Abstract

An industry-standard financial model of a coal-fired power plant was used to compare the economic benefits and costs of new technologies for managing carbon. Selected results are reported, and conclusions drawn on directions for future research.

Issue: The Role of Coal

Half of the electric power generated in the United States comes from coal and almost one-third of the manmade carbon dioxide emitted comes from that same coal combustion.

Now the power industry is faced with the potential need to manage carbon dioxide.

Where will the policy makers look to start action on this problem? The transportation sector represents millions of private automobiles mostly driven by citizens of voting age. For industries struggling to compete with low-wage foreign competition, an extra tax on carbon could force the employer to shift production overseas. In contrast, the electric power industry cannot readily import electricity from overseas.

If and when policy makers decide to control carbon dioxide emissions, the electric power industry is likely to be among the first to be limited. A system planner has many variables to consider. Renewables such as wind and solar are intermittent, and are most suitable for certain geographic territories with these resources. They are not available at the scale necessary to replace current baseload and intermediate duty power plants, which depend on fossil fuels.

The power industry has successfully met the challenge of reducing sulfur dioxide, oxides of nitrogen, and particulate matter. Carbon dioxide challenges the industry in a new way, because the quantities are vast and the technologies are still under development. With many alternative technologies under review, a major supplier to the power industry looked for a tool to help improve their understanding of the financial impact of alternative technologies to concentrate carbon dioxide.

Alternatives to Control Carbon Dioxide from Coal

It would be more practical and economical to store the carbon dioxide if it were concentrated.
In a conventional plant, carbon dioxide normally constitutes 15% or more of the exhaust gasses, with nitrogen accounting for about 81%. Therefore, much of the current research revolves around producing an exhaust stream with a high proportion of carbon dioxide.

There are a number of ways to obtain a concentrated stream of carbon dioxide. This paper will consider them:

- during combustion (oxygen-fired)
- after combustion (carbon dioxide scrubber)
- before combustion (and after gasification, using a water/gas shift reactor and carbon dioxide scrubber)

The first two processes for concentrating carbon dioxide, during and after combustion, apply to a conventional steam-electric power plant. Combustible fuel is burned in a boiler, where the heat from combustion generates steam. The steam turns a turbine, to change thermal energy to mechanical energy, and the rotation of the turbine spins an electric generator, to make electrical energy. The third process uses high pressure gasification, and will be discussed later.

During Combustion (Oxygen-Fired or Oxy-Combustion)

The first process for concentrating carbon dioxide, oxy-combustion, does not work on the carbon dioxide directly. Rather, it works by separating the oxygen from the air before combustion and exhausting the nitrogen and other trace inert gasses to the atmosphere. Cryogenic air separation technologies to produce high quality oxygen and nitrogen are well-established, although a power plant will utilize more oxygen than a typical gas separation plant produces.

A cryogenic air separation plant will require significant auxiliary power to operate, accounting for much of the cost of carbon management from this technology.

Coal burns in pure oxygen at an elevated temperature, so oxy-combustion designs include substantial recirculation of the carbon dioxide-rich exhaust gas. As much as three-quarters of the flue gas may be recirculated, and this has several advantages. Diluting the oxygen with recirculated carbon dioxide reduces the temperature of combustion. The increased volume brings the gasses into the same design regime as an air-fired boiler for heat transfer surfaces.

Oxygen plus recirculated carbon dioxide has many of the same characteristics as air in the furnace. It may be practical to utilize many of the same design, fabrication and operation techniques on an oxy-fired boiler as on a conventional air-fired boiler.

Since air-borne nitrogen has been removed by the Air Separation Unit (ASU), many fewer oxides of nitrogen (NO_x) are formed during combustion. On account of this, a Selective Catalytic Reduction (SCR) System for de-nitrification may not be needed. The recirculated carbon dioxide stream also allows for NOx destruction.

The Babcock & Wilcox Company (B&W) conducted a Phase I study for an oxygen-fired system for the City of Hamilton, Ohio to retrofit an existing 22 MWe boiler. The project has not yet moved forward to construction pending Phase II DOE funding.

More recently, SaskPower announced in Regina, Saskatchewan, Canada, on October 30, 2006 that it has formed a partnership with The Babcock & Wilcox Company and Air Liquide to develop a 300MWe net oxycombustion power plant to meet the need for additional electricity expected in Saskatchewan in 2012. Canada is a member of the Kyoto Accord, therefore SaskPower needs to limit any increase in its emissions of carbon dioxide in the future.

SaskPower plans to make a decision in mid-2007 on whether to proceed with this oxy-combustion plant or employ other carbon management techniques.

After Combustion (Carbon Dioxide Scrubber)

An alternative way to remove carbon dioxide from the exhaust of a coal-fired power plant is to scrub the exhaust, in an operation similar to a sulfur dioxide scrubber for flue gas desulphurization (FGD). A carbon dioxide scrubber will use a significant portion of the steam from the power plant, to heat and regenerate the used carbon dioxide solvent.

Reagents to scrub carbon dioxide may work by chemical absorption, or by physical absorption.

Both types of scrubbers share the same basic flow. The carbon dioxide-rich gas flowing up encounters the solvent in a tower where the solvent is spraying down. Then the carbon dioxide laden solvent moves to a stripper tower, where it is heated to free the carbon dioxide. Plant steam is used to heat the solvent. The warm, lean solvent is recycled back to the spray tower to absorb more carbon dioxide. The concentrated carbon dioxide may be pressurized and cleaned, for long-term storage, Enhanced Oil Recovery (EOR), or another function, similar to the process with Oxy-combustion described above.

Physical absorption is more efficient when the gas is at a high partial pressure. Since the flue gas in steam boilers normally is at or near atmospheric pressure, chemical absorption is appropriate for post-combustion scrubbing of a steam boiler.

Chemical absorption of carbon dioxide is already used on submarines, where carbon dioxide is commonly removed with a chemical scrubber using monoethanolamine (MEA). When cold, MEA takes in carbon dioxide. When heated, MEA gives up the carbon dioxide, often in a stripper tower. Plant steam is used to heat the solvent.

Carbon dioxide scrubbing is also used in the petrochemical and food processing industries, although not at the scale needed by the power generation industry. A variety of aqueous solutions are used, especially the mono, di-, or tri-ethanol amines, di-isopropanol amine, and others. An amine is an organic compound that contains a nitrogen atom bound to carbon and sometimes hydrogen atoms.

While MEA is the most established solvent for carbon dioxide removal, a number of proprietary designer solvents are under development, which use less heat to free the carbon dioxide during the stripping side of the cycle, and which require less solvent. The study by the Environmental Protection Administration (EPA) entitled "*Environmental Footprints and Costs of Coal-based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*" made the following comparison of the effectiveness of chemical solvents for carbon dioxide removal:

Solvents for Carbon Dioxide Removal

Supplier	Solvent	Solvent Loss, lb/ton of CO_2	Solvent Cost, $/lb	Solvent Cost, $ per ton of CO_2	Steam Use, ton per ton of CO_2
Non Proprietary	MEA	2 to 6	0.60	1.20 to 3.50	2
Econamine, Fluor	MEA plus Inhibitors	3.2	0.70	2.30	2.3
KS-1, MHI	Hindered Amines	0.7	2.30	1.55	1.5
PSR, Amit Chakma	Amine Mix	0.2 to 1.8	Unknown	Unknown	1.1 to 1.7

The costs used in this study for the monoethanolamine scrubber were drawn from the "*Cost and Performance Comparison of Fossil Energy Power Plants*" sponsored by the National Energy Technology Laboratory of the U.S. Department of Energy. Costs for the power plants using the proprietary solvents were ratioed from the costs of MEA. Costs for the ammonia scrubber came from preliminary work such as the Powerspan slipstream unit at the R. E. Burger plant of First Energy at Shadyside, Ohio. The Department of Energy and WE Energies announced a 5-MW slipstream test of ammonia as a carbon dioxide solvent at the Pleasant Prairie Power Plant in Wisconsin, during 2007. A carbon dioxide scrubber would also require equipment to dry and compress the carbon dioxide, to make it ready to pump underground for Enhanced Oil Recovery or for long-term storage. Like the other methods of carbon management, carbon dioxide scrubbers would add significantly to the cost of electricity.

Before Combustion (Gasification with Water Shift Reactor and Carbon Dioxide Scrubber)

Coal gasification itself is an old and well-known technology. Coal was heated to produce town gas for city lighting in the 1800s, before electric lighting became widespread.

An Integrated Coal Gasification Combined Cycle (IGCC) plant operates by first heating the coal and injecting steam. This partially oxidizes the coal to form a synthesis gas. The synthesis gas is then used to fuel a high-efficiency combustion turbine. The combustion turbine also provides compressed air to the Air Separation Unit (if an oxygen-fired design) or the gasifier, hence the name "Integrated." Exhaust gas from the combustion turbine passes through a Heat Recovery Steam Generator (HRSG) which powers a steam turbine. This accounts for the "Combined Cycle" part of the name.

An Integrated Coal Gasification Combined Cycle plant produces carbon dioxide on the same scale as a conventional steam-electric plant, from both the gasifier and the combustion turbine. In a typical gasifier, an exothermic reaction of coal, and oxygen or air takes place, and the coal is converted into molecular hydrogen, carbon monoxide, and carbon dioxide. The hot gas (for example 2,500F) is cooled in a radiant syngas cooler or similar device, contributing more heat for steam to the steam turbine generator. At this point in the cycle, an IGCC power plant has produced carbon dioxide, similar to the steam electric plant. In an IGCC, the carbon dioxide can be captured after the gasification stage and before the combustion turbine stage, by using a Water/Gas-Shift reactor to convert the CO to CO_2. The liberated hydrogen then fuels the combustion turbine without producing carbon dioxide at the combustion stage. The combustion process in the turbine is:

$$2H_2 + O_2 \rightarrow 2H_2O$$

The hydrogen-fueled turbine gas produces H_2O (water) as an exhaust gas, rather than carbon dioxide.

Because the carbon dioxide is produced at high pressure, the IGCC process can utilize physical absorption, rather than a chemical solvent, to capture carbon dioxide from the exhaust stream of the water/gas-shift reactor. Liquid physical solvents such as Selexol and Rectisol can be used for Acid Gas Removal, both for carbon dioxide and for certain other undesirable gasses. Rectisol requires chilling the gas to cryogenic temperatures, thus adding significant expense.

The estimates used here assume Selexol as the solvent to absorb carbon dioxide from the gas, after the water/gas shift reactor stage. With the carbon dioxide removed, the hydrogen-rich treated syngas is sent to fuel the combustion turbine.

The IGCC technology thus isolates carbon dioxide by adding additional equipment and processes to the power plant, as does oxy-combustion or a carbon dioxide scrubber. The IGCC technology has advantages, in that the carbon dioxide rich gas from the water/gas shift reactor is already at elevated pressure, enabling it to use the physical solvents such as Selexol or Rectisol, rather than the chemical solvents such as amines or chilled ammonia.

Both the physical and the chemical carbon dioxide separation processes use substantial plant steam and auxiliary power to heat the solvent, liberate the carbon dioxide, and regenerate the solvent for re-use. This penalty raises the price of electricity significantly, compared to the base case with no carbon capture.

Evaluation

Financial Model – To compare these technologies on a financial basis, the writers selected a universal financial pro-forma for large power and central power station projects. EconExpert-LP from Competitive Energy Insight, Inc. (CEI), is a sophisticated and highly flexible spreadsheet developed in Microsoft Excel ®[1] to be used for performing financial analysis of all electric power generating projects using virtually any technology type including gas fired, coal fired, petroleum coke fired, wood fired, oil fired, wind, solar or geothermal projects. The power of EconExpert-LP is its flexibility. The user can collect relevant information on a power project through the model's input sheets; specify the conditions of ownership, procurement, construction, financing, fuel supply, operation and electricity sales of virtually any power generation project; and then quickly study how the economic viability of that project might be impacted by changes in market conditions. Built-in menus, automated functions, sensitivities, tornado diagrams, graphics and on-line help features assist in evaluating opportunities and producing reports that clearly and accurately support the conclusions.

The following table illustrates some of the many variables in the pro-forma spreadsheet.

Project Information for Power Plants in EconExpert Spreadsheet Model, with Common Assumptions for the Current Cases

Category	Characteristic
Ownership Type	IOU/Publicly Traded
Location	Eastern Interconnect; plus ERCOT
Coal Type	Bituminous and Sub-bituminous Coal
Plant Capacity, MW	600 MW
GNP Escalation Rate	3%
Base Year	2007
Year of Financial Closing	2007
Construction Term	48 months
Project Life	30 yrs
Capacity Factor (Annual)	85%

Input Variable	Assumption
Discount rate for leveraged NPV	8%
Discount rate for unleveraged NPV	6%
Owner's interest in the project	100%
Major maintenance frequency	7 years
Capacity factor in major maintenance year	80%
Months of fuel supply in inventory	3 months
Salvage value (% of capital)	10%
Interest rate on construction financing	8%
Annual interest rate on senior debt	8.5%
Federal Income Tax rate	34%
Capital Gains federal income tax rate	15%
Property Tax Factor	1%
Insurance Factor	1%

Price and Cost Forecasts – For equipment and operating costs, the writers used the "*Cost and Performance Comparison of Fossil Energy Power Plants,*" DOE/NETL-401/053106, especially Volume 1, "Bituminous Coal and Natural Gas to Electricity" (CPC), and the report on "*Oxyfuel Combustion Systems Analysis Study*" (OCSA). These are Class 4 estimates, in the terminology of the American Association of Cost Engineering, that is, they are parametric or budgetary level estimates. However, the specifics of the plants are spelled out to a Class 2 level of detail, including the mass balance, equipment list and costs, both capital and expense, for the new technologies. For the IGCC cases, the oxygen-blown, slurry-fed, entrained flow gasifier was used. Capital costs were adjusted for all units to 600 MW, to match the standard size of the Integrated Coal Gasification Combined Cycle plant, using industry-standard scaling factors. For the Combustion cases, conventional supercritical conditions were 3,500 psig / 1,100 F/ 1,100 F, and ultra supercritical conditions were 4,000 psig / 1,350 F / 1,400 F.

Case	**Selected Key Assumptions for Economic Evaluation Process (Part 1)** Description	Capacity MW	Net Plant Heat Rate Btu/kW-hr.	Capital Invest-ment $/kW	Source of Estimate
1	Conventional supercritical w/out Carbon Management	600	8,858	$1,319	CPC
2	IGCC Without Carbon Management	600	8,832	$1,586	CPC
3	IGCC With Carbon Management (Achieved Availability)	600	10,463	$1,913	CPC
4	Conventional supercritical with Oxy-fuel	600	12,034	$2,340	OCSA
5	Conventional supercritical with Oxy-fuel	600	11,965	$2,379	OCSA
6	Conventional supercritical with Oxy-fuel	600	12,030	$2,365	OCSA
7	Ultra supercritical with Oxy-fuel	600	10,300	$2,267	OCSA
8	Ultra supercritical with Oxy-fuel	600	10,332	$2,349	OCSA
9	Supercritical with CO2 Scrubber MEA	600	15,323	$2,344	CPC
10	Supercritical with CO2 Scrubber KS-1	600	12,577	$1,924	Author
11	Supercritical with CO2 Scrubber AC	600	11,160	$1,900	Author

Case	**Selected Key Assumptions for Economic Evaluation Process (Part 2)** Description	Variable O&M Cost $/MW-hour	Fixed O&M Cost $/kW-year	Capacity Factor	O2 Purity
1	Conventional supercritical w/out Carbon Management	$6.80	$21.19	85%	
2	IGCC Without Carbon Management	$6.32	$82.00	85%	
3	IGCC With Carbon Management (Achieved Availability)	$7.84	$97.00	80%	
4	Conventional supercritical with Oxy-fuel	$5.90	$32.65	85%	95%
5	Conventional supercritical with Oxy-fuel	$5.90	$32.73	85%	99%
6	Conventional supercritical with Oxy-fuel	$5.90	$32.81	85%	EOR
7	Ultra supercritical with Oxy-fuel	$5.40	$32.35	85%	95%
8	Ultra supercritical with Oxy-fuel	$5.60	$33.04	85%	EOR
9	Supercritical with CO2 Scrubber MEA	$13.30	$30.08	85%	
10	Supercritical with CO2 Scrubber KS-1	$10.77	$30.08	85%	
11	Supercritical with CO2 Scrubber AC	$8.97	$30.08	85%	

For estimates of the price of electricity and the cost of fuels, the writers used recent studies from the U.S. Department of Energy, including the supplemental regional forecasts from the Energy Information Administration's "*Annual Energy Outlook 2006*", to define the business environment in four (4) representative regions of the country, to the year 2030. See Charts 1 and 2 for the price of electricity and coal in constant dollars to 2030. For years beyond 2030, the data for the last year with a forecasted value was straight-lined to the end of the planning period.

Metrics – The goal that management sets, and the way that goal is measured, can make a difference in the operation of a power plant. Many comparisons of generating technologies use the "Cost of Electricity"

(COE) as the best way to compare different generating technologies. The Babcock & Wilcox Company often works with the owners of the power plants, who are in the business of generating electricity. For these owners, "Cost of Electricity" is only part of their objective. Whether or not the power plant is subject to price regulation, the owners aim to recover their full costs, including the cost of capital. The owners also aim to make an economic profit, in addition to covering their costs. B&W's customers often judge the success of a power plant by whether it provides a positive Net Present Value (NPV) and whether the project's Internal Rate of Return (IRR) meets their goals for such a large capital investment.

In this context, Net Present Value (NPV) means the value today of a stream of receipts minus expenditures over time in the future, converted to the present using an interest rate. If X_t is the amount in period t and r the interest rate, then present value at time t=0 is $V = \Sigma_t (X_t)/ (1+r)^t$.

Similarly, Internal Rate of Return (IRR) is a way to compare the profit to the amount invested. It is expressed as a percent gain or loss, for easy comparison with other percent changes for the same time period. More specifically, it is the interest rate at which an investment's future cash inflows, discounted back to today, equal its current and future cash outflows. IRR is an alternative method of evaluating investments without estimating the discount rate. The IRR and NPV concepts are related but they are not equivalent.

These measures of performance are as important as, or more important than, the cost of electricity. Therefore, we have compared these projects on the basis of Net Present Value and Internal Rate of Return.

Results:

With the assumptions described above and the cases drawn from the Department of Energy Reports, the EconExpert financial spreadsheet was used to calculate returns. Rankings for the Mid Atlantic Area Council (MAAC) are shown. Chart 1 and 2 at the end use the reference case for the selling price of electricity and the cost of coal from the *Annual Energy Outlook 2006* to define the business environment. The Benchmark cases of a supercritical boiler with no carbon capture, and an IGCC with no carbon capture, topped the list with 11.7% and 10% IRR's, respectively. Among the carbon-management technologies with the most promising results, based on these assumptions, were the:

- Carbon dioxide scrubber using ammonium carbonate as the carbon dioxide solvent at 7.2%
- Ultra-supercritical with Oxy-fuel using 95% Oxygen at 7.1%
- IGCC with carbon management at 7.1 %

Other variations on Oxy-fuel, with different levels of purity clustered close behind. The carbon dioxide scrubbers with the more energy-intensive carbon dioxide solvents showed the lowest rates of return. When adjusted for the risk of long-lived assets, none of these returns are compelling. It is not surprising that we see relatively little construction of new coal-fired power plants in the Mid-Atlantic region (MAAC) today.

		Internal Rate of Return (IRR), *equity financed, 30 year service life*	
Rank	Case	Description	%
1	1	Conventional supercritical w/out Carbon Management	11.7%
2	2	IGCC Without Carbon Management	10.0%
3	11	Supercritical with CO2 Scrubber AC	7.2%
4	7	Ultra supercritical with Oxy-fuel (95% O2)	7.1%
5	3	IGCC With Carbon Management (Achieved Availability)	7.1%
6	8	Ultra supercritical with Oxy-fuel (EOR quality)	6.9%
7	4	Conventional supercritical with Oxy-fuel (95% O2)	5.9%
8	5	Conventional supercritical with Oxy-fuel (99% O2)	5.9%
9	6	Conventional supercritical with Oxy-fuel (EOR quality)	5.9%
10	10	Supercritical with CO2 Scrubber KS-1	5.8%
11	9	Supercritical with CO2 Scrubber MEA	2.6%

Another measure of financial performance, Net Present Value, yields a somewhat different ranking. Using this measure, the benchmark conventional supercritical boiler still ranks first by a wide margin. Both of the IGCC's, with and without carbon management, however, fall down in the rankings. As a measurement, Net Present Value tends to penalize cash outflows in the early years. Looking at the details, it appears that the downtime during the major maintenance outages to replace refractory may cause the IGCC technology to rank lower on Net Present Value, compared to the Internal Rate of Return rankings.

		Net Present Value (NPV) *equity financed, 30 year service life*	
Rank	Case	Description	$000's
1	1	Conventional supercritical w/out Carbon Management	$839,545
2	2	IGCC Without Carbon Management	$265,742
4	7	Ultra supercritical with Oxy-fuel (95% O2)	$227,674
3	11	Supercritical with CO2 Scrubber AC	$212,651
6	8	Ultra supercritical with Oxy-fuel (EOR quality)	$175,609
7	4	Conventional supercritical with Oxy-fuel (95% O2)	($12,594)
8	5	Conventional supercritical with Oxy-fuel (99% O2)	($24,084)
9	6	Conventional supercritical with Oxy-fuel (EOR quality)	($24,795)
10	10	Supercritical with CO2 Scrubber KS-1	($27,789)
5	3	IGCC With Carbon Management (Achieved Availability)	($124,697)
11	9	Supercritical with CO2 Scrubber MEA	($595,524)

The various technologies for carbon management are mixed in their rankings on Net Present Value. No one combustion technology appears to dominate the returns at this early stage of development, and gasification currently is the least attractive. Based on what is known now, it is appropriate to invest in research and development for a range of technologies for carbon management of coal.

All these new technologies are hard-pressed to keep up with the returns from a conventional supercritical power plant without carbon management.

If a power company were to invest in a new plant with expensive carbon management, while none of the other power companies did, then the low-carbon investor would also have a higher price of electricity for sale to the grid. As a result, that low-carbon plant would be dispatched less often. Power companies are not as likely to invest in carbon management technologies until there is assurance that competing power companies will also invest in carbon management technologies, or until incentives encourage it. However, some power companies are pursuing programs which include carbon management. A few are well located, to provide carbon dioxide for enhanced oil recovery (EOR). Others intend to master the technology of carbon management, in preparation for the time when that may be a key competitive competence.

Regional Comparison

Because The Babcock & Wilcox Company was a participant in the study for oxy-combustion the writers can be more detailed in discussing that technology. Using the Department of Energy's Annual Energy Outlook 2006, projections for the selling price of electricity and the cost of coal by region, the following regions were selected to explore a variety of conditions:

Selected Regions of the North American Electric Reliability Council,
by business characteristics which are key for coal power plants,
from DOE *Annual Energy Outlook 2006, Supplement*

Regional Comparison		Cost of Fuel	
		Higher	Lower
Price of Electricity	Higher	MAAC	ERCOT
	Lower	ECAR	SPP

These regions also reflect some of the areas where developers are cultivating coal-fired power plants.

The Net Present Value varies with the profit margin available from the sale of coal-based electricity. Where the selling price of electricity is forecasted to be low and the cost of Eastern bituminous coal is higher, as in ECAR, then the Net Present Value of a billion-dollar investment over 30 years may be only $65 million, if these assumptions match the reality, and only a few coal plants are in development in this region. Conversely, the cost of fuel is lower in the ERCOT region, due to the proximity of sub-bituminous coal from the Powder River Basin (PRB) and local lignite. The selling price of electricity in ERCOT is higher, since natural gas fuels so many of the plants. With low-cost coal and higher-priced electricity, the Net Present Value of the example oxy-combustion unit in ERCOT is over half a billion dollars.

Results vary widely by region
Oxy-fueled Ultrasupercritical unit with carbon management
Net Present Value (NPV), equity-financed, 30 year service life

Regional Comparison		Cost of Fuel	
	$000's	Higher	Lower
Price of Electricity	Higher	$227,674	$570,867
	Lower	$65,473	$105,166

Price Increase Needed to Attract an Investor in Carbon-Controlled Power Plants

It may be worthwhile to consider the ERCOT region from another perspective. How much would the price of electricity need to increase to cover the cost of these example technologies, and still provide to the investor a 15% Internal Rate of Return?

First, consider the benchmark supercritical unit with no carbon management. Over the thirty-year life of this analysis, an average decrease of $6.60 per megawatt hour in the price of electricity in Time-of-Performance dollars would be made possible by the benchmark new plant.

Rank	Case	**Change in Price of Electricity necessary to earn 15% Internal Rate of Return (IRR),** *assuming 40% equity finance, 30 year service life,* **Region: ERCOT Only Selected Technologies, Conventional and Oxy-fuel**	**Net Present Value (NPV)** *At 15% IRR, assuming 40% equity finance, 30 year service life $000's*	**Change in Price of Electricity necessary to earn 15% IRR,** *assuming 40% equity finance, 30 year service life, $/MW-hour*
1	1	Conventional supercritical w/out Carbon Management	$742,250	-$6.60
2	7	Ultra supercritical with Oxy-fuel (95% O2)	$232,928	$11.90
3	8	Ultra supercritical with Oxy-fuel (EOR quality)	$188,669	$13.60
4	4	Conventional supercritical with Oxy-fuel (95% O2)	$66,107	$16.60
5	6	Conventional supercritical with Oxy-fuel (EOR quality)	$55,269	$17.00
6	5	Conventional supercritical with Oxy-fuel (99% O2)	$54,205	$17.10

With carbon management provided by oxy-combustion, the price of electricity would rise by a range of $11.90 to $17.10 per megawatt hour. This provides a hint of how much the price of electricity may need to increase, to cover the cost of an extensive carbon-reduction program. If and when a mandate comes to reduce carbon dioxide emissions, the cost with currently-foreseen technology will be substantial. It would be beneficial to invest in research and development for a balanced portfolio of technologies to reduce the cost of carbon management. The Electric Power Research Institute (EPRI) recently made public the "*Feasibility Study for an Integrated Gasification Combined Cycle Facility at a Texas Site*", commissioned by CPS Energy of San Antonio, Texas. The study concluded that a pulverized coal unit with amine scrubbing was likely to be more economical than an IGCC, partly due to the low rank coals common in that location.

Implications

Because of the immense volumes of carbon dioxide, any program to reduce emissions from the electric power sector will require a balanced mix of renewables, nuclear and fossil fuels. Among the fossil fuels, coal is domestic, reliable and relatively inexpensive. With the large scale of the coal sector, it is impractical to replace coal within the foreseeable future. Methods of managing carbon dioxide from coal are needed.

Coal currently fuels half of all the electricity generated in the United States. At today's prices, it would cost half a trillion dollars to replace the existing stock of coal fired power plants.

The coal fleet will only gradually be replaced. Therefore, it is important to consider whether any of the carbon dioxide control technologies are suitable for retrofit applications. An IGCC unit would replace all but the coal-handling and the switchyard.

If space is available and there is a place to pump the carbon dioxide, a carbon dioxide scrubber may fit, although with a significant penalty in steam for regenerating the carbon dioxide solvent.

Where oxy-combustion with recirculated flue gas (mostly carbon dioxide) operates in the same design regime as the original boiler, it may be possible to replace the air-fuel mixture with oxy-fuel, although with a significant penalty in auxiliary power for the Air Separation Unit. B&W prepared a conceptual design to repower an existing 22MWe boiler at the City of Hamilton, Ohio, under a contract with the U.S. Department of Energy.

Further development of these retrofitable technologies would add flexibility to the industry's response to any future requirement to manage carbon.

Conclusion

The economic performance of these alternative technologies for carbon management is roughly similar. All are probably early in their life cycle, considering the potential scale of the carbon dioxide issue. Because carbon dioxide is a public issue, not an issue unique to selected companies, it is appropriate for governments and stakeholder institutions to share in the cost of research, development and deployment of these technologies.

There is a realistic plan to address the issue of carbon management in the electric power sector. Many stakeholders have come together in the Coal Utilization Research Council (CURC) and the Electric Power Research Institute (EPRI), to lay out the steps needed to reduce the costs of these technologies for carbon management. They have recently revised this Technology Roadmap to reflect the most pressing priorities. Because the need to manage carbon has only recently become a priority, it is reasonable to expect that additional research will yield many benefits in increasing the effectiveness and reducing the cost of carbon management.

The Technology Roadmap can guide both the industry and the Department of Energy. Priorities for the coal sector include both improvements in IGCC and in Combustion technology. Key parts of the Roadmap will benefit both gasification and combustion technologies, including:

- Low cost carbon capture technologies
- Lower cost oxygen
- Carbon dioxide transport and storage

As we have seen, no one technology dominates the solutions to carbon management of coal. America needs a balanced approach, to provide the country and the industry with the best and most economical solutions available from both gasification and combustion technologies.

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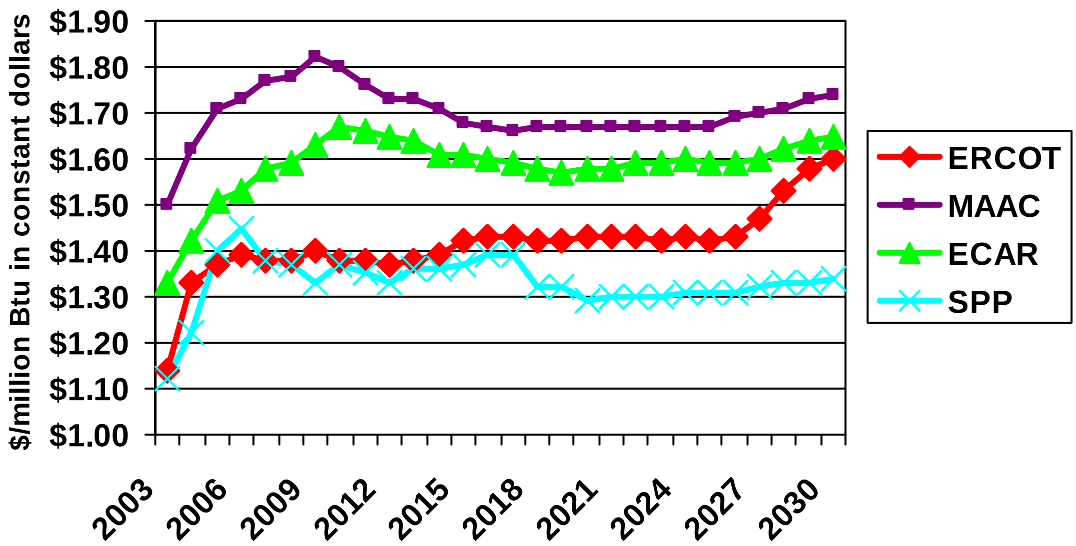
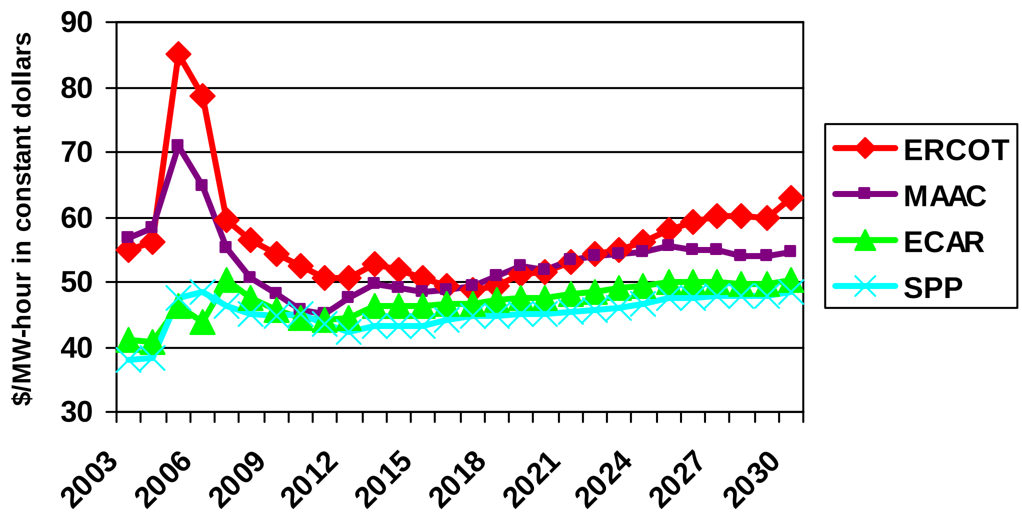
Chart 1



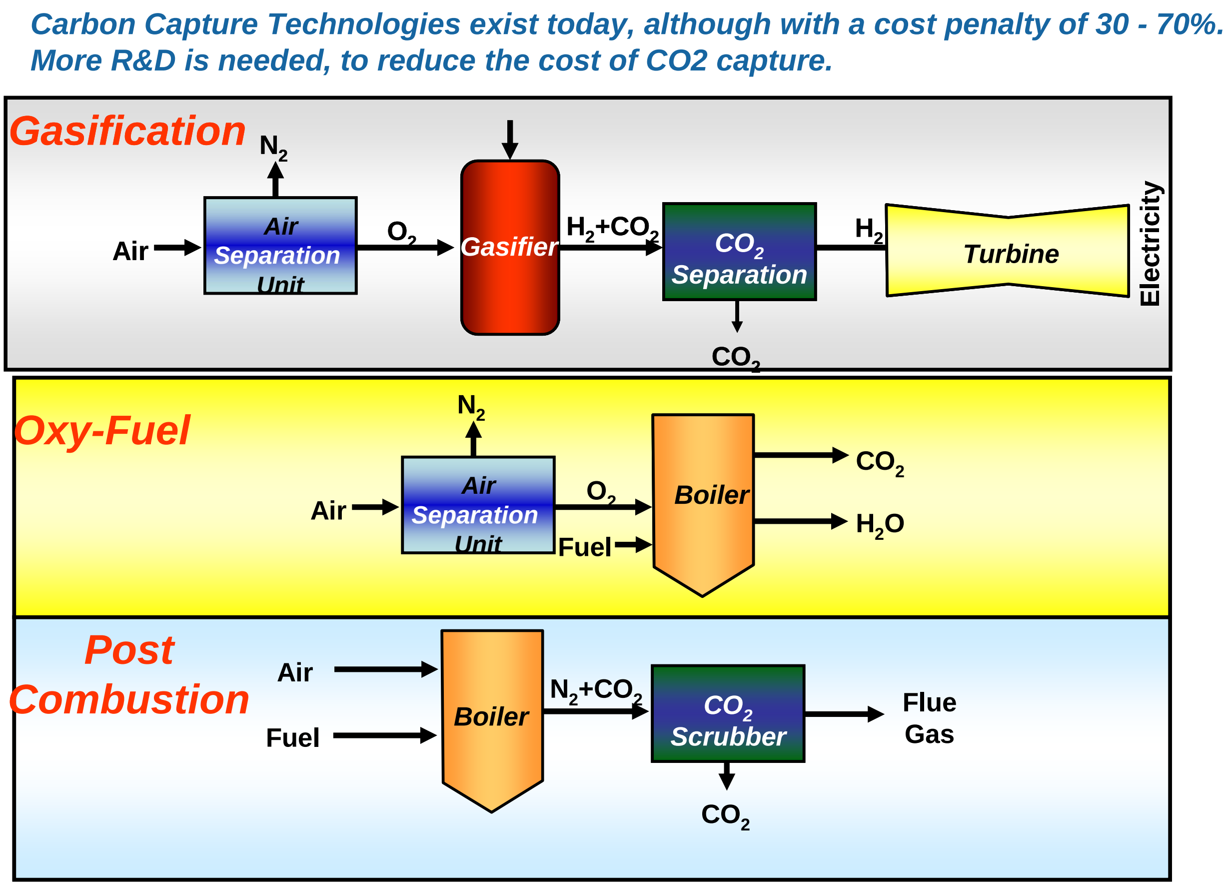
Coal Price, Selected Regions, 2003 – 2030
$/million Btu, in constant 2004 dollars
Source: DOE, EIA <u>Annual Energy Outlook 2006</u>, Regional Supplement

Chart 2



Wholesale Electricity Price, Selected Regions, 2003 – 2030
$/MW-hour in constant 2004 dollars
Source: DOE, EIA <u>Annual Energy Outlook 2006</u>, Regional Supplement

Figure 1 – Carbon Capture Techniques



SIXTH ANNUAL CONFERENCE ON
CARBON CAPTURE & SEQUESTRATION
May 7 - 10, 2007
Pittsburgh, Pennsylvania

Comparison of Environmental Quality, Performance and Economics of Clean Coal Technologies for Carbon Capture

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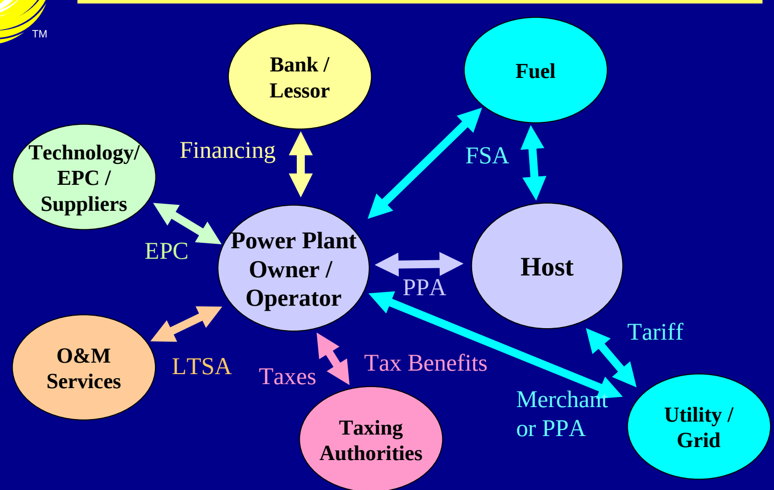
Agenda

- Introduction and Analytical Approach
- Alternatives
- Evaluation
- Results
- Implications

The Foundation of This Analysis

- EconExpert Software
- Financial Model for Analyzing Investments in Power Generation

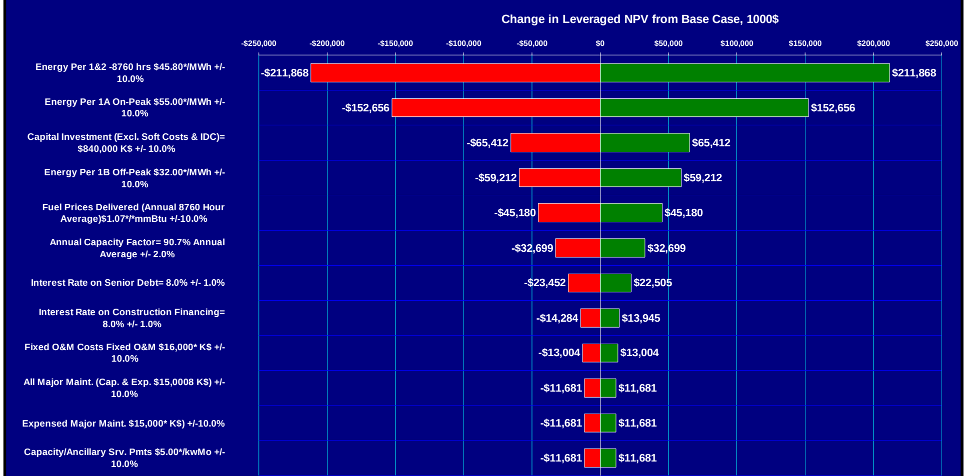
EconExpert Philosopy
The Economics of Stakeholders are Linked



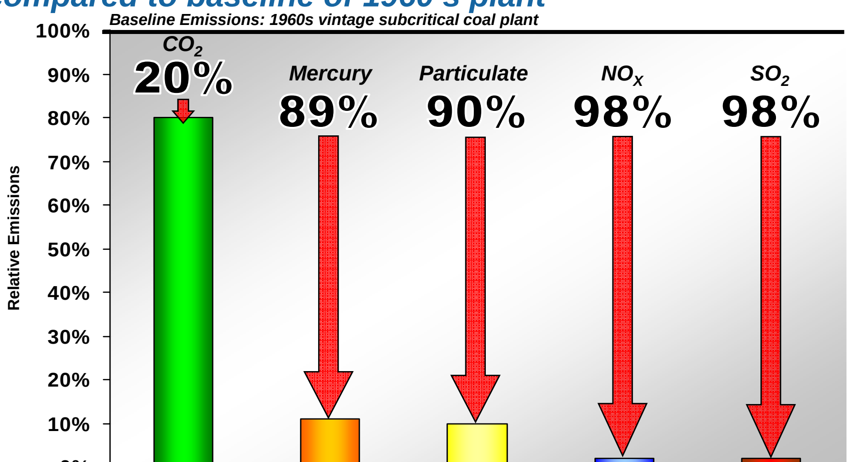
Optimizing the Value Proposition is All About Fully Understanding Your Counterparts Interests!

Sensitivity Analyses Quantify Risks

Consolidated Tornado Diagram - Sensitivity of Leveraged After Tax NPV to Changes in Revenue Related Inputs
Base Case 30 yr. Leveraged NPV= $683,753



New Pulverized Coal Plants Significantly Reduce Emissions, compared to baseline of 1960's plant

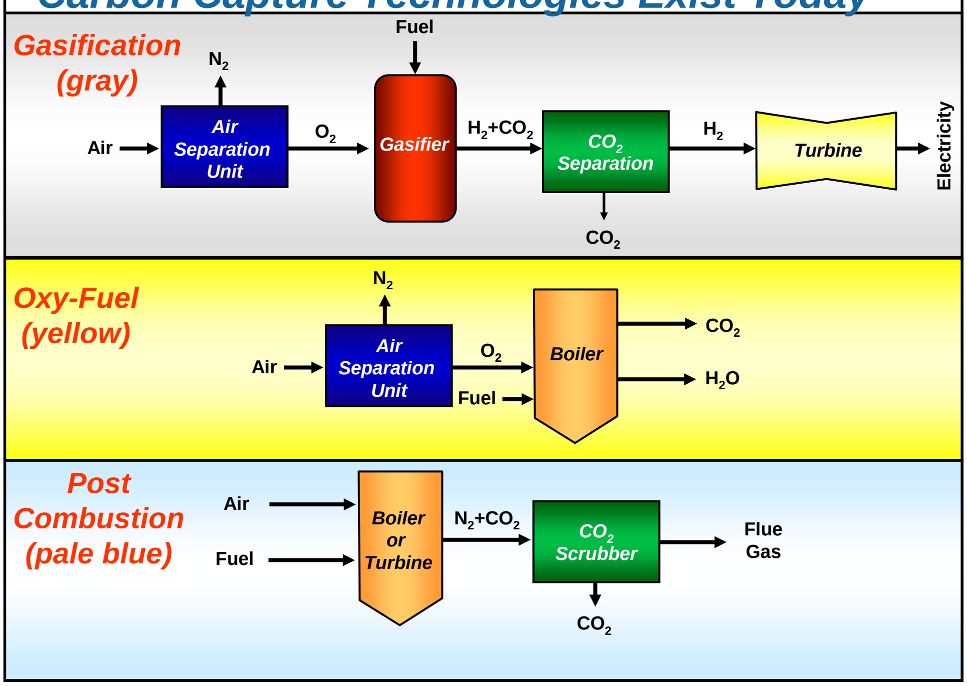


1609.1 lb/MWh	0.06 X 10^{-5} lb/MWh	0.20 lb/MWh	0.39 lb/MWh	0.57 lb/MWh
201.1 lb/MBtu	0.08 X 10^{-3} lb/TBtu	0.025 lb/MBtu	0.05 lb/MBtu	0.07 lb/MBtu
Emissions from new supercritical bituminous coal plants, 2005 – 2015				

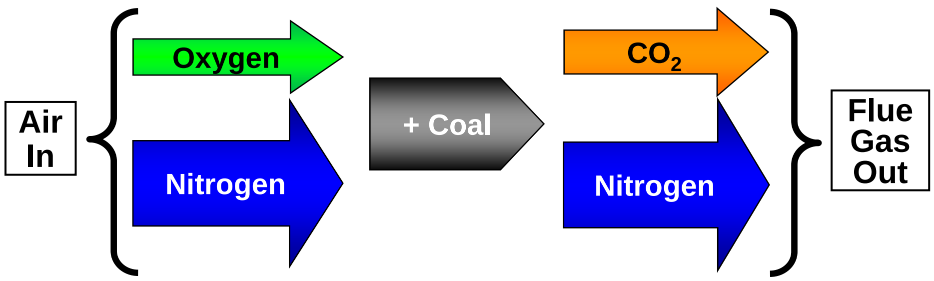
Carbon management is the next challenge

Alternatives for Carbon Capture

Carbon Capture Technologies Exist Today

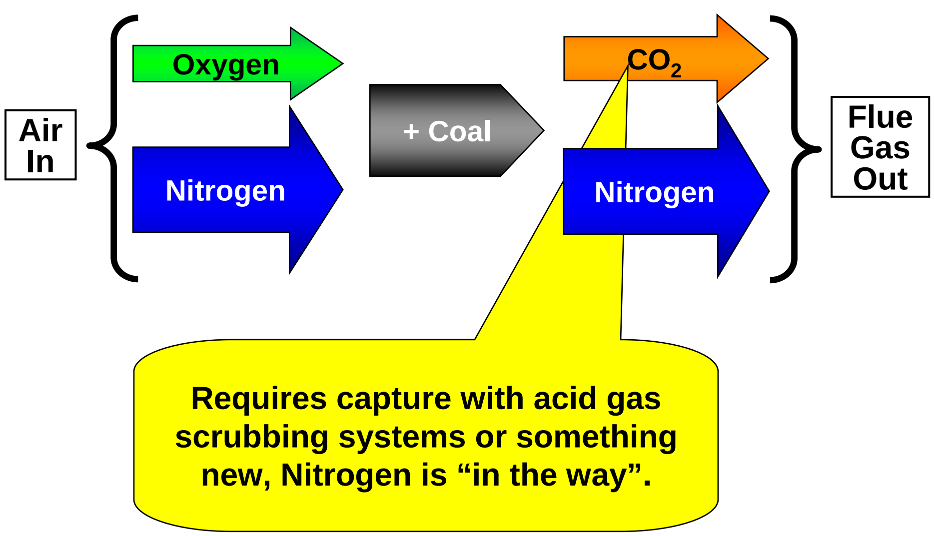


Typical Current Standard Practice: Air Fired Technology

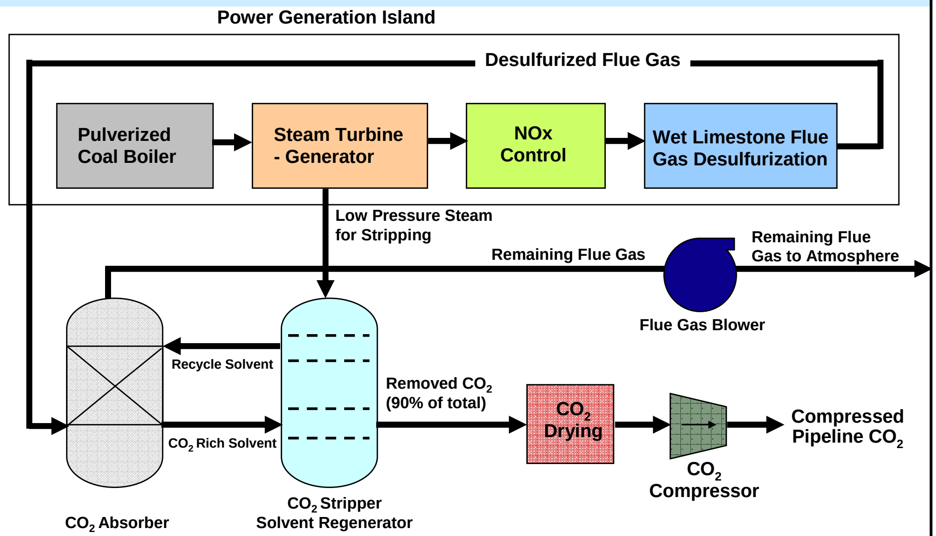


"Air Fired" boilers combine air, (~80% Nitrogen and ~20% oxygen) and coal and discharge products of combustion (flue gas) to the atmosphere.

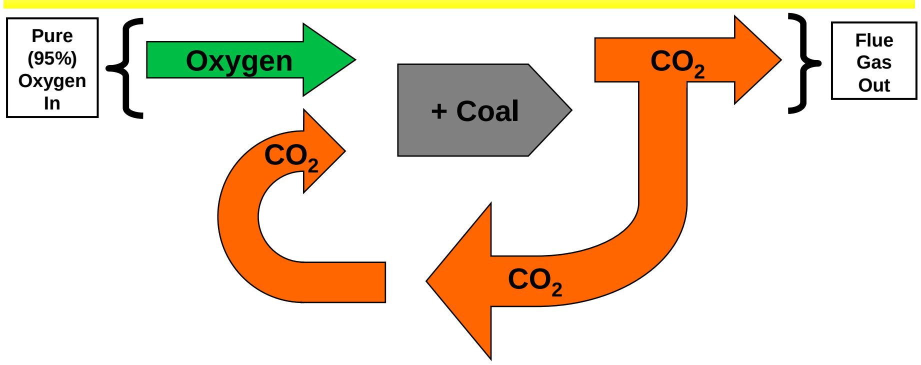
Typical Current Standard Practice: Air Fired Technology



CO_2 Removal by Solvent Absorber/Stripper

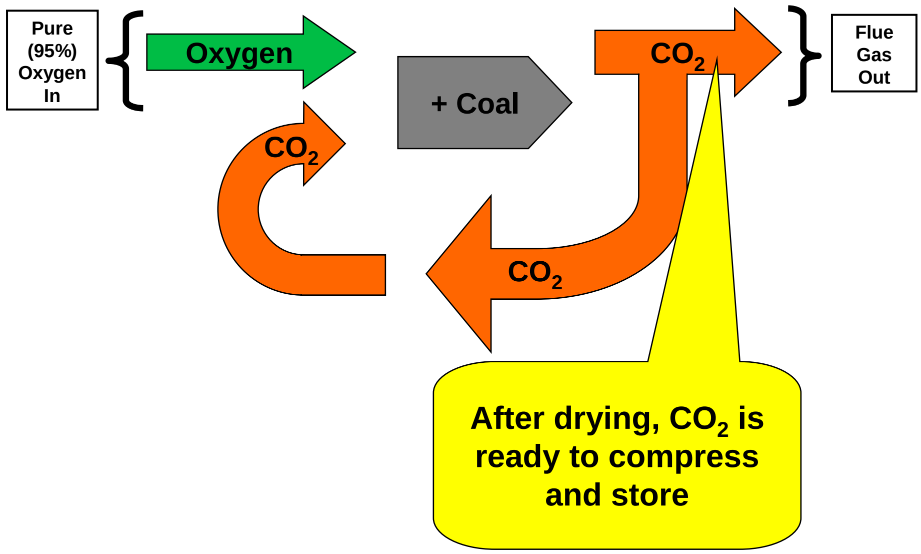


Oxy-Coal Technology

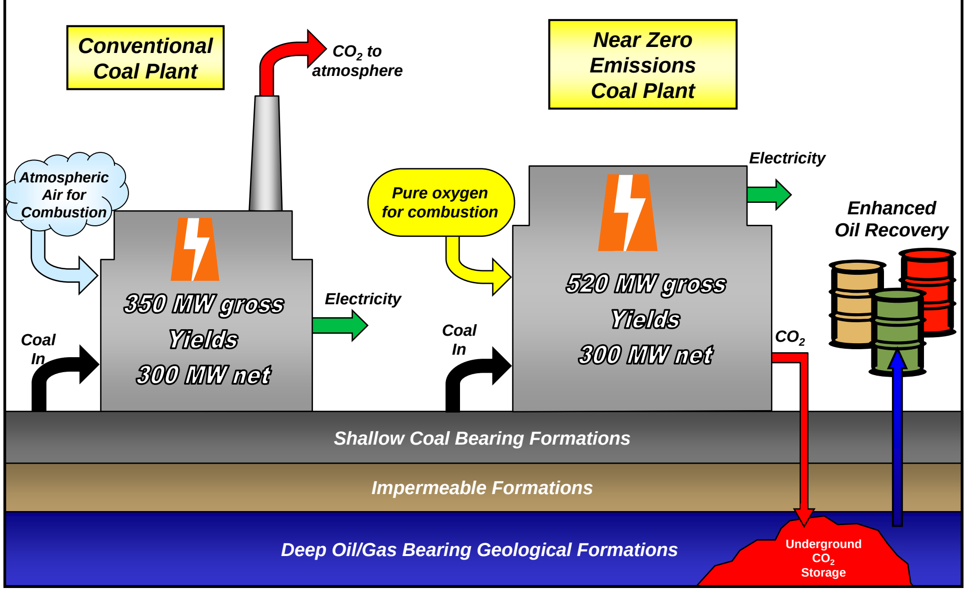


Oxy-Coal technology uses pure oxygen and recycled CO_2 to control the combustion temperature and as a heat transfer medium

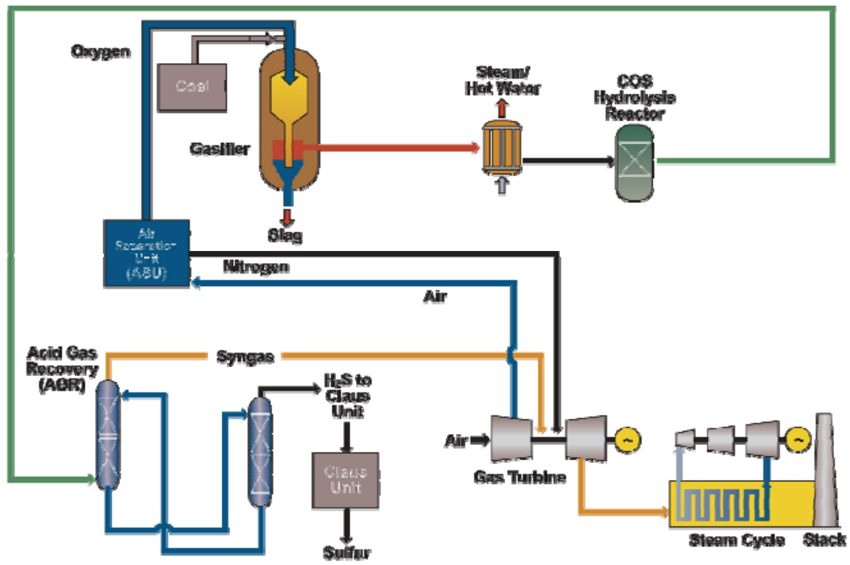
Oxy-Coal Technology



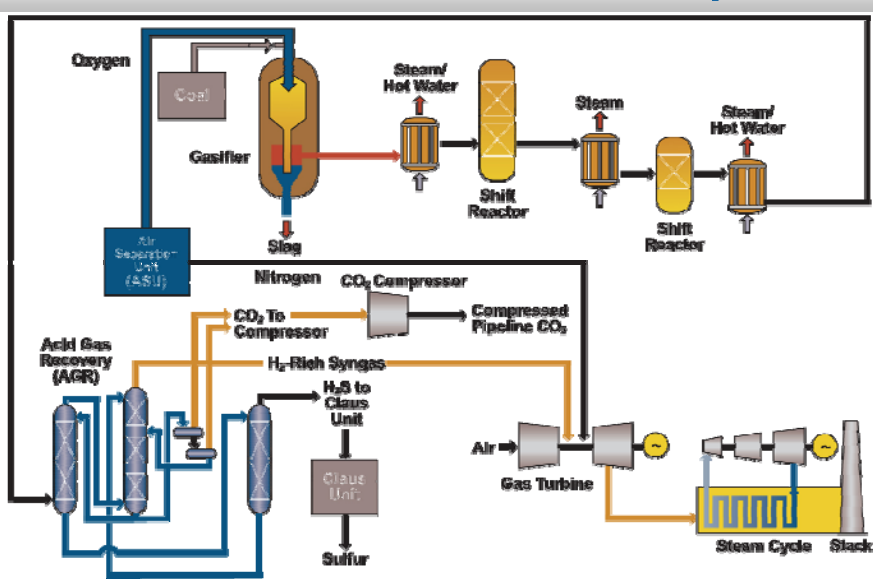
SaskPower Clean co$_2$al Project



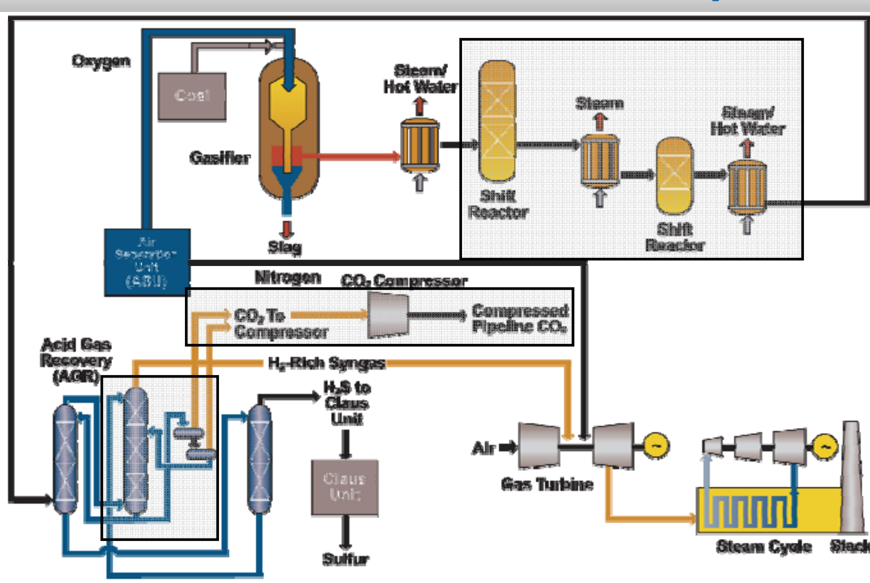
IGCC Without Carbon Dioxide Capture



IGCC With Carbon Dioxide Capture



IGCC With Carbon Dioxide Capture



Evaluation Process

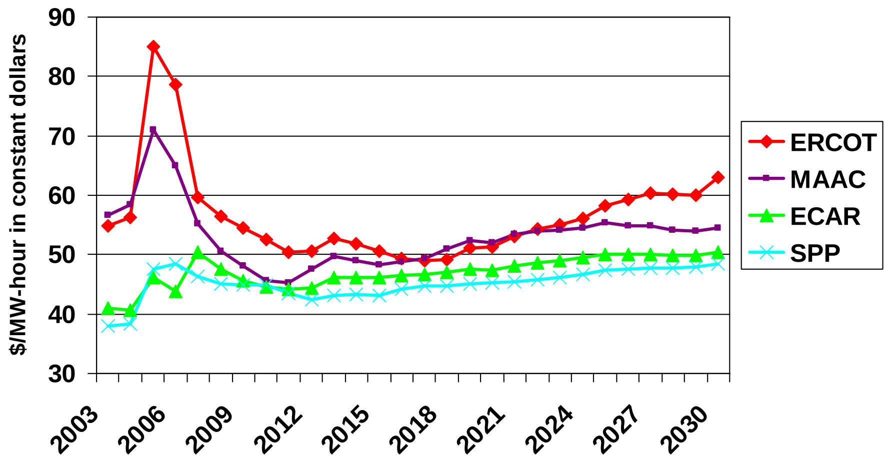
Project Information for Power Plants in EconExpert Spreadsheet Model, with Common Assumptions for the Current Cases

Category	*Characteristic*
Ownership Type	**IOU/Publicly Traded**
Location	**Eastern Interconnect; plus ERCOT**
Coal Type	**Bituminous and Subbitumious Coal**
Plant Capacity, MW	**600 MW**
GNP Escalation Rate	**3%**
Base Year	**2007**
Year of Financial Closing	**2007**
Construction Term	**48 months**
Project Life	**30 yrs**
Capacity Factor (Annual)	**85%**

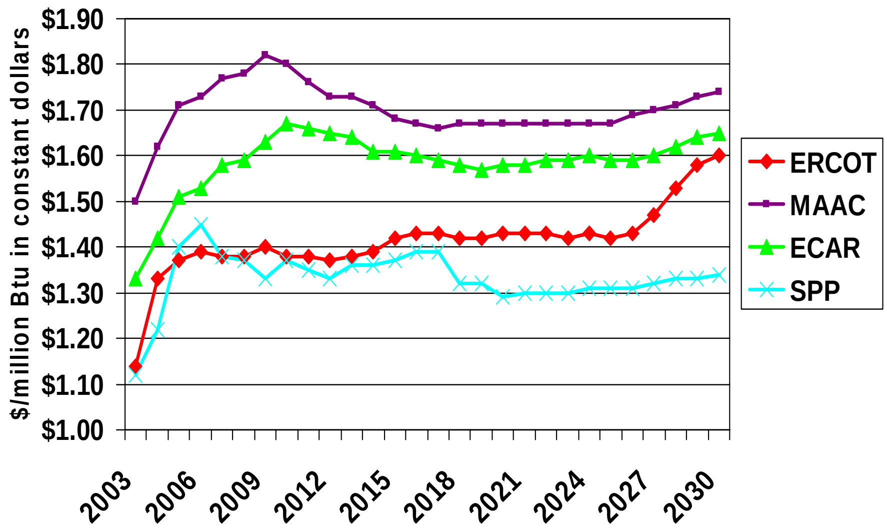
Project Information for Power Plants in EconExpert Spreadsheet Model, with Common Assumptions for the Current Cases (cont.)

Input Variable	*Assumption*
Discount rate for leveraged NPV	**8%**
Discount rate for unleveraged NPV	**6%**
Owner's interest in the project	**100%**
Major maintenance frequency	**7 years**
Capacity factor in major maintenance year	**80%**
Months of fuel supply in inventory	**3 months**
Salvage value (% of capital)	**10%**
Interest rate on construction financing	**8%**
Annual interest rate on senior debt	**8.5%**
Federal Income Tax rate	**34%**
Capital Gains federal income tax rate	**15%**
Property Tax Factor	**1%**
Insurance Factor	**1%**

Wholesale Electricity Price, Selected Regions, 2003 – 2030
$/MW-hour in constant 2004 dollars
Source: DOE, EIA Annual Energy Outlook 2006, Regional Supplement



Coal Price, Selected Regions, 2003 – 2030
$/million Btu, in constant 2004 dollars
Source: DOE, EIA Annual Energy Outlook 2006, Regional Supplement



Selected Key Assumptions for Economic Evaluation Process (Part 1)

Case	Description	Capacity MW	Net Plant Heat Rate Btu/kW-hr.	Capital Invest-ment $/kW	Source of Estimate
1	Conventional supercritical w/out Carbon Management	600	8,858	$1,319	CPC
2	IGCC Without Carbon Management	600	8,832	$1,586	CPC
3	IGCC With Carbon Management (Achieved Availability)	600	10,463	$1,913	CPC
4	Conventional supercritical with Oxy-fuel	600	12,034	$2,340	OCSA
5	Conventional supercritical with Oxy-fuel	600	11,965	$2,379	OCSA
6	Conventional supercritical with Oxy-fuel	600	12,030	$2,365	OCSA
7	Ultra supercritical with Oxy-fuel	600	10,300	$2,267	OCSA
8	Ultra supercritical with Oxy-fuel	600	10,332	$2,349	OCSA
9	Supercritical with CO_2 Scrubber MEA	600	15,323	$2,344	CPC
10	Supercritical with CO_2 Scrubber KS-1	600	12,577	$1,924	Author
11	Supercritical with CO_2 Scrubber AC	600	11,160	$1,900	Author

CPC = Cost and Performance Comparison of Fossil Energy Power Plants, U.S. Dep't of Energy

OCSA = Oxyfuel Combustion Systems Analysis Study , U.S. Dep't of Energy

Selected Key Assumptions for Economic Evaluation Process (Part 2)

Case	Description	Variable O&M Cost $/MW-hour	Fixed O&M Cost $/kW-year	Capacity Factor	O_2 Purity
1	Conventional supercritical w/out Carbon Management	$6.80	$21.19	85%	
2	IGCC Without Carbon Management	$6.32	$82.00	85%	
3	IGCC With Carbon Management (Achieved Availability)	$7.84	$97.00	80%	
4	Conventional supercritical with Oxy-fuel	$5.90	$32.65	85%	95%
5	Conventional supercritical with Oxy-fuel	$5.90	$32.73	85%	99%
6	Conventional supercritical with Oxy-fuel	$5.90	$32.81	85%	EOR
7	Ultra supercritical with Oxy-fuel	$5.40	$32.35	85%	95%
8	Ultra supercritical with Oxy-fuel	$5.60	$33.04	85%	EOR
9	Supercritical with CO_2 Scrubber MEA	$13.30	$30.08	85%	
10	Supercritical with CO_2 Scrubber KS-1	$10.77	$30.08	85%	
11	Supercritical with CO_2 Scrubber AC	$8.97	$30.08	85%	

EOR = Purity sufficient to meet specifications for carbon dioxide used in Enhanced Oil Recovery (EOR)

Results of Evaluation

Internal Rate of Return (IRR),

Equity Financed, 30 Year Service Life

Rank	Case	Description	%
1	1	Conventional supercritical w/out Carbon Management	11.7%
2	2	IGCC Without Carbon Management	10.0%
3	11	Supercritical with CO_2 Scrubber AC	7.2%
4	7	Ultra supercritical with Oxy-fuel (95% O_2)	7.1%
5	3	IGCC With Carbon Management (Achieved Availability)	7.1%
6	8	Ultra supercritical with Oxy-fuel (EOR quality)	6.9%
7	4	Conventional supercritical with Oxy-fuel (95% O_2)	5.9%
8	5	Conventional supercritical with Oxy-fuel (99% O_2)	5.9%
9	6	Conventional supercritical with Oxy-fuel (EOR quality)	5.9%
10	10	Supercritical with CO_2 Scrubber KS-1	5.8%
11	9	Supercritical with CO_2 Scrubber MEA	2.6%

Net Present Value (NPV)

Equity Financed, 30 Year Service Life

Rank	Case	Description	$000's
1	1	Conventional supercritical w/out Carbon Management	$839,545
2	2	IGCC Without Carbon Management	$265,742
4	7	Ultra supercritical with Oxy-fuel (95% O_2)	$227,674
3	11	Supercritical with CO_2 Scrubber AC	$212,651
6	8	Ultra supercritical with Oxy-fuel (EOR quality)	$175,609
7	4	Conventional supercritical with Oxy-fuel (95% O_2)	($12,594)
8	5	Conventional supercritical with Oxy-fuel (99% O_2)	($24,084)
9	6	Conventional supercritical with Oxy-fuel (EOR quality)	($24,795)
10	10	Supercritical with CO_2 Scrubber KS-1	($27,789)
5	3	IGCC With Carbon Management (Achieved Availability)	($124,697)
11	9	Supercritical with CO_2 Scrubber MEA	($595,524)

North American Electric Reliability Council, Selected Regions

by Business Characteristics Which are Key for Coal Power Plants,

from DOE Annual Energy Outlook 2006, Supplement

Regional Comparison			
		Cost of Fuel	
		Higher	Lower
Price of Electricity	Higher	MAAC	ERCOT
	Lower	ECAR	SPP

Results Vary Widely by Region: Oxy-fueled Ultrasupercritical Unit with Carbon Management

Net Present Value (NPV), Equity-financed, 30 Year Service Life

Regional Comparison			
Net Present Value (NPV) $000's		*Cost of Fuel*	
		Higher	Lower
Price of Electricity	Higher	$227,674 MAAC	$570,867 ERCOT
	Lower	$65,473 ECAR	$105,166 SPP

Change in Price of Electricity necessary to earn 15% Internal Rate of Return (IRR)

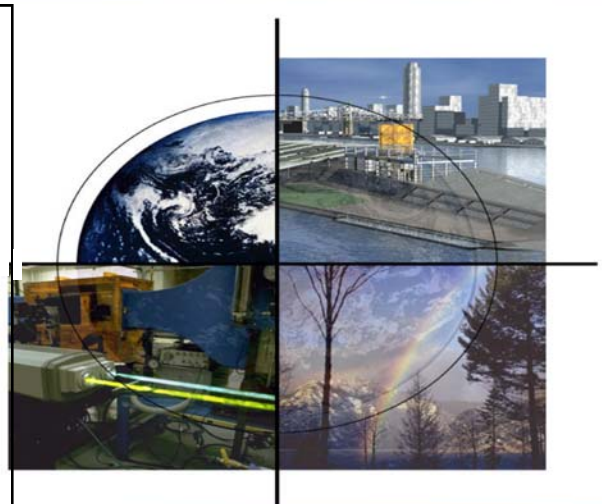
assuming 40% equity finance,
30 year service life,
Region: ERCOT Only
Selected Technologies, Conventional and Oxy-fuel

Rank	Case	Selected Technology	Net Present Value (NPV) $000's	Change in Price of Electricity, *$/MW-hour*
1	1	Conventional supercritical w/out Carbon Management	$742,250	-$6.60
2	7	Ultra supercritical with Oxy-fuel (95% O_2)	$232,928	$11.90
3	8	Ultra supercritical with Oxy-fuel (EOR quality)	$188,669	$13.60
4	4	Conventional supercritical with Oxy-fuel (95% O_2)	$66,107	$16.60
5	6	Conventional supercritical with Oxy-fuel (EOR quality)	$55,269	$17.00
6	5	Conventional supercritical with Oxy-fuel (99% O_2)	$54,205	$17.10

Implications

The CURC-EPRI Roadmap

An industry-agreed path to improved performance for equipment using coal, both gasification and combustion



Electric Power Research Institute,
and the Coal Utilization Research Council

Moving Forward…

North America's energy needs and competitiveness in the world market are best served by a balanced portfolio of clean, efficient technologies and proven strategies

- **Low Emitting Renewables, Hydro, and Nuclear will be important**
- **Coal is still necessary to match the scale of the electricity needed**
- **Continuing R&D is appropriate to improve the efficiency and lower the cost of all the promising alternatives, including carbon dioxide scrubbers, oxy-combustion, and IGCC**

End

IGCC RAM Data – Excludes Impact of Back-up Fuel

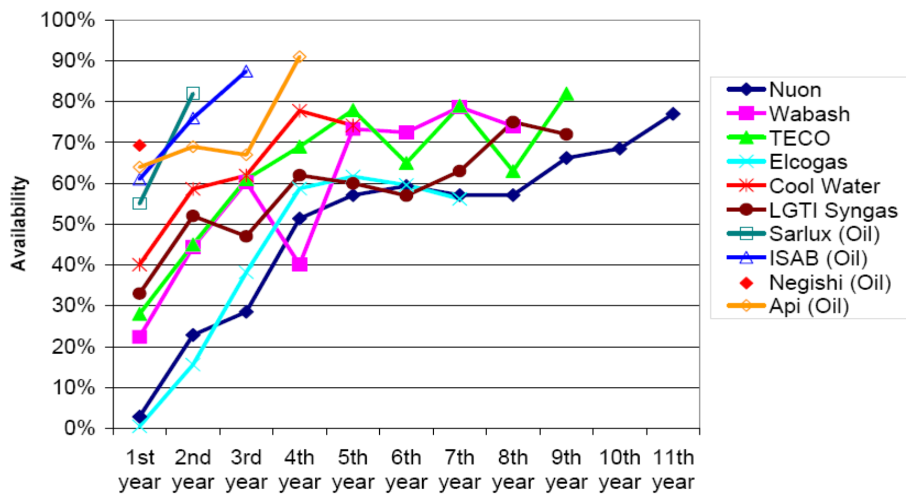


Figure 1 – Availability history of various coal and oil-based IGCCs.

Internal Rate of Return (IRR),

Equity Financed, 30 Year Service Life