommended Declining Incentive Approach
Electricity Price Guarantee to IPP or
Regulated Utility

Initial Commercial Plants[1]	Incentive Amount ¢/Kwhr	Duration Years	Total Incentive Amount (Billions of $)	Rationale
First	1.62	20	1.84	Low Gas Esc. High Coal Plant Cost
Second	1.34	20	1.52	Mod. Gas Esc., High Coal Plant Cost
Third	1.04	20	1.18	Low Gas Esc., Imp. Coal Plant Cost
Fourth	0.76	15	0.64	Mod. Gas Esc., Imp. Coal Plant Cost
Fifth	0.43	10	0.24	Low Gas Esc., Mature Coal Plant Cost
		Total	5.42	

(1) Each Plant Type - ICGCC or PFBC

Table 5

Net Federal Incentive Analysis for
Advanced Clean Coal Technology Commercialization
(Billion of $)

Initial Commercial Plants[1]	Total Federal Incentive	Incremental Tax Income[2]	Net Incentive
First	1.84	0.54	1.30
Second	1.52	0.54	0.98
Third	1.18	0.42	0.76
Fourth	0.64	0.42	0.22
Fifth	0.24	0.30	-0.06
	5.42	2.22	3.20

(1) One ICGCC and One PFBC Per Incentive

(2) Incremental Federal Tax - Advanced Coal Vs NGCC

priced electricity, and with their low heat rates, would be preferentially dispatched.

One note of caution. This analysis did not consider the additional taxes which may be derived from the natural gas sales to the NGCC plants compared to sales of coal to the ACCT's. This should be considered in more detail in order to determine if this would have any significant effect on the differential tax revenues.

C. Federal Government Revenue Neutral Estimates

The federal incentive program recommended above results in a net incentive requirement from the federal government of approximately 3.2 billion dollars. One of the objectives of this analysis is to define a revenue neutral basis for the federal government. This does not appear to be possible within the context of deployment of the first 5 plants of each ACCT.

However, once these technologies have matured and become the technology of choice for future baseload capacity, there will be a continuing stream of net tax revenues flowing to the federal government. This increased tax revenue over Natural Gas Fired Combined Cycle powerplants will begin to offset the net incentive costs to the government during the 20 year price guarantee period.

If we assume that mature plant capital costs are 1100 dollars per kwe, each plant has a net tax benefit of 150 million dollars, as discussed previously. Thus, the deployment of approximately 21 plants, or 10,500 Mwe of capacity, would make the federal government revenue neutral. If this capacity is added in the 2010 to 2015 time frame, when new coal plant additions are expected to be required (Reference 4), the federal government would be revenue neutral in less than 10 years from the completion of the incentives program outlays, and perhaps sooner. However, since tax revenues from commercial units are being acquired in parallel with the incentive outlays, the federal government only has a 10 year net outlay period, and total net exposure of $1.0 billion.

The above situation most likely represents a worst case situation. For example, if nuclear powerplant retirements should accelerate the need for Advanced Clean Coal Technologies, the federal government would be revenue neutral on a shorter time frame. In addition, if ACCT's have capital costs greater than 1100 dollars per kwe, less plants are necessary to make the federal government revenue neutral. Since plant capital costs in 2010-2015 dollars may be substantially higher than the 1100 dollars per kwe mature plant cost projections, this will also shorten the time to achieve a revenue neutral situation.

Thus, in summary, a federal government incentives program to accelerate and insure commercialization of ICGCC and PFBC advanced coal powerplant technologies would support approximately 4000-5000 Mwe of initial capacity additions for 3.2 billion dollars. Within 10 years of the completion of the outlay program, the federal governments' outlays would be compensated with the addition of approximately 10,000 Mwe of advanced coal capacity. If a greater number of commercial ACCT's are deployed rapidly, these plants would generate additional net tax revenues which would decrease the time period to achieve a revenue neutral situation. This seems like an extremely prudent program for the federal government to support, with minimal financial risk, to assure commercialization of Advanced Clean Coal Technologies.

VII. SUMMARY OF RESULTS/BENEFITS

This incentives analysis provides a basis for the federal government to develop and implement a program to accelerate and insure commercial availability of Advanced Clean Coal Technologies, namely ICGCC and PFBC power systems. If this program were oriented towards deployment of 500 Mwe scale plants in the 2003-2010 time period, these Advanced Clean Coal Technologies would be mature technologies by 2010.

The recommended program of an electricity price guarantee for approximately 20 years would stimulate regulated utilities and independent power producers to commit resources to these technologies. The use of an electricity price guarantee to provide parity with NGCC powerplants would "level" the playing field for early commercial units and establish the performance and operability of ICGCC and PFBC systems.

A price guarantee approach provides a major incentive for the power generator to achieve cost and performance targets, as well as high plant availability/operability. It places the risk of managing capital and operations and maintenance costs on the power producer; thus sharing the risks in these plants. Graduated price supports for the first 5 commercial scale ICGCC and PFBC plants produces an incentive for risk taking on the First-of-a-Kind plants which should attract regulated utility or independent power producers to commit to these technologies.

This approach does not produce a large front end financial burden on the federal government since it is a "running" incentive, rather than a front end incentive. The estimated federal government net obligation of 3.2 billion dollars is outlayed over a 20 year period; therefore annual costs are approximately 150 million dollars. This is a level well within the federal government's previous financial support levels for various advanced power technologies. The federal government recoups all of its net incentive outlays within 10 years of program completions, as the Advanced Clean Coal Technologies are deployed to meet future power demands, and its actual net exposure, including the tax revenues from the commercial ACCT's, is approximately $1.0 billion. Further, this approach will enhance the use of high sulfur eastern coals, and help to maintain electricity prices stable by broadening the acceptable coal sulfur content base.

If natural gas prices escalate more rapidly than projected by the DOE-EIA forecasts, the federal government may be able to reduce its financial support obligation. In any case, this program clearly would establish the basis for coal to compete with natural gas in the 2010-2015 time frame, when significant new baseload powerplant additions will be necessitated. In addition, by designing, constructing, and operating these commercial scale ACCT's, these technologies will be solidly established for both domestic and international markets.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Conclusions

The recommended federal government price guarantee program for up to 10 Advanced Clean Coal Technology powerplants, 5 each of Integrated Coal Gasification Combined Cycle and Pressurized Fluidized Bed Combustion systems would establish these technologies commercially by 2010. By utilizing a decreasing incentives approach as the technologies mature, and considering the additional federal government tax benefits of these plants versus natural gas fired combined cycle powerplants, federal government net financial exposure is minimized. The federal government is essentially revenue neutral within 10 years of the outlays and perhaps sooner.

Absent this program, or one comparable to it, natural gas will be the primary, and perhaps, only, new powerplant fuel in the near future. If natural gas prices begin to escalate rapidly due to increased usage for power generation, conventional coal technology, with its low coal to electricity efficiencies, will be the only viable coal alternative.

The proposed approach provides a balanced risk sharing among the federal government, electricity producers, ratepayers, and taxpayers. Further development of this incentives approach should involve the states most likely to benefit from the program. This would provide the state entities, e.g. Public Utility Commissions, the opportunity to offer additional supporting incentives. This should be particularly attractive to high sulfur coal producing states.

This program will complete the effort initiated by the federal government, in association with industry, which provides the technology base i.e. the Clean Coal Technology Program presently underway. This program may also be of strong interest to the United Mine Workers Union, as it will enhance and perhaps significantly expand, the need for deep coal miners.

Finally, this program provides the basis for high efficiency coal power systems, which minimize all emissions, to become major elements of the U.S. and international electric power systems.

Recommendations

It is strongly recommended that:

1. The U.S. DOE Fossil Energy (FE) Office consider initiating this incentives program, or one comparable, to it, in the FY 1997 or FY 1998 DOE Authorization Process. Actual outlays of funds would not occur until after 2000, probably near 2005, but the program initiation would stimulate industry to begin planning full commercial scale ICGCC and PFBC projects.

2. DOE-FE review these results further with a set of representative regulated utility and independent power producer executives to obtain their reactions to such a program. Preliminary discussions with 2 independent power producers and 1 major regulated utility were favorable, but there needs to be further dialogue with them.

3. A dialogue be developed between the U.S. DOE-FE and key states to define additional financial incentives which could be provided by the states to support this program.

4. DOE-FE consider having a more detailed financial analysis of these proposed incentives performed utilizing discounted cash flow utility financing methodolgy. Although this levelized cost of electricity approach should be quite accurate, perhaps a broader range of fuel price forecast and financing approaches should be considered prior to formal program initiation.

5. An examination be made of differential federal income taxes between the use of natural gas for power generation, compared with the use of coal. This analysis should include the following considerations: differences in tax revenues from a) power generation types (to confirm these analysis results), b) fuel sales to the powerplant, and c) personal incomes associated with each plant type.

6. The DOE-FE should also consider updating the Battelle Northwest study to provide a current perspective on incentives provided for other fuel and power systems.

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Acknowledgment

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THE ROLE OF CLEAN COAL TECHNOLOGIES IN A DEREGULATED RURAL UTILITY MARKET

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ABSTRACT

The nation's rural electric cooperatives own a high proportion of coal-fired generation, in excess of 80 percent of their generating capacity. As the electric utility industry moves toward a competitive electricity market, the generation mix for electric cooperatives is expected to change. Distributed generation will likely serve more customer loads than is now the case, and that will lead to an increase in gas-fired generation capacity. But, clean low-cost central station coal-fired capacity is expected to continue to be the primary source of power for growing rural electric cooperatives. Gasification combined cycle could be the lowest cost coal based generation option in this new competitive market if both capital cost and electricity production costs can be further reduced. This paper presents anticipated utility business scenarios for the deregulated future and identifies combined cycle power plant configurations that might prove most competitive.

I. NRECA and RER

NRECA is the national trade association representing the nation's nearly 1000 consumer-owned electric cooperatives. Recognizing the importance of science and technology to the success of its electric cooperative members, NRECA administers a research and development program for its member systems known as the NRECA Rural Electric Research (RER) Program. RER is voluntarily funded by participating member cooperatives at approximately $4.5 million annually. RER works closely with EPRI and other utilities to ensure that industry-wide technology developments may be applied to the unique needs of rural electric systems in a cost-effective manner.

II. UNIQUENESS OF ELECTRIC CO-OPS

Electric cooperatives, for the most part, serve sparsely populated rural and agricultural areas of the U.S., representing some of the nation's least developed and roughest terrain. Even so, co-ops sell about 7.5% of the nation's power to 30 million consumers in 46 states, and own nearly half of the distribution line miles in the country in order to deliver this power to their consumers. Co-ops average about five consumers per mile of line compared to the rest of the electric utility industry's average of around 40 customers per mile. Since electric revenue is a direct function of customer density, providing economical electric services to rural consumers is a challenge. This is complicated by the fact that much of rural electric load growth occurs at the end of long feeders. Thus, expensive transmission and distribution right-of-ways must be acquired in order to upgrade or provide new lines for increased power supply to these locations via conventional central station service.

III. CO-OP POWER SUPPLY TODAY

Currently, nearly one-half of electric cooperative power needs are provided by 60 generation & transmission (G&T) cooperatives. These G&T cooperatives are owned by the distribution cooperatives they serve. From an operational point of view, rural electric generation facilities are not very different from the rest of the utility industry. Where co-ops are different is that they own a high proportion of coal-fired generation, in excess of 80 percent of their generating plant capacity. Co-op generating facilities are environmentally the cleanest in the industry because they are the newest. Forty-four percent of the co-op coal-fired capacity already has flue gas scrubbers compared to 20 percent nationwide. All together, co-ops own or have ownership in 11 of the nation's lowest-cost power producers.

IV. DEREGULATION

NRECA and its member systems have actively participated in the policy deliberations involving deregulation of the nation's electric utility industry. Chief among the possible changes anticipated is the "unbundling" of the services performed by what has historically been a vertically integrated industry. Unbundling proposals could separate the electric utility industry into four distinct components: generation, transmission, distribution and energy services.

Generation Company (GENCO)

The generation part of the business will in all likelyhood compete in an open wholesale market. Restructuring advocates often propose that the generation component of an electric utility's business be sold to an independent company or spun off to a separate unregulated utility affiliate, a GENCO. The power would be sold at whatever price the seller could obtain in the generation market at a given time—known as a *market-based* rate. This means that power rates would not be *cost-based* on what it took to produce the power, but rather only the price the power could command in the marketplace.

Transmission Company (TRANSCO)

Transmission, following the finalization of Federal Energy Regulatory Commission (FERC), Orders Nos. 888 and 889, will be an open access system. Restructuring proposals often call for the transmission component of an electric utility's business to be given to a separate regulated TRANSCO, or even handed off to an "Independent System Operator" (ISO). Most proposals would continue regulation of transmission, on the assumption that it is unlikely for substantial competition to develop in the transmission sector. This is due to the difficulties and high costs of building transmission lines, getting rights of way and obtaining needed environmental and land-use clearances. Since bulk transmission lines often transmit power that comes from other states, plans call for FERC to regulate the price for and terms of transmission services.

Distribution Company (DISCO)

Under many restructuring proposals, the distribution component would be handed by a separate regulated distribution company, called a DISCO. Like transmission, most proposals would continue the regulation of DISCOs, because of the high cost of building duplicate distribution lines, and the aesthetic/environmental constraints. Virtually, all plans call for state regulation of DISCOs.

However, DISCOs would not necessarily perform all of the functions that we currently think of when we think of electric distribution companies. Many proposed DISCOs would carry out a pure *wires* (electricity delivery) function. The actual sale of electricity at retail is generally proposed to be open to competition. Retail customers would pick their electric power supplier just like they now pick their long-distance telephone service provider. This separation of the *wires* functions from the actual sale of the power is the essence of *retail wheeling, retail access,* and *customer choice,* terms we have all heard as part of the restructuring debate. Retail access is at the heart of the restructuring debate. Restructuring advocates want retail customers to be able to purchase their electric power from any one of a number of suppliers, with the power being transmitted and delivered by an entity distinct from the supplier. For the utility that owns the DISCO to compete for actual electricity sales to retail customers, it would have to form its own separate marketing entity, and that entity would have to use the DISCO for delivery service, just like any other supplier.

Energy Service Company (ESCO)

Retail electric distribution service may be split up into a number of parts: *delivery, retail sales,* and *energy services.* Retail sales could be made by generators, marketers, brokers, aggregators of all sorts. The providers and types of energy services are just beginning to emerge. Some envision separate energy service companies (ESCOs) that would become the marketers of a wide-range of services such as purchasing electricity from power producers, repackaging the electricity with valued-added consumer services and seeking out markets in which compete..

V. IMPACT OF DEREGULATION

These potential changes will have a substantial impact on every aspect of the electric utility business. A broadly-based task force drawn from NRECA's membership studied the likely industry changes and recently issued an initial report on the resulting competitive issues. The task force arrived at five conclusions that will receive a great deal of attention from electric cooperatives and may have implications for the entire industry. These are felt to be valid regardless of how the industry finally restructures:

- Customers will have their choice of an energy provider;
- There will be increasing pressure to regulate all distribution operations;
- The future of all power supply arrangements is unclear;
- The advantage of electric co-ops is their strong relationship with consumers;
- Future success requires being competitive on price, service and reliability.

Even though the final industry restructuring is not yet known in detail, one can draw certain general conclusions about the four proposed utility functions that may evolve:

Transmission

This part of the business will be regulated as an open access network by the federal government through FERC. The past decade has seen a four-fold increase in bulk power transfers across the country. Now, 40% of the electricity generated in the U.S. is sold by the producing utility on the bulk power market before it reaches consumers. Such wholesale transactions, which involve electricity transfers over transmission networks, are expected to increase significantly because of federal deregulation producing open access to the networks. Transmission systems, for example, now experience loads at 70% or more of their capacity less than 20% of the time. For distribution systems, the corresponding capacity utilization occurs less than 5% of the time. Thus, there appears to be adequate capacity to handle the increased transactions that might result from deregulation. But technology is expected to be able to accomodate substantially greater power transfer capability over existing systems if needed.

Distribution

This part of the business will likely be regulated by the states. There is a consensus that it does not make sense for multiple wires and service entrances to be installed depending upon who you elect to provide your power. As a result, regulations will be necessary to compensate the one *wires* company delivering power, while preventing monopolistic pricing policies that would be unfair to the customer. While state-level deregulation will give consumers greater choice among electricity providers, at the same time, consumers are increasingly concerned about the power quality. Momentary disturbances that would have gone unnoticed in the past will become a major concern in the future, causing computers and other digital equipment to malfunction (i.e., the "blinking clock syndrome"). As a result, successful DISCOs will be those that deliver high-quality power at low cost and follow it up with excellent customer service.

Energy Services

ESCOs would likely be unregulated entities competing in the marketplace to provide power to customers. ESCOs would be able to buy bulk power and resell it to consumers along with additional services, or provide distributed generation at or near a customer site. In either case, economics will dictate the choice of generation selected by the ESCO for a particular application. Some predict distributed generation to be as much as 30% of new electric generation by 2010. If true, that would be more than 50 gigawatts of the 175 gigawatts of generation growth that the U.S. Energy Information Administration (EIA) expects by then. NRECA believes distributed generation will be a valuable power supply option for servicing many rural customer loads. But, the electric co-ops see a much more modest growth in distributed generation by 2010, probably not exceeding 5 to 10 percent of total generation expansion, if that much.

Generation

Although FERC and others are still working out the details, it appears likely that the generation part of the business may ultimately become totally deregulated and truly compete on the open market to sell the electricity it produces. This power will be sold as a commodity like oil or corn. In fact, electricity futures markets are already being formed in anticipation of the public buying and selling bulk electricity transactions just as is the case with other commodities.

In such a marketplace, only the low-cost providers survive. Unlike ESCOs that will provide distributed generation at a premium cost level of perhaps 4 to 5 cents/kWh or more along with services to solve a customer problem, GENCOs will sell bulk power strictly on the basis of what the market will pay for this commodity. Average power production costs in the U.S. dropped below 2 cents/kwh for the first time since 1981 according to the Utility Data Institute. So it is reasonable to assume that the production cost threshold could be around 2 cents/kWh or less in order to successfully compete with bulk power sales in the new electricity marketplace. Thus, decisions to build new central station power plants in the future will be based on three criteria:

- Cost of electricity;
- Short construction lead time;
- Flexibility of the technology to achieve performance and cost goals in plant sizes ranging from 100 mW to over 1000 mW;
- The ability of the technology to meet ever-tightening environmental requirements without significant additional capital costs.

NRECA sees a continuing important role for coal in the new generation business. Central station power has the capability to achieve the low cost of electricity that the new marketplace will demand. And domestic coal reserves will provide the long-term low-cost fuel that can make this possible. However, the economics of scale of central station facilities is essential for coal plants to realize low-electricity production costs.

VI. TOMORROW'S COAL-FIRED POWER PLANTS

A consensus exists in the rural electric program that new central station power plants will generally be smaller than in the past. A few hundred megawatts will be more typical than a thousand megawatt or more. And modular plants offering short construction lead times and consistent performance over a range of sizes will dominate.

Although the generation part of the utility business will likely be unregulated and compete in the open market for electricity sales, from the environmental point of view, it will continue to be strictly regulated.

Hundreds of pages of regulations have been drafted to implement power plant SOx and NOx reductions required under the nation's 1990 Clean Air Act. Now, in 1996, the legislative and regulatory focus has shifted to reduce the output of CO2 and other "greenhouse gases," which some scientists believe are causing global warming.

Too, solid waste from power plants is increasingly the focus of proposed regulations under such legislation as the Endangered Species Act, the Clean Water Act, the Toxic Substances Control Act, the Resource Conservation and Recovery Act, and the Comprehensive Environmental Response Compensation and Liability Act - better known as Superfund.

The evolutionary development process leading to vast improvements in coal-fired central station power plants began in the 1960s with the development of fluidized-bed boilers. Atmospheric fluidized-bed (AFB) and pressurized fluidized-bed (PFB) boilers were seen as a potentially better way for utilities to burn virtually all ranks of coal directly while meeting the old 90 percent sulfur-removal requirements of the nation's first Clean Air Act. While direct combustion of coal via fluidized-bed boilers offers many advantages and will continue to be an important power plant option in many parts of the country, NRECA believes that coal gasification offers more advantages than direct combustion for the long-term highly competitive utility generation market.

Integrated Coal Gasification Combined Cycle (IGCC)

Coal gasification, in combination with new advanced power conversion technology such as high temperature turbines and fuel cells, clearly holds the key to central station coal-fired power plants that can compete in the bulk power generation market of the future.

In the early 1980s, ground was broken for the nation's first IGCC power plant at Southern California Edison's Coolwater site in Daggett, CA. This fundamental change in research direction away from direct coal combustion toward coal gasification was in recognition of the greater potential that coal gasification offered in terms of overall environmental performance and costs.

With direct coal combustion, impurities such as sulfur compounds and particulates must be cleaned from the post-combustion gas stream. The key advantage of IGCC is that gasification changes the fuel form from a solid to gasified coal which enables the impurities to be removed before combustion.

In the 100 mW Coolwater demonstration plant, a coal-water slurry was gasified in the presence of oxygen using a Texaco gasifier. The hot raw gas was cooled down, ash particles and other carry-over were scrubbed from the mixture, and then sulfur was chemically stripped from the gas.

The end product was a clean gaseous coal-derived fuel burned in a combustion turbine to produce electricity. Waste heat from the turbine exhaust was recovered to produce additional electrical power through a steam turbine.

And now, in the late 1990s, the U.S. Department of Energy, along with continuing electric utility industry R&D, has made significant progress toward demonstrating major improvements to the basic IGCC cycle

that could usher in coal gasification combined-cycle as the standard central station power plant for the next century.

An IGCC plant based upon the Coolwater configuration could be built today to operate on high-sulfur coal while emitting fewer pollutants than a comparable sized oil-fired power plant. But, the technology has improved from the Coolwater design at a significant rate due to advances being demonstrated under DOE's Clean Coal Technology program. The advanced IGCC system soon to enter demonstration testing at Sierra Pacific Power in Nevada will validate a number of these important advances. Technologies in Sierra Pacific's IGCC such as the pressurized fluidized-bed coal gasifier with in-bed desulfurization and full-stream hot gas cleanup, along with the use of a new generation of high-firing temperature combustion turbines, are critically important steps toward achieving the reduced electricity production costs that will be necessary to compete in the new competitive bulk power market.

Integrated Gasification Humid Air Turbine (IGHAT)

Further improvements to reduce the capital cost of IGCC plants will also be needed to ensure their success in this new competitive market. One approach to lower the cost of an IGCC power plant is to eliminate or perhaps simplify the equipment that is used to recover waste heat from the turbine exhaust and generate additional electricity. EPRI research on IGCC has been focused on how the waste heat could be recovered and expanded through the primary gas turbine power source instead of requiring a separate steam turbine to generate the additional electricity.

Under an EPRI research contract, engineers at Fluor Corporation identified a promising new concept for recovering the exhaust heat. Rather than having air pass directly from the compressor stage of a gas turbine into the combustion stage, this process diverts it into a cooler and then into a vessel known as a saturator. After the compressed air enters the bottom of the saturator, it flows upward against a stream of water that has been heated by the turbine exhaust, the compressed-air cooler, and any other sources of low-level heat. When the air leaves the top of the saturator, it has been humidified to between 10 percent and 40 percent water vapor. This humidified air is then further heated by the turbine exhaust and sent to the combustor, where fuel is added and burned.

In the process, the power produced by a gas turbine expander is proportional to the density of the combustion products that are being expanded. So, by substantially humidifying the air going into the combustor, the density of the combustion stream is greatly increased. Thus, the power extracted by the turbine expander is proportionally increased, thereby producing much more electricity from the gas turbine generator. As a result, a power plant based on a coal gasifier and this turbine could have a heat rate as low as 8,500 Btu/kWh (over 40 percent efficiency) without using a steam bottoming cycle but still reclaiming low-level heat that would be difficult for other cycles to utilize.

In addition, use of the IGHAT cycle could help lower the capital cost of a gasification-based power plant by nearly 20 percent compared with the Coolwater IGCC approach. The reason is that in an IGCC plant, heat for raising steam is obtained by passing the coal gas through large coolers, which are the most expensive components of the gasification system. With the IGHAT cycle, the gas could simply be quenched with water.

A prototype of this turbine has not yet been constructed. But because of the relative simplicity of the IGHAT cycle, and the fact that it is based on current component technology, EPRI believes it could be fully commercialized by 2003.

Integrated Gasification Fuel Cell (IGFC)

An even more dramatic improvement to the coal gasification power plant involves eliminating the combustion turbine altogether and using a fuel cell to convert the coal gas directly to electricity through an electrochemical process. Such direct conversion potentially offers the highest efficiency and lowest emissions of any coal-based plant yet devised.

The integrated fuel-cell coal-gasification power plant, which could be commercially available by approximately 2010, might represent the final step in the nation's quest for clean coal technology. This system could potentially offer the following operational advantages:

- Virtually no SOx and NOx emissions, even with the very highest-sulfur U.S. coals;
- Modularity that lends itself to short construction lead times;
- A capital cost comparable to today's best technology, a new pulverized-coal-fired (PC) power plant with flue gas scrubbers;
- A 20 percent reduction in the bus-bar cost of electricity compared to today's PC plant with scrubbers; and
- A full 30 percent reduction in heat rate - which translates to a 30 percent reduction in CO2 discharge, should that become required as U.S. policy develops on global climate change.

Ideally the fuel cell selected for use with a coal gasification unit should operate at about the same temperature as the gasifier. The most promising candidate is a fuel cell using a molten carbonate electrolyte. The molten carbonate fuel cell (MCFC) technology has been operated successfully on gasified coal. Moreover, it is now operating in a 2 mW electric utility demonstration plant at Santa Clara Municipal Utility in Southern California, and it is being accelerated into commercialization by the electric utility industry's Fuel Cell Commercialization Group (FCCG).

An MCFC produces electricity directly from either gasified coal or natural gas fuel and air without a combustion process. An electrochemical reaction takes place between the hydrogen from the fuel and the oxygen from the air in a closed container, with the molten carbonate electrolyte maintained at 1200°F.

This reaction produces electricity in a manner resembling a battery. It makes no noise. The byproducts are pure water and carbon dioxide.

The first integrated gasification fuel cell cycle will likely be achieved by substituting a molten carbonate fuel cell for the gas turbine in the standard IGCC plant. This alone is predicted to offer a significant improvement in heat rate from 8,900 Btu/kWh down to 7,500 Btu/kWh, with a slight reduction in bus-bar electric costs.

But the big improvement is realized when the molten carbonate fuel cell is "chemically integrated" with the coal gasifier. With this approach, the heat rate of the IGFC plant could be further lowered down to 6,000 BTU/kWh, achieving a coal-pile-to-bus-bar efficiency approaching 60 percent, compared with about 37 percent for today's best pulverized-coal technology.

Chemical integration, the key to such attractive performance, involves configuring the system in a manner such that the fuel cell's unconverted fuel and the fuel's heat content is recycled back into the gasifier. A special methane-producing gasifier would be required to maximize the chemical content of the coal-derived gas. Also, a hot gas clean-up step would be employed to clean the coal gas for use in the fuel cell without first cooling it down.

These are, of course, engineering developments that would have to take place successfully before such an advanced IGFC could be commercialized. But these are just engineering problems to be solved, and do not require any scientific breakthrough to achieve. As a result, EPRI believes this promising IGFC plant could become a commercial reality by 2010. If so, it could truly represent the final developmental step in the quest for clean coal-power generation.

VII. CONCLUSIONS

Deregulation of the electric utility industry would result in many changes to the way business is done today. In the unregulated, market-driven GENCO and ESCO businesses, electricity sales will be dominated by the low-cost providers.

ESCOs could successfully capture up to about 10 percent of the 175 gigawatts of new U.S. capacity needed by 2010 with dispersed generation. Dispersed generation electricity costs will be able to bear a premium above central station bulk power generation because the ESCO customers will be provided additional value-added services. Also, distributed generation will realize some payback from deferred transmission or distribution construction.

Central station power plants are expected to continue to provide the major portion of the nation's new bulk power needs. But only very competitive low-cost generating stations will be constructed. These will

likely be built in smaller increments of 100 mW or so compared to today's larger plants.
Coal will continue to be a major factor in central station bulk power generation. And the economics and environmental performance of coal gasification combined cycle power plants will likely position this option as the dominate technology for coal fired central station generation.

DOE's clean coals technology program has been a major factor in bringing coal gasification combined cycle power plants to commercial readiness. Without this promising option, the nation's abundant coal resource might not continue to be in demand in competitive utility markets where low-cost dominates but emission regulations continue to tighten. But further progress on capital cost reduction and performance improvement is essential to ensure coal's long-term place in such a market.

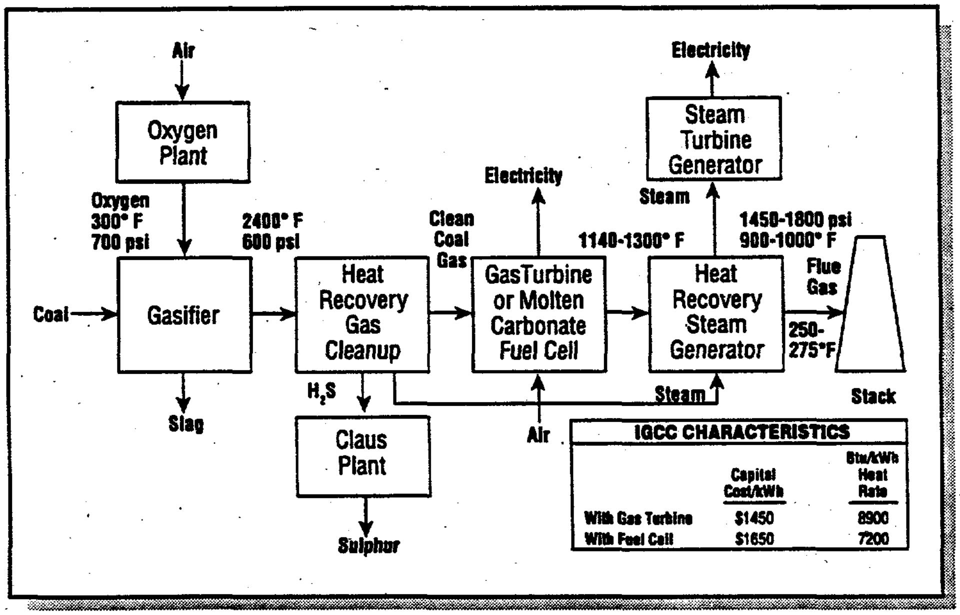
LOW COST COAL-FIRED ELECTRIC CO-OP GENERATING PLANTS

(Ref: Utility Data Institute 1995 Ranking)

G&T Co-op	Plant	Location	Production Cost (cents/kwh)
Basin Electric Power	Laramie River	WY	0.983
Associated Electric Co-op	Thomas Hill	MO	1.127
Basin Electric Power	Antelope Valley	ND	1.136
Minnkota Power	Young	ND	1.189
Old Dominion	Clover	VA	1.213
Associated Electric Co-op	New Madrid	MO	1.250
United Power Association/ Cooperative Power Association	Coal Creek	MN	1.260

Generation Options	SO_x Removal (%)	NO_x Emissions (lb/MBtu)	Solid Waste (lb/MBtu)	Heat Rate (Btu/kWh)	Capital Cost ($/kWh)	Potential COE ($/kWh)	Commercial Availability (Yr)
PC W/FGD	90	0.3	110	9300	1160	2.0	Now
AFB	92	0.1	147	9700	1600	2.2	Now
PFB	92+	<0.1	144	8720	1500	2.1	1997
IGCC	99	0.14	50	8900	1450	2.0	1997
IGHAT	99	<0.0005	44	8500	1200	1.7	2003
IGFC	99.9+	0.0	29	6500	1200	1.6	2010

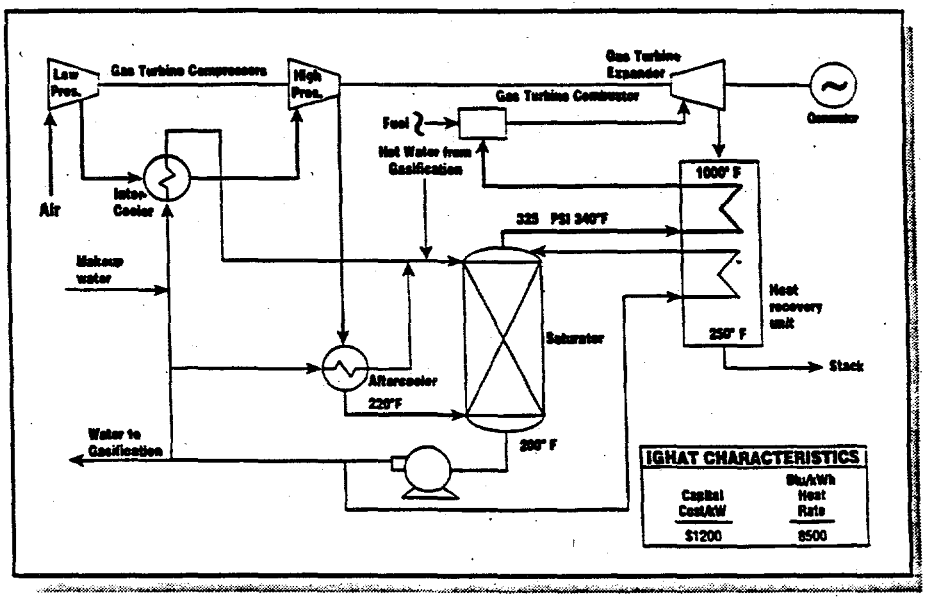
The integrated coal gasification combined cycle (IGCC) power plant could become the most environmentally superior and economically competitive coal-fired generation option compared to today's standard pulverized-coal (PC) plant with flue gas desulfurization (FGD). Improvements such as the integrated gasification humid-air turbine (IGHAT) and integrated gasification fuel-cell (IGFC) plant will offer substantial environmental and economic advantages compared to today's PC plant or advanced direct coal combustion options such as atmospheric fluidized-bed (AFB) or pressurized fluidized-bed (PFB) boilers.



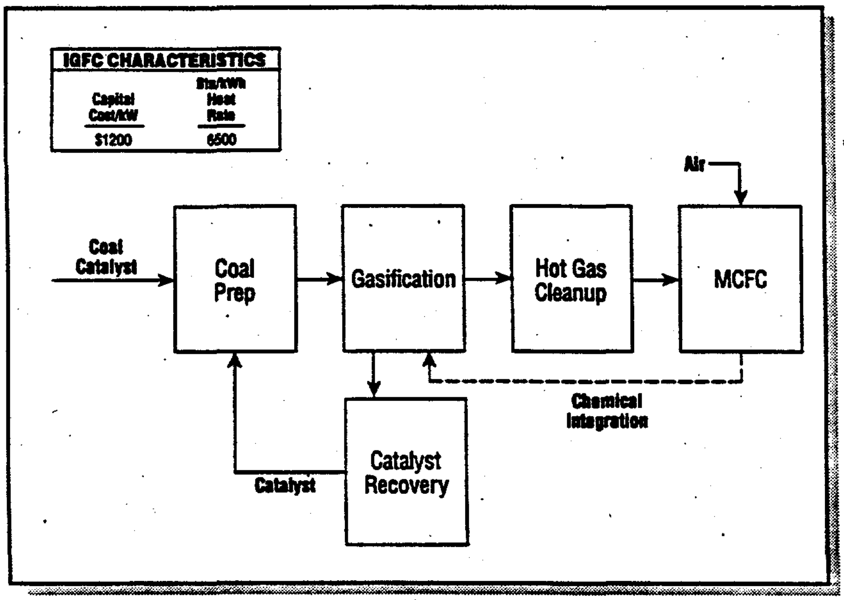
IGCC CHARACTERISTICS

	Capital Cost/kWh	Btu/kWh Heat Rate
With Gas Turbine	$1450	8900
With Fuel Cell	$1650	7200

Integrated coal gasification combined cycle (IGCC) based on Southern California Edison's demonstrated Coolwater Plant design could be configured with a gas turbine or a molten carbonate fuel cell (MCFC) as the primary generation source. MCFC carries a $200/kW capital cost premium, but overall electricity cost and plant heat rate would be improved.



Integrated gasification humid air turbine (IGHAT) improves IGCC plant performance and cost by expanding warm humidified air directly through the gas turbine, thus eliminating the IGCC heat recovery steam generating equipment.



Simplified Plant Configuration for an Integrated Gasification Fuel Cell (IGFC) power plant employs a methane-producing gasifier, chemically integrated with a molten carbonate fuel cell, and hot gas cleanup. Such a plant potentially offers nearly zero SOx and NOx emissions, the lowest electricity cost and the best heat rate (nearly 60 percent efficiency) of any power plant configuration yet investigated for use with high sulfur coal.

THE CHANGING FACE OF INTERNATIONAL POWER GENERATION

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Ladies and Gentlemen,

I think it was Churchill in his great Iron Curtain speech at Fulton, Missouri, at the end of the last war, who referred to the American and the British as "Two great peoples divided by a common language" - I sincerely hope his remark will prove invalid today. At least during lunch, we will not have to resort to instantaneous translation as I did a few months ago in Moscow, when I was giving another short talk. Towards the end I noticed that terrible glazed look on the faces of the audience, which betrayed the fact that I had said something - through the interpreter - which was obviously totally incomprehensible. In fact I had used the expression "Out of sight, out of mind," but it was not until afterwards that I discovered it had been translated as "Invisible Idiot." Let that be a lesson against using the vernacular.

Before starting, just a few words about the World Energy Council. It was started in 1923, and with over a hundred member countries, is today the world's prime energy strategy and analysis organisation. Our study projects carry input from the industrialised world, the developing world, and of course the economies in transition in E. Europe and the Former Soviet Union. Almost more important, by working "bottom up" from the grass roots of local energy sectors we both collect input from the operatives - the very people, like yourselves, who manage energy - and we cross-fertilise data, information, and the results of our study work worldwide. We are increasingly acting as "facilitators" to "get things done." An example was holding the first ever African Energy Ministers Conference, which concentrated on power pooling arrangements and the first attempts at coordinated regional energy development. Before the conference such interconnections really only existed in the seven Southern African countries. Today, 1½ years later, interconnections are already being started in the six East African countries, the Arab Grid is being extended in the Maghreb (North Africa), and a central plan has recently been approved for power pooling in the French-speaking countries of Central and West Africa.

Although we are non-commercial and non-governmental, we work closely with governments the world over, as well as with over 40 of the leading institutions in the energy and energy-related sectors

- the World Bank, the principal regional financing agencies, the single energy associations - The World Petroleum Congresses, International Gas Union, UNIPEDE the European electricity institution, the World Trade Organisation, International Chamber of Commerce, the UN in all its guises, etc.

You may well not have heard of us if you are not intimately concerned with the international energy scene. Alternatively, you may have heard or seen references too much of the longer term work we do, but in either case I would suggest you are going soon to hear a lot more about us. The WEC US Member Committee is based in Washington and called the US Energy Association. Every three years we hold a major international Congress, always in a different country, and the next, the 17th WEC Congress, is being organised by the USEA in Houston in September 1998. Barry Worthington, its Executive Director, is with us today, and if you want to know more about its menu and attractions, please ask him.

"The Changing Face of International Power Generation" is a subject which could occupy several hours, but don't let me give you indigestion too early on. I will limit my remarks not to changing technologies and improved performance, not to changing fuel mixes, not to the incessant - but so far unproven CO_2 problems, not to SO_x's and NO_x's, of which you will have had your fill during this Conference, **BUT** to the international generator's marketplace, and even here I will devote little of what I have to say to the OECD countries but much to the developing world. I shall speak to future global electricity demand, generating capacity build, its financing issues, and to the commercial generating opportunities which now abound outside the States.

Such a rich diet may go some way to proving Voltaire's maxim that "Thinking depends on the stomach." So, while I remain hungry, you can chew over what I have said, because I get the very pronounced feeling in the current turbulence caused by the upheavals in your own domestic power sector, that US utilities are missing out on commercial opportunities in many overseas markets which, with prudence, could eventually offer attractive returns.

First of all, the general context. Energy demand perspectives including our own, those of the IEA, the World Bank and others, all point to a virtual doubling of global primary energy demand over the next 25 years. Let me interpret what that means. By 2020 more than 90m b/d of oil are likely to be consumed annually - an increase over today of 27m b/d, or the whole of OPEC's current crude oil production. Annual coal output will double to about 7 billion tonnes - almost double the entire known reserves in Canada or the UK. Annual gas demand will more than double to approximately 4 trillion cubic meters - almost equal to the entire current US gas reserves. In all this, fossil fuels will continue to dominate the global energy sector for decades to come, albeit with some ultimate growth of both nuclear and hydro. We see new renewables (solar, wind, etc.) remaining at or close to their 2% - 3% share of today's global demand, unless massive government or other funds are allocated to support their growth. Energy lead times are long and it is unlikely over the next 25 years that new renewables will either make in-roads into existing systems or play much of a part in the incremental growth during this time, unless the potential CO_2 problem becomes a scientific reality.

So much for the contextual perceived wisdom. It is not until these global demand figures are analysed, however, that the picture becomes clearer as to where or why the main demand will occur.

Up to 2020 it is likely that some 90% of this natural energy growth will occur in the developing countries - mainly in Asia and Latin America. North America, by contrast, will probably experience only a 12% - 13% growth up to 2020, while the 60% of global demand consumed by the OECD will drop to under 50% for the first time. By contrast, the developing countries demand will increase from 28% today to about 40% of the total by 2020. The East European and CIS demand is likely to remain constant at about 13%. But in this alarmingly short space of only 25 years, let us go further into the analysis. 90% of incremental energy demand growth will occur in developing countries, because of rapid population growth and economic development and the fact that growth in many cases will start from a low base. Over half of this incremental growth is likely to take place in just six areas: China, India, Indonesia, Brazil, Pakistan and the Malaysia/Thailand peninsula.

What of electricity generating capacity in all this? Well, we in the WEC, like many others, are predicting that more generating capacity will be built in the next 25 years than was built in the last one hundred. Much of this will result from the rapid urbanisation of developing countries, and much from the march of technology in transmitting power efficiently over much greater distances. In 1960 only 28 countries had greater urban than rural populations By 2020, 88 countries are expected to have 50% or more of their populations living in cities. Cities like Delhi, São Paulo, Manila, Bombay, Beijing, Jakarta and Teheran are all recording annual population growth rates of +3% or more - and do not forget that an annual growth rate of 3% means a doubling of population in 23 years. Do not also forget the result of a recent IEA study which showed that per capita consumption of energy in urban and peri-urban areas is usually between 2.5 and 3.0 times that experienced in rural communities. As an example of the long haul grid transmission, the huge 40 Gigawatt Inga hydro scheme on the Zaire River as the future supplier to markets as far afield as Egypt and Southern Africa, separated by 8,000 miles, is probably only some 20 years off. The feasibility study is already nearing completion and the political and economic in-fighting has already begun, not only for the project itself, but also for grid wayleaves, etc.

In 1920 Lenin defined communism as "Soviet power plus the electrification of the whole country." He meant by this the projection, in one leap, of the whole of a backward country into the forefront of industrialisation. He might have been proved right had it not been for the might of your own economy together with those of others and backed by our political wills to overcome. However, let us concentrate today not on the flagging energy sectors of Eastern Europe and the CIS - where, to give you some idea of current economic regression, the Russian Federation consumed 20% less oil in 1994 than it did in 1993 - not on the slow growth of the OECD generating sectors - but on the developing countries and their rapidly expanding electricity demand.

Here we should differentiate between what I call "old assets" (existing power systems) and "new assets," involved in the massive incremental growth of the power generating sector. The growth of these "new assets" is not only a phenomenon in its own right, it is turning out to be a considerable stimulus for global capitalism. Let us not forget that the global power sector at nearly 40% is by far the world's greatest absorber of infrastructure capital. Electricity development consumes more finance than communications, highways, or water. It also carries huge political clout. A developing country politician can win more votes faster - if he or she operates within a voting system - by bringing in electrification to a village. Go to a country like Uganda and you will see this. Rural power development there has not followed any logical pattern - it has largely followed the whims of individual ministers. Utilities in many such countries have until now been government owned and run, financed starved and the primary cause of lack of industrial productivity due to black and brown outs and general inefficiency. Often their revenues did not even cover their fixed costs because to a greater or lesser degree governments supported subsidies to consumers, who in many cases were unable economically to pay tariffs which covered costs.

Approximately 60% of all energy supplied globally to consumers today is subsidised by governments in one form or another - and a large part of this 60% inevitably occurs in the developing world. Consumer tariffs are therefore often low and many do not allow of a decent return on capital invested. So, with regard to such "new assets" the message must be to investigate and take action with great prudence and almost inevitably in conjunction with a local partner which knows the local scene.

But all this is changing. Governments faced with huge and increasing demand for electrification and new assets, are realising that they cannot cope with the pressures for finance, control and the day-to-day management and maintenance essential for all this new capacity. This has resulted in a number of different national reactions. On the one hand markets are being liberalised - although by different methods and at different rates, and this may offer commercial opportunities for the astute external investor: But, on the other hand, developing country governments often maintain their ingrained belief that energy must belong to the national patrimony, and some are correspondingly reluctant to adequately loosen controls. This causes a range of problems.

"Old electricity assets," the existing power systems, are in many cases also being liberalised. Let me give you some examples. Brazil is about halfway through its privatisation programme. Chile has fully privatised with adequate commensurate changes to government regulation to ensure overall economic and social success. Argentina is in the process of privatising by individual sector, generating, transmission and marketing. The Venezuelan electricity sector now has local private investors as well as foreign owned assets. In Africa, Egypt has privatised its generating sector. Kenya Light and Power, previously 100% government owned, now has only a minority government shareholding. In Zimbabwe ZESA, the national generator, with some 2,000Mw now has Malaysian minority shareholders, who will become majority shareholders when capacity is increased by 50% over the next 4 years. Of almost more importance, industrial consumer prices in Zimbabwe have been increased by some 250% and the "new asset" investment in generating capacity has a planned 20% real rate of return. In Zambia, the Copperbelt Power Company is to be sold; in Botswana a privatisation plan is to be announced shortly; and in Namibia local private sector shareholders now own all the principal generating and transmission assets. Further south, South Africa is in the throes of liberalising its power sector which generates 67% of all the power in the Continent of Africa.

In Asia, China and India, with some 10% of total current global electricity demand, are planning to build new capacity up to 2020 which, by that year, could equate to 25% of global generation. This could mean the construction of a medium sized power station every week up to 2020. In Malaysia and Indonesia, power demand is growing faster than the already rapidly expanding economies.

But there are caveats; relate all this growth to population predictions and you will find that by 2020 China, for example, will still only have a per head generating capacity equal to 30% that of the US today. Such rapid growth in the developing world coming on top of a lack of finance, often poor technical management, and equally poor financial control, is now faced with a fourth quandary - that of increasing local pressure to apply very much more stringent environmental protection controls first in a local sense, and probably thereafter in a global sense.

We in the WEC have done some work with the World Bank, which shows that international financing (from both agency and private sector sources) will probably cover only between 30% - 40% of the huge future requirements of the electricity sector. In my view, the outstanding questions in this entire growth scenario are "Where will the other 60%-70% come from?", and "Will the potential lack of financing become a real constraint to growth?" Can, or will, many developing countries not only liberalise their power sectors but render then sufficiently attractive to investors to mobilise local capital? And at the same time will they set up the necessary institutions to attract the often high local savings rates? To know more about all this we now await the outcomes of two current WEC study projects, due to be completed shortly: the first on "Liberalisation of the Global Energy Sector," and the second on "Future Energy Financing." The results will make fascinating reading.

The scale of such private power development of itself probably presents the greatest problem of all. As an example, private sector power development may, in India, be regarded as the solution to one of the country's major development problems, but internal bureaucracy, the rivalry between government departments, and the way legal process work have all combined to slow down the whole process of private investment. Foreign investment rates, having soared during the last three years in Malaysia, Indonesia, Argentina and Chile, have also now begun to slow down. And over this whole scene is cast the shadow of the debt crisis of the 1980s. About 30% of the money then lent to Third World governments was to have been invested in power projects. Today's scene is different, but nonetheless tense. Today's investors are considerably more prudent than yesterday's, and the loans do not necessarily go to governments but it is still necessary for such agencies as the World Bank to provide some political protection by themselves taking small stakes in satisfactory projects. Risks however remain, not least depreciating exchange rates and the inability of governments to change regulations and tariffs at the same rate as they encourage private sector investments.

This, then, is the heart of the changing face of international power generation as seen by the WEC. Let me encourage you to come and hear much more about it, by participating in the WEC's 17th Congress to be held in Houston from 13th - 18th September 1998. We are expecting between 6,000 and 7,000 delegates to the event, one of a series which over the years have established themselves as the prime global events of the international energy scene.

If I have given you indigestion, this can only have resulted from one of two causes - boredom, in which case you have my apologies; or from a surfeit of information, in which case you have my commiseration. But above all, let us not forget that to operate in the developing world we all have to deal primarily with local politics and local politicians, and in this context you may care to remember the little aphorism of one of our British maverick socialist politicians, Lord Charlfont, who maintained that "you can always rely on politicians to produce wise, intelligent and statesmanlike decisions .... having first exhausted all other options!"

Panel Session 3

Issue 3: Environmental Issues Affecting CCT Deployment

International Environmental Issues and Requirements for New Power Projects

presented by

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Purpose of Presentation

- Discuss emerging role of financial entities in determining environmental requirements for international power projects

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Emerging Conditions

- Increased economic growth overseas resulting in increased demand in electricity
- Move towards privatization of electricity sector overseas

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Examples of Announced Privatization Energy Projects by County

COUNTRY	# OF PROJECTS	CAPACITY (MW)
China	6	5,850
India	6	2,879
Pakistan	3	3,766
Turkey	11	6,900
Brazil	19	11,475
Argentina	10	6,472

Source: Hagler Bailly Consulting, September 1996

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Resulting Activities

- Independent Power Producers (IPPs) investing overseas
- International Public and Private power project financing by governmental and multinational entity sources

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Types of Governmental and International Financial Entity Sources

- Seven major sources

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Types of Governmental and International Financial Entity Sources

- Multinational Development Banks (MDB)
- Regional development banks
- National development banks
- National export banks and agencies

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Multinational Development Banks (MDB)

- International Bank for Reconstruction and Development (IBRD) or The World Bank
  - International Development Association (IDA)
  - Multilateral Investment Guarantee Agency (MIGA)
  - International Finance Corporation (IFC)

Regional Development Banks
(examples)

- North American Development Bank
- Inter-American Development Bank
- African Development Bank
- Asian Development Bank
- European Bank For Reconstruction and Development

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Electric sector projects in multilateral bank funding pipelines as of 1995 ($US milllion)

REGION	*Asia*	*LAC*	*NIS/EE*	*Africa*	*TOTALS*
World Bank	5,193	783	1,315	621	7,912
IDB	–	1,706	–	–	1,706
AfDB	–	–	–	249	249
ADB	2,065	–	–	–	2,065
Totals	7,258	2,489	1,315	870	11,932

Source: KBN, 1996.

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National Development Banks
(examples)

- Banobars
- Nacional Financiera
- Banco Nacional de Desarrollo Economico
- Industrial Development Bank of India
- National Finance Development Corporation of Pakistan

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National Export Banks and Agencies
(examples)

- US Eximbank
- Japanese Eximbank
- Overseas Private Investment Corporation (OPIC)
- US Trade and Development Agency

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Types of Governmental and International Financial Entity Sources

- Private (non-government) project financing sources
- Major international commercial banks
- Other private project financing sources

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Private (non-government) Project Financing Sources

- Major International Commercial Banks
  - Citibank
  - Deutsche Bank
  - Others

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Other Private (non-government) Project Financing Sources

- International Finance Companies
- International Investment Banks and Equity or Dept Funds
- International Corporations
- International Trading Companies

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Financing By Major Financing Entities Requires Environmental Approval

- Financing entity's own environmental policies and/or
- Policies of host country or other entity
- IPP may have its own environmental policies

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Problem For IPPs

- Similar kinds of environmental requirements and issues

but

- multiple financing entities for same project with different environmental approvals

and

different emphases on environmental requirements and issues

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Similar Environmental "Requirements"
(examples)

- Environmental Impacts Assessments
- Environmental Management Plans
- Environmental Monitoring Plans
- Risk Assessments/Risk Management Plans

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Similar Environmental Issues
(examples)

- Host country environmental policies
- International conventions
- Emission and effluent limitations
- Air, water, geological, and ecological resources
- Socioeconomic quality (especially resettlement)
- Public participation

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Confounding Conditions

- International financing entities often require or defer to World Bank's numerical pollution limits

- Approvals often must conform with unofficial, draft, and outdated World Bank guidelines

- Host country requirements often more stringent

- Some international commercial banks require USEPA type of compliance

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Consequences for IPPs

- Conflicting environmental "requirements" and conflicting emphasis on environmental issues

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Consequences

- International environmental "standards and regulations" for power projects are evolving and not consistent
- World Bank becoming international "EPA", not by design but by default

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Similarity and Differences between World Bank and USEPA

- Similarity
  - Both deal with environmental issues and give project approval

- Major Differences
  - Guidance vs. compliance
  - International vs. US setting
  - Sovereignty issue of World Bank
  - Different missions

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Different Missions

- EPA's mission
  - implement and enforce environmental policies in US
- World Bank's mission
  - promote sustainable development in developing countries
  - provide loans that contribute to economic growth

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Environmental Policies of International Financial Entities Differ Significantly

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Comparison the international environmental "Standards and Regulations" for power projects

FINANCING ENTITY	ENVIRONMENTAL POLICIES	EIA GUIDELINES, FORMATS AND PROCEDURES	NUMERICAL LIMITS FOR AIR, WATER WASTES	RISK ASSESSMENT GUIDELINES
WORLD BANK GROUP IFC MIGA	DETAILED	SPECIFIC FOR DIFFERENT PROJECT TYPES INCLUDING POWER	YES - (TRIGGER VALUES), PLUS HOST COUNTRY	GENERAL
ASIAN DEV. BANK	DETAILED	SPECIFIC FOR DIFFERENT PROJECT GROUPS	NO - DEFER TO HOST COUNTRY OR WB	DETAILED
INTERAMERICAN DEV. BANK	GENERAL	GENERALLY FOLLOW WB AND HOST COUNTRY	NO - DEFER TO WB	NO SPECIFIC GUIDELINES
OPIC	GENERAL	DEFER TO WB	NO - REQUIRES WP COMPLIANCE	NO SPECIFIC GUIDELINES
US EXIMBANK	GENERAL	DEFER TO NEPA AND WB	NOT COMPREHENSIVE, DEFER TO WB	NONE
COMMERCIAL BANKS	INTERNAL	DEFER TO WB	DEFER TO WB (SOMETIMES EPA)	NONE.

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Examples of Evolving Numerical Limits For Power Projects

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Recent Trends/Issues Involving International Power Project Approval

- Financial institutions don't understand World Bank policies and guidelines
- Projects being required to meet a common (but not agreed upon) set of environmental standards
- Increasing requirement for baseline data collection e.g. air quality

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Recommendations For Understanding/Expediting the MDB's and other financial entities's environmental approval process and how to expedite this process

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Maintain Close and Frequent Communications With Banks, Financing Entities and Governmental Agencies

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Determine All Possible Approving Entities, Realize There Are Multiple

- Host Country- federal, state and local
- Multinational financial entities, especially the World Bank
- Private financial institutions

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Know the Difference Between Approving Entity's Policies, Standards, Procedures, Recommendations and Guidelines

- What ones are in effect and apply to your project?
- Are they changing? When?
- Guidelines are often moving targets

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Define Your Project Early

- Avoid evolving engineering designs
- Understand how environmental requirements will affect your design
- Link environmental assessment with early part of financial cycle

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Other Recommendations

- Avoid poor site selection

- With increasing requirements for baseline data collection and monitoring
  - Consider effects to schedule
  - Need to negotiate reasonable requirements
  - Weigh project costs vs. monitoring costs

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Other Recommendations

- Conduct scoping
- Involve public and NGO
  (assure public participation conditions are met)
- Garner public support
- Avoid relocation and resettlement
  (moving people can be political fatal flaw)

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The Objective of a Successful EIA Strategy Is to Reduce Uncertainty in an Uncertain "Regulatory" Environment

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