Capture-Ready Power Plants - Options, Technologies and Economics

by

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ABSTRACT

A plant can be considered to be capture-ready if, at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate. The concept of capture-ready is not a specific plant design; rather it is a spectrum of investments and design decisions that a plant owner might undertake during the design and construction of a plant. Power plant owners and policymakers are interested in capture-ready plants because they may offer relatively low cost opportunities to bridge the gap between current coal-fired generation technologies without CO_2 capture to future plants that may be built from the start to capture CO_2, and reduce the risks of possible future regulations of CO_2 emissions. This thesis explores the design options, technologies and costs of capture-ready coal-fired power plants.

The first part of the thesis outlines the two major designs that are being considered for construction in the near-term – pulverized coal (PC) and integrated gasification/combined cycle (IGCC). It details the steps that are necessary to retrofit each of these plants for CO_2 capture and sequestration. Finally, for each technology, it provides a qualitative assessment of the steps that can be taken to reduce the costs and output de-rating of the plant after a retrofit.

The second part of the thesis evaluates the lifetime (40 year) net present value (NPV) costs of plants with differing levels of pre-investment for CO_2 capture. Three scenarios are evaluated – a baseline supercritical PC plant, a baseline IGCC plant and an IGCC plant with pre-investment for capture. This analysis evaluates each technology option under a range of CO_2 tax scenarios and determines the most economical choice and year of retrofit. The results of this thesis show that a baseline PC plant is the most economical choice under low CO_2 tax rates, and IGCC plants are preferable at higher tax rates. Little difference is seen in the lifetime NPV costs between the IGCC plants with and without pre-investment for CO_2 capture.

The third part of this thesis evaluates the concept of CO_2 "lock-in". CO_2 lock-in occurs when a newly built plant is so prohibitively expensive to retrofit for CO_2 capture that it will never be retrofitted for capture, and offers no economic opportunity to reduce the CO_2 emissions from the plant, besides shutting down or rebuilding. The results of this analysis show that IGCC plants are expected to have significantly lower lifetime CO_2 emissions than a PC plant, given moderate (10-35 \$/ton CO_2) initial tax rates. Higher (above $40) or lower (below $7) initial tax rates do not result in significant differences in lifetime CO_2 emissions from these plants. Little difference is seen in the lifetime CO_2 emissions between the IGCC plants with and without pre-investment for CO_2 capture.

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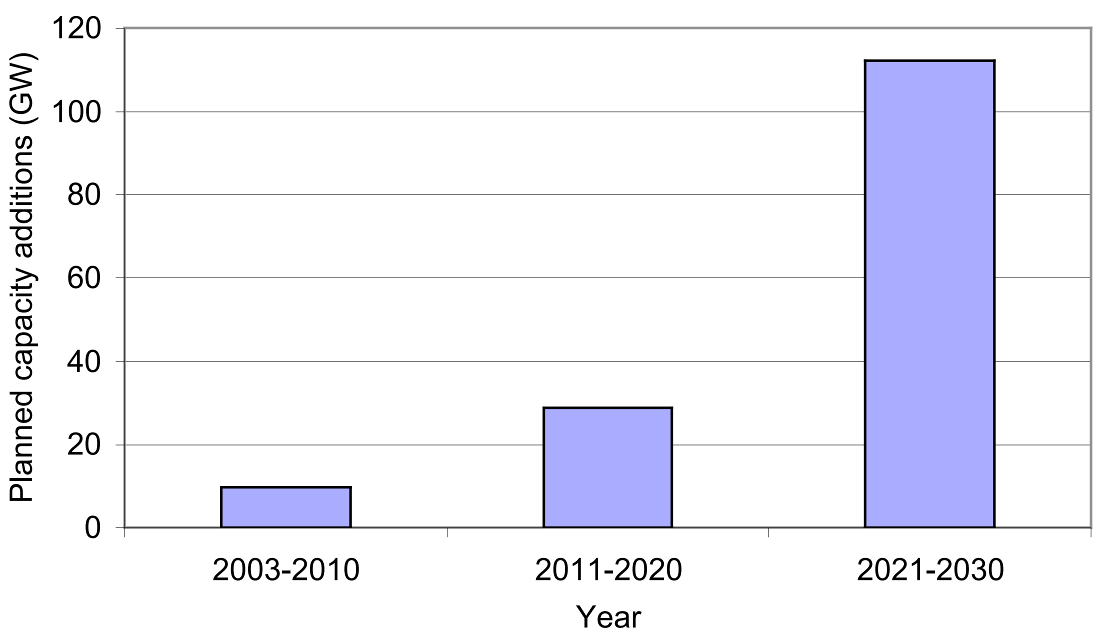
LIST OF ACRONYMS

ASU	Air separation unit
AEP	American Electric Power
AGR	Acid gas removal
BOP	Balance of plant
CC	Carrying charge
CO_2	Carbon dioxde
COE	Cost of electricity
DOE	US Department of Energy
EIA	Energy Information Agency, US Department of Energy
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
ETS	European Trading Scheme
FGD	Flue gas desulfurization
GE	General Electric
GW	Gigawatt
HHV	Higher heating value
HP	High pressure
IGCC	Integrated gasification combined cycle
kW_e	Kilowatt electric
KWh	Kilowatt-hour
LP	Low pressure
MEA	Monoethanolamine
MMBtu	Million British thermal units
MPa	Megapascal
Mt	Megatonne (metric)
MW_e	Megawatts electric
MWh	Megawatt-hours
NCC	National Coal Council
NGCC	Natural gas combined cycle
NPV	Net present value
O&M	Operation and maintenance
PC	Pulverized coal
ppm	Parts per million
SC	Supercritical
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SubC	Sub-critical
TPC	Total plant cost
USC	Ultra-supercritical

1 INTRODUCTION AND SCOPE OF STUDY

Interest in the construction of coal-fired power generation has increased significantly in recent years, sparked by continually increasing demand for electricity, combined with volatile prices of other fossil fuels, including natural gas and oil, the difficulties surrounding the construction of nuclear facilities, and the current challenges of availability and pricing of new generation technologies, such as solar and wind. In the United States, it is expected that overall demand will increase from 3,840 billion kilowatt-hours in 2005 to over 5,600 billion kilowatt-hours in 2030 [EIA 2006]. This correlates into approximately 250 GW of new generation capacity.[1] Of this new capacity, the EIA estimates that 106 GW will be met through the construction of coal-fired plants. This corresponds to an average construction rate of eight 500 MW coal-fired plants per year over the next twenty-five years. Figure 1-1 illustrates the expected growth of coal-fired power plants over the next 25 years.

Figure 1-1 **Forecasted United States coal plant additions by decade, 2003-2030 [EIA 2006]**



[1] Assumes an 85% capacity factor for new plants

Worldwide, the expected installed capacity of coal-fired plants is expected to increase by over 40% in the next 20 years, and by 2025 it is expected to exceed 1400 GW of installed capacity [EIA 2005].

While coal-fired power plants offer significant cost and energy security advantages, they are also major sources of criteria air pollutants such as NO_X and SO_2, air toxics such as mercury, and greenhouse gas emissions, namely CO_2. With an expected lifespan of 40 years or more these plants will account for a significant portion of future global rises in greenhouse gas concentrations if no actions are taken to capture the CO_2 from them. This issue is compounded by the fact that the large majority of both existing and proposed plants are expected to be prohibitively expensive or technically infeasible to retrofit for CO_2 capture and sequestration at a later point [MIT 2006]. This problem can be addressed if, during the initial design and construction phase, the plant is designed to be 'capture-ready', which this study defines as follows:

A plant can be considered 'capture-ready' if, at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate.

The concept of 'capture-ready' is not a specific plant design; rather it is a spectrum of investments and design decisions that a plant owner might undertake during the design and construction of the plant. Further discussion of the range of 'capture-ready' options is discussed in a later section. If carbon prices are high enough it is expected that any plant will be more economical to retrofit than to operate. It is also expected that, in the event that a plant has an overly large output de-rating and increase in operating costs (including fuel), it would be more economical to decommission the plant and build a more efficient plant in its place.

Policymakers have identified the concept of capture-ready power plants as a possible tool to mitigate the long-term emissions of greenhouse gasses. This was recognized by members of the G8 nations at the 2005 Gleneagles Conference on clean energy and sustainable development. In their plan of action, released at the conclusion of the conference, the members identified that the "acceleration of the development and commercialization carbon capture and storage technology" should be pursued by "investigating the definition, costs and scope for 'capture-ready' plants and the consideration of economic incentives" [G8 2005]. Gaining a better understanding of what appropriate steps to build capture-ready plants is a priority to members of the G8 because new power plant installations will be around for decades to come. In addition, plants that are not designed to be 'capture-ready' could prove to be prohibitively expensive to retrofit in the future, resulting in either delayed reductions in CO_2 emissions, or stranded generation assets.

From an owner perspective, the technology choice is driven primarily by economics. The uncertainties surrounding the additional costs and actions required to build a capture-ready facility and the uncertainty surrounding retrofit costs are expected to be significant barriers to its adoption. Added to the uncertainty of upfront capital and future retrofit costs are the uncertainties of future carbon tax levels and growth rates. In the case of a privately financed and owned plant, each of these variables increases the uncertainty of future cash flows, which increases the required investment return and the project hurdle rate for the proposed plant.

1.1 Options for reducing CO_2 emissions from fossil-fuelled power plants

Several options are available to power plant owners to reduce emissions from these plants, each having different investment and performance trade-offs. For coal, these options include:

- The construction of high-efficiency plants. This includes IGCC with advanced heat recovery, or ultra-supercritical PC plants, reducing the emissions of CO_2 per MWh up to 40% as compared with the average existing coal-fired power plant[2].

[2] Assumes a fleet average efficiency of 33%, new build efficiency of 46% (HHV)

- The construction of plants now with carbon capture and sequestration technologies, reducing emissions of CO_2 per MWh by up to 90%.
- Rebuilding of existing plants at some point in the future to capture CO_2 emissions, or to use less CO_2-intensive fuels such as natural gas, or CO_2-free technologies such as nuclear, wind or hydro.
- The construction of capture-ready coal-fired power plants, which accommodations are made during the initial design phase to reduce the cost and performance penalty of retrofitting CO_2 capture at a later date.

This thesis attempts to describe the options, technologies and economics of the final option - capture-ready coal-fired power plants.

1.2 Scope of this study

For plant owners and investors, the two questions surrounding the construction of capture-ready coal-fired power plants are:

- What are the range of actions and investments that can be made during the design and construction of a plant to reduce the future costs and energy penalties of retrofitting for CCS?
- Do these investments and actions make economic sense, given current understandings and uncertainty of future regulations on CO_2 emissions?

Policymakers and regulators, in addition to the above questions, are also interested in the following:

- What role, if any can capture-ready plants play as a transition step towards the long-term reduction of CO_2 emissions from the power sector?
- Will capture-ready plants have an impact on the political feasibility of moving towards reducing CO_2 emissions from the power sector?

- Is there a role for investments in capture-ready technologies in developing nations by international agencies, such as the World Bank?

This thesis attempts to address these issues in two sections. The first section defines the technologies and options for capture-ready plants by exploring the capital and technical requirements for capture-ready for both traditional pulverized coal (PC) and integrated gasification and combined cycle (IGCC) power plants. The second part of this thesis develops a methodology to determine under which scenarios would it be economically efficient to build a capture-ready plant. It also applies the methodology to a number of technology options, and determines what the impacts of the technology selections are on lifetime costs and CO_2 emissions of each case. It also evaluates the concept of CO_2 "lock-in", which occurs when a newly built plant is so prohibitively expensive to retrofit for CO_2 capture that it will never be retrofitted.

1.2.1 Capture-ready plants – definition, technologies and costs

Although it may be technically possible to retrofit any coal-fired power plant for CO_2 capture and sequestration, those that require a very significant investment to retrofit, or sustain an overly large penalty on the plant's net generating output may prove uneconomical to justify a retrofit. Owners of these plants may decide to rebuild the plant and replace the major components such as the boiler and steam turbines with either higher efficiency units (such as ultra-supercritical boilers and high efficiency turbines) or a completely new generating technology such as an IGCC plant with carbon capture and storage (CCS) or a natural gas combined cycle (NGCC) plant. In either case, the owner will incur significant costs in stranding the existing assets that otherwise would have continued operating and producing electricity, possibly for several more decades.

Given the current best estimates of capture performance and costs, it is expected that most of the existing fleet of traditional pulverized coal (PC) generating units in the United States, currently over 300 GW of generating capacity will not be suitable candidates for CCS retrofit [EIA 2005, MIT 2006]. It is possible that new capture and separation technologies may be developed, such as aqueous ammonia or ITM oxygen separation, but significant hurdles still exist in their development, and it is very likely that action will need to be taken to control CO_2 emissions before they are ready for commercial deployment.

Capturing CO_2 from existing natural gas and oil plants may be even less attractive, because of their already lower CO_2 emissions per MWh, lower flue gas concentration of CO_2, along with their lower capacity factors and smaller per kW_e initial investment. Clearly, coal-fired plants are of more interest.

CO_2 capture from power plants will not be done unless there are clear incentives for power plant owners to take action, either through taxes (such as a carbon tax) or through regulation (such as a cap and trade scheme). Power plant owners have been required to reduce emissions in the past, however. Sulfur dioxide (SO_2) emissions in the United States have been restricted by a cap and trade system, which allocates a certain amount of total permitted amount of SO_2 emissions for all plants. Plants are allocated permits based on a percentage of their previous year emission levels, and then are able to buy or sell their permits, depending if the value of the permits exceeds or not the value of the electricity sales the plant would otherwise need to forgo. This system has been very effective, reducing SO_2 emissions by 50% since 1980, with prices of the permits fluctuating between 70 and 210 \$/t SO_2 between 1995 and 2004 [EPA 2006]. The costs of the permits are much lower than what many power companies were predicting when the trading system was first proposed, and the cost savings have been driven by a combination of reduced capital costs of SO_2 control equipment, as well as through the use of low-sulfur coal. Many policymakers have suggested that the same trends could be seen in the control of CO_2 emissions.

1.3 Definition of a 'capture-ready' power plant

As defined in the beginning of this chapter, a plant can be considered 'capture-ready' if, at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate. Given that this existing coal-based fleet appears to be unsuitable for retrofitting CCS without significant leaps in capture technologies, it is important to evaluate and understand the steps that can be taken to ensure that any fossil fuelled power plant built in the future is capture-ready. This is especially important as it is estimated that over 80 GW of coal-fired power generation will be installed over the next two decades in the United States [EIA 2005a]. Power plant owners and policymakers want to understand if investing in capture-ready technology makes sense as an intermediary step as we move towards ever more stringent controls on greenhouse gas emissions.

These investments, if made wisely, will act to reduce the costs that owners will assume in order to comply with future CO_2 regulations, and could also accelerate the rate at which CO_2 capture is adopted, reducing total cumulative emissions. In order for a power plant to be considered capture-ready, technology choices, plant layout and location decisions are made in the initial design and construction to reduce the costs and performance penalties associated with retrofitting the plant for carbon capture and sequestration at some point in the future. The number of actions and level of investment can vary significantly because the level of capture-readiness and technology choices that an owner will decide to employ depends on a number of issues, including:

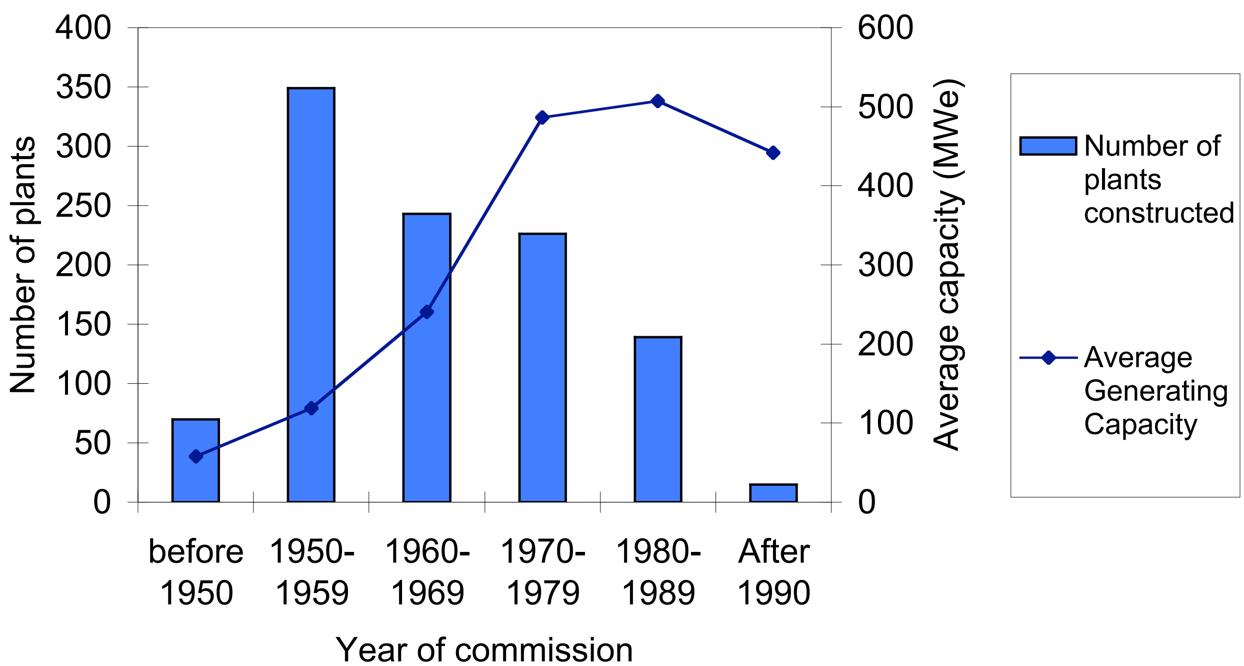
- The investor's choice of a project hurdle or discount rate
- Expectation of the timing and stringency CO_2 regulations and/or taxes
- Ability to recover investment costs at a future date (such as in a regulated market)
- Owner's level of comfort with new, unproven technologies
- Cost and quality of available coal
- Availability and cost of CO_2 transportation and appropriate sequestration sites

The following two chapters describe in detail the options and technologies for both pulverized coal and IGCC coal-fired power plants.

2 PULVERIZED COAL PLANTS

The vast majority coal-fired power plants built to date in the world are pulverized coal steam generation units, and it is expected that this technology will be the predominant choice for the construction of new coal-fired plants in the near term. There are currently 1,526 pulverized coal plants in the United States, with an average size of 220 MWe, and an average operating efficiency of 33% [EIA 2006]. The average age of these plants is 40 years old, with the oldest unit still in service constructed in 1935. The mean generating capacity of each plant increased approximately 8 times from the 1950's to the 1970's, then leveled off. The bulk of the capacity was built in the 1960's and 1970's, with construction tapering off in the 1980's. Very little construction of new coal-fired power plants has occurred in the past 25 years. Figure 2-1 illustrates the range of ages and average generation capacities of coal-fired plants still in operation in the United States.

Figure 2-1 Year of construction and average size of coal-fired power plants in the US [EIA 2006]



2.1 Pulverized coal technology

Pulverized coal plants produce electricity by first producing high pressure, high temperature steam in a large water wall boiler that is fired by pulverized coal and air. The steam produced in the boiler is then piped to a Rankine cycle steam turbine that drives a generator to produce electricity. Depending on the design, the boiler might have between one and three reheat cycles that reheat the steam leaving a higher-pressure stage of the turbine, returning the steam to a lower-pressure stage. Once the steam has finished passing through the turbines it is then condensed to liquid water in a condenser and returned to the boiler to complete the cycle.

Performance improvements for PC plants have generally come from increasing the temperature and pressure of the steam produced by the boiler, which increases the thermodynamic efficiency of the system. Reheat cycles can also be added that heat the steam between higher and lower pressure sections of the turbine, further increasing the power output and efficiency of the boiler. Older style boilers, known as subcritical boilers, do not heat the water beyond the supercritical point of water in the boiler; rather a separate flashing tank is used to produce the steam after the heated water has left the boiler. Supercritical and ultra-supercritical plants heat and pressurize the water beyond the supercritical point (above 22.1 MPa), negating the need for a separate flashing stage before the water is sent to the turbine. These types of plants are able to do this because of recent developments in higher strength materials and better process controls that allow for higher steam temperatures and pressures. Table 2-1 outlines the operating pressures, temperatures and the operating efficiencies of current sub-critical, supercritical and ultra-supercritical PC plants. These values are typical only; the efficiency of the plants depends on a number of factors, including coal quality, condensing cycle type and water temperature (if water cooled), number of re-heat cycles in the turbine, size of the plant, and elevation of site.

Table 2-1 Operating conditions and efficiencies of PC plants

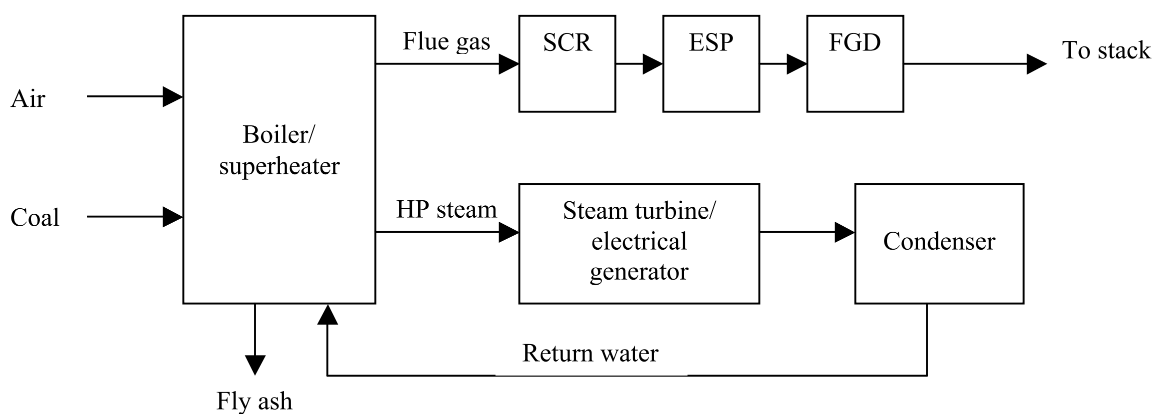
Steam cycle	Pressure (MPa)	Temperature (°C)	Efficiency (%, HHV)
Sub-critical	16.5	540	36 - 38
Supercritical	24.1	565	39 - 41
Ultra-supercritical	31.0	595	43 - 45

The flue gas, after having exited the boiler, is treated to control emissions of certain criteria air pollutants. This treatment usually involves a three-part process, depending on the level of pollutant control required. The plans for new build plants include the following three flue gas cleanup steps.

- Selective catalytic reduction (SCR) for NO_x control
- Particulate removal with an electrostatic precipitator (ESP)
- Flue gas desulfurization (FGD) for sulfur dioxide removal

Figure 2-2 illustrates a simplified process flow diagram for a typical pulverized coal-fired power plant, and outlines the major components.

Figure 2-2 Simplified process flow diagram of a pulverized coal steam generation power plant

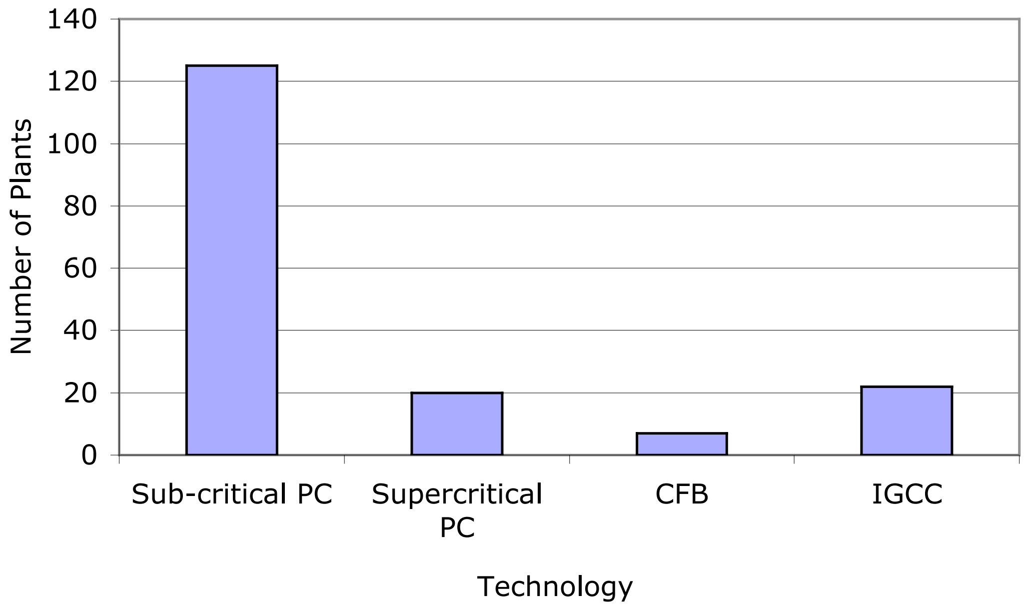


Pulverized coal plants offer a number of advantages over more advanced coal-fired generation technologies, namely IGCC, outlined in Section 4. These advantages include:

- Lower capital costs and risk of cost overruns during the construction phase because of the proven track record of these plants, having been constructed over the past 70 years.
- Lower operation and maintenance costs
- Long track record of high reliability and plant availability
- Ability to use a wide range of coal qualities without significant modifications to the plant
- Ability for existing operators to use current staff expertise in operating these facilities

It is because of these advantages that most of the proposals for new construction of coal-fired plants in both the US and elsewhere in the world are of the traditional pulverized coal design. NETL has reported that 75% of the 87 GW of new coal-fired capacity that will be installed in the next 20 years will be of the pulverized coal variety [NETL 2005]. Figure 2-3 illustrates the expected breakdown of these additions by technology, and the vast majority of these plants are expected to be of the subcritical pulverized coal variety.

Figure 2-3 Forecasted coal plant additions by technology, 2005-2025 [NETL 2005]



The costs and performance of pulverized coal plants have been estimated in a number of recent studies. It is important to note that the capital costs in these reports do not reflect the recent significant increase in fuel and steel costs.

Table 2-2 summarizes the major US studies that have evaluated the costs and performance of pulverized coal technologies for sub-critical, supercritical and ultra-supercritical PC plants.

Table 2-2 Survey of performances, costs and efficiencies for PC generation technologies

Study	MIT 2006	NETL 2002	NCC 2004	MIT 2006	EPRI 2002	NCC 2004	Rubin 2004	MIT 2006	EPRI 2002	Simbeck 2003
Cost year	2005	2002	2003	2006	2000	2003	2004	2006	2000	2000
Technology	subC	subC	SubC	SC	SC	SC	SC	USC	USC	USC
Efficiency (%, HHV)	34.3%	37.4%	36.7%	38.5%	40.5%	39.3%	39.3%	43.3%	42.8%	43.1%
TPC ($/kW$_e$)	1280	1114	1230	1330	1143	1290	1076	1360	1161	1290
Annual CC (% on TPC)	15.1%	16.8%	14.3%	15.1%	15.5%	14.2%	16.6%	15.1%	15.5%	15.0%
Fuel price ($/MMBtu)	1.5	0.95	1.5	1.5	1.24	1.5	1.27	1.5	1.24	1.0
Capacity factor (%)	85%	85%	80%	85%	65%	80%	75%	85%	65%	80%
Electricity Price[3]										
Capital charge (cents/kWh)	2.60	2.52	2.51	2.70	3.10	2.62	2.71	2.76	3.15	2.77
O&M (cents/kWh)	0.75	0.8	0.75	0.75	1.00	0.75	0.79	0.75	0.95	0.74
Fuel (cents/kWh)	1.49	0.87	1.39	1.33	1.04	1.30	1.10	1.18	0.99	0.79
COE (cents/kWh)	4.84	4.19	4.65	4.78	5.15	4.67	4.61	4.69	5.09	4.30

2.2 Capture of CO_2 from a pulverized coal plant

The sequestration of CO_2 requires that the CO_2 be in a single phase flow, with minimal amounts of non-condensible gasses such as nitrogen, argon and oxygen. In addition, it also needs to be free of contaminants such as water that could corrode the pipeline. It is unclear if sulfur dioxide needs to be removed, as some studies have suggested that the presence of the contaminant could negatively affect the porosity of the sequestration injection zone, reducing the capacity of the CO_2 reservoir [MIT 2006].

[3] As reported in studies

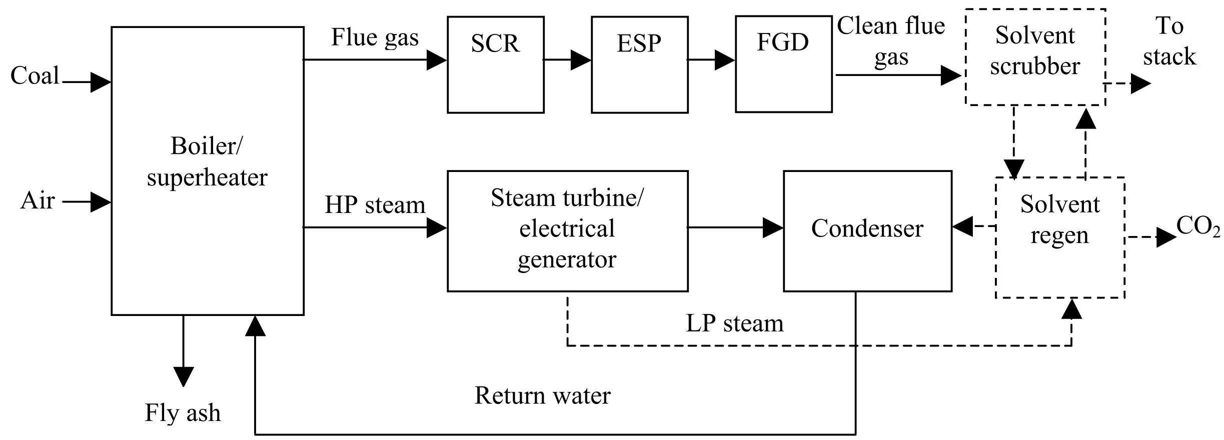
The two leading technologies that have been proposed for CO_2 separation from pulverized coal plants are solvent-based separation and oxyfiring. Solvent-based separation uses a solvent, such as an amine, to separate the CO_2 post-combustion from the flue gas. Oxyfired combustion uses relatively pure oxygen (95% or higher) for combustion in place of atmospheric air. The resulting flue gas is primarily CO_2, with trace amounts of oxygen and other gases that can be flashed off during the compression of the CO_2.

2.2.1 Solvent-based CO_2 capture

Solvent-based CO_2 capture systems remove CO_2 from the flue gas by chemically absorbing the CO_2 with a solvent, typically an amine such as monoethanolamine (MEA). After scrubbing the CO_2 from the raw flue gas, the solvent is then regenerated by heat, which releases the CO_2 from the amine solution. The steam is generally supplied by diverting some of the steam that would have otherwise driven the lowest pressure steam turbine section. The CO_2 is released at ambient pressure, and needs to be compressed and dried to be ready for pipeline transport to a suitable sequestration site

Figure 2-4 illustrates a process flow diagram for a pulverized coal power plant with a solvent CO_2 capture system.

Figure 2-4 **Process flow diagram for a pulverized coal plant with solvent CO_2 capture**



An advantage of solvent-based CO_2 capture and sequestration is that current power plant designs to be used with little modifications to the front end of the plant. The boiler design, and steam cycle remain the same. In addition, solvent capture of CO_2 from PC plants has been used on a commercial scale for many years to produce CO_2 for industrial applications, although it has generally been done on a small scale, capturing the CO_2 from a small proportion of the flue gas stream.

Some of the issues that face the use of solvents for CO_2 capture and sequestration include the costs of the scrubber and solvent, controlling solvent loss and the significant amount of steam that is used in stripping the CO_2 from the saturated solvent. The costs and performance penalties can be minimized by selecting high-efficiency ultra-supercritical boiler designs that produce less flue gas (and CO_2) per unit of electrical output than current boiler designs. These boilers have been in use in Japan and Europe, but have not yet been deployed in North America.

The use of solvents for CO_2 capture has been characterized in a number of engineering studies. Table 2-3 outlines the cost and performance characteristics from these studies.

Table 2-3 Survey of performance, costs and COE for PC with CO_2 capture

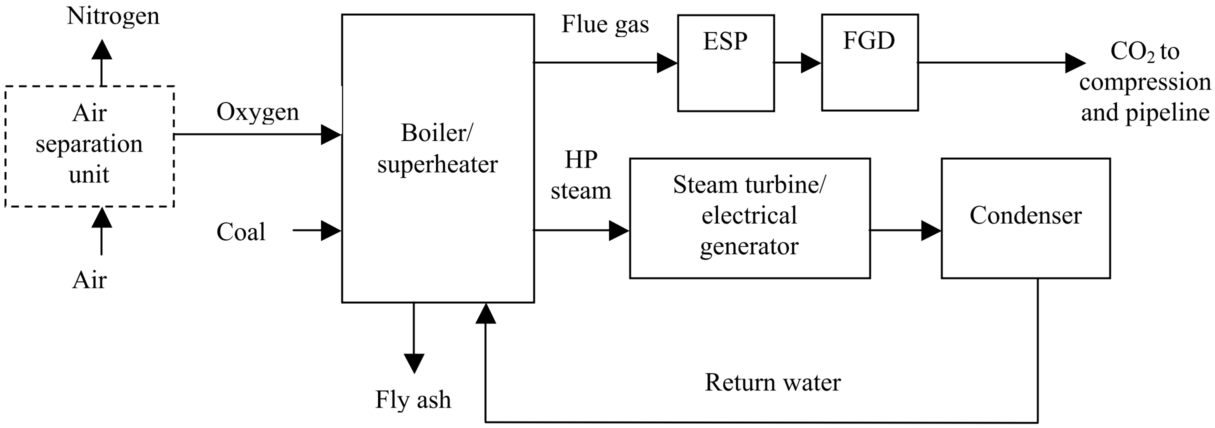
Study	MIT 2006	NETL 2002	MIT 2006	EPRI 2002	Rubin	MIT 2006	EPRI 2002	Simbeck 2002
Cost year basis	2005	2002	2005	2000	2004	2005	2000	2002
Technology	SubC	SubC	SC	SC	SC	USC	USC	USC
Plant output (MW, net)								
Efficiency (%, HHV)	25.1%	26.6%	29.3%	28.9%	29.9%	34.1%	31.0%	33.8%
TPC ($/kW)	2230	2086	2140	1981	1729	2090	1943	2244
Annual CC (% on TPC)	15.1%	16.8%	15.1%	15.5%	16.6%	15.1%	15.4%	15.0%
Fuel price ($/MMBTU)	1.5	0.95	1.5	1.24	1.27	1.5	1.24	1.0
Capacity Factor (%)	85%	85%	85%	65%	75%	85%	65%	80%
Electricity price[4]								
Capital charge (cents/kWh)	4.52	4.72	4.34	5.38	4.36	4.24	5.27	4.80
O&M (cents/kWh)	1.60	1.67	1.60	1.71	1.6	1.50	1.61	1.28
Fuel (cents/kWh)	2.04	1.22	1.75	1.46	1.45	1.60	1.36	1.01
COE (cents/kWh)	8.16	7.61	7.69	8.55	7.41	7.34	8.25	7.09

Oxyfired CO_2 capture

In an oxyfired pulverized coal plant the oxygen required for combustion is provided by an air separation unit that separates the oxygen from the other gases present in atmospheric air, which is primarily nitrogen, along with some other trace gases. After the flue gas is treated to remove particulate matter, it is dried, flashed to separate out non-condensable gasses and compressed for transport. It is uncertain whether or not the sulfur compounds would have to be removed from the flue gas; there is potential that the presence of sulfur in the CO_2 being sequestered could affect its injectivity, but this issue has not been studied definitively. There may also be permitting issues surrounding the injection of a SO_2, which is a criteria air contaminant. Figure 2-5 is a simplified process flow diagram for an oxyfired pulverized coal plant with CO_2 capture.

[4] As reported in studies

Figure 2-5 **Process flow diagram for an oxyfired pulverized coal plant with CO_2 capture**



The use of oxyfiring for CO_2 capture may have both technical and cost advantages over solvent-based post-combustion capture technologies. Cryogenic air separation is a proven technology that is used currently on a large scale for industrial purposes, and the costs and operation of these units are well understood. The boiler can also be designed to be smaller and less expensive to construct because of the higher combustion rates and temperatures that are possible with pure oxygen combustion

Some of the difficulties surrounding oxyfiring is the lack of operational experience. To date, no commercial scale oxyfired PC plant has been constructed. The higher temperatures and properties of oxyfired combustion may pose some difficulties for materials selection and design, although it is expected that through the use of exhaust gas recirculation that it should be able to properly control the combustion temperature to prevent damage to the boiler. Boiler air leakage is also a concern for oxyfired PC plants. Typically, boilers run under a slight negative pressure to prevent hot combustion gasses from escaping into the power building. The excess air that enters the boiler is not a concern for air-fired boilers, but in the case of an oxyfired boiler this air would dilute the CO_2 leaving the boiler with non-condensable gasses such as nitrogen and oxygen, which would then have to be separated during compression, adding to the capital and energy costs of the plant.

There are also large power requirements for the air separation unit. Some of these power needs can be made by integrating the air separation unit with the steam turbine, using shaft power to drive the air compressors in the air separation unit, but this integration makes the design and operation of the plant more complex. Several studies have evaluated oxyfired combustion for new build plants. A summary of these studies is presented in Table 2-4.

Table 2-4 Survey of performance and economics of PC oxyfired studies

Study	**NETL 2002**	**MIT 2006**	**Dillon 2004**	**Simbeck 2000**	**Andersson 2004**
Cost year basis	2002	2005	2004	2000	2004
Technology	SubC	SC	SC	USC	USC
Plant output (MW,net)					
Efficiency (%, HHV)	26.6%	30.6%	29.9%	28.9%	31.0%
TPC ($/kW)	2086	1900	1729	1981	1943
Annual CC (% on TPC)	16.8%	15.1%	16.6%	15.5%	15.4%
Fuel price ($/MMBtu)	0.95	1.5	1.27	1.24	1.24
Capacity factor (%)	85%	85%	75%	65%	65%
Electricity price[5]					
Capital charge (cents/kWh)	4.72	3.85	4.36	5.38	5.27
O&M (cents/kWh)	1.67	1.45	1.6	1.71	1.61
Fuel (cents/kWh)	1.22	1.67	1.45	1.46	1.36
COE (cents/kWh)	7.61	6.98	7.41	8.55	8.25

[5] As reported in studies

2.3 Retrofitting of existing PC plants, and capture-ready options

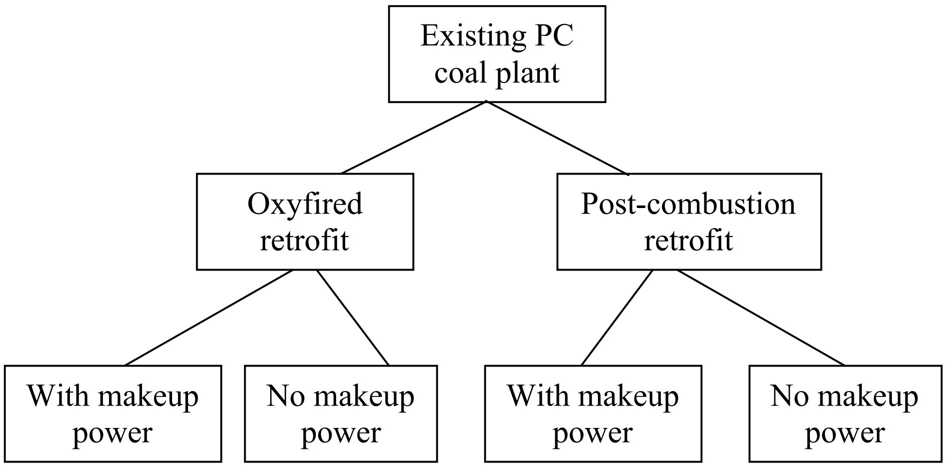
With over 300 GW of existing PC plants in the United States, the ability to economically retrofit existing plants for CO_2 capture could be an effective method by which CO_2 emissions can be curtailed, and the growth of atmospheric CO_2 concentrations constrained. Some of the issues that face owners considering retrofitting their PC plants for carbon capture and sequestration include:

- Capital costs and the associated financing of the capture equipment
- Large reduction in the net output of the plant, and the need to acquire makeup power
- Increased operation and maintenance costs
- Increased total and dispatch cost of electricity (COE)
- Location and access to a suitable sequestration site
- Timing and length of the downtime required for the retrofit
- On-site availability of space
- Design and age of existing plant

The issues surrounding the retrofitting of these plants are significant, and the suitability for retrofit for each plant would have to be evaluated independently, as some of these factors would be larger in magnitude, or have greater impacts for some plants compared to others.

The two major categories of retrofit technologies that can be used for existing PC plants are the same as the greenfield technologies that were described earlier in this report – oxyfuel combustion and solvent-based post-combustion capture. In addition to the basic capture technologies, several variations of each has been considered by several studies. These include the use of auxiliary natural gas boilers or combined cycle gas turbines (NGCC) to provide the additional steam needed for stripping the CO_2 in the regeneration cycle of the amine stripper and makeup power to offset the power losses associated with the additional equipment and CO_2 compression. Figure 2-6 illustrates the leading options that exist for retrofitting a plant for CO_2 capture.

Figure 2-6 Options for retrofitting existing power plants



The differences between a plant design optimized for no consideration of capture (a baseline plant) and a capture-ready plant are expected to be significant and these differences will have considerable impacts on the costs, operability and output of a baseline plant that has been retrofitted for COE. In addition, the optimal design of a capture-ready plant depends on the technology that is expected to selected for capture when the plant is ultimately retrofitted. The following three sections describe these differences for issues specific to post-combustion, oxyfuel combustion and issues universally applicable to both technologies. It also discusses the capture-ready options for all of the technologies.

2.3.1 Retrofit issues and capture-ready opportunities for post-combustion PC

While no major technical hurdles exist for retrofitting PC plants for capture with post-combustion amine scrubbing, the expected de-rating, capital requirements and increase in operation and maintenance costs (including fuel) are expected to pose significant challenges to owners and policymakers if and when decisions need to be made to reduce CO_2 emissions from these facilities. Some of these impacts can be minimized for plants that have not already been built by employing capture-ready designs and technologies.

Table 2-5 provides a high-level, component-by-component overview of the issues surrounding the retrofit of a PC plant with amine capture, and the capture-ready options that can be deployed to minimize the impacts of these issues.

Table 2-5 Retrofit issues and capture-ready options for PC with amine capture

Component Group	Level of change required for retrofit	Capture-ready options
Boiler	None - but output of boiler will not be sufficient to supply steam to LP section of turbine at rated capacity as LP steam required for MEA solvent regeneration	1. High efficiency boiler
Flue gas cleanup	Moderate - SCR/ESP unchanged, but FGD may require upgrade to meet stringent SO_2 limits of MEA solvent	1. Over-design FGD 2. Leave space for upgrade of FGD
Ducting and Stack	Moderate - flue gas would need to be re-routed to amine stripper	1. Leave space and tie-ins for ducting to amine stripper
Steam turbine/ generator	Major - steam turbine may need to be rebuilt for optimal performance with lower LP steam rates unless makeup steam provided from alternate source	1. Select turbine that is efficient at below rated operating conditions 2. Select turbine that is easily modified to lower LP steam rate
Auxiliary electric plant	Minor - extra power needed for pumps and fans	1. Leave space for equipment
Balance of Plant	Major - addition of pumps, fans and CO_2 compression and drying equipment	1. Leave space for equipment

A more detailed description of the issues surrounding retrofit and capture-ready opportunities for PC plants with post-combustion catpture are described below.

Boiler

The conversion efficiency of the power plant is heavily dependent on the selection of the boiler. Sub-critical boilers, which run at pressures below the supercritical point of water (22.1 MPa) dominate the current fleet of US and world coal plants, but offer significantly lower conversion efficiencies than supercritical or ultra-supercritical boilers (see Table

2-1). For a given electrical output, these lower conversion efficiencies relate directly to higher CO_2 emissions, and correspondingly larger capital and energy costs and a larger de-rating after retrofit. Table 2-6 illustrates the impact of selecting a higher efficiency boiler on the de-rating and efficiency of the plant after retrofit with post-combustion capture.

Table 2-6 Impact of steam cycle on post-combustion PC retrofit de-rating and efficiency [MIT 2006]

Technology	Sub-critical	Supercritical	Ultra-supercritical
Baseline plant			
Net output before retrofit (MW)	500	500	500
Efficiency before retrofit (%, HHV)	35.0%	39.2%	44.0%
CO_2 Emissions (t/MWh-e)	0.91	0.81	0.72
Retrofitted plant			
Retrofit de-rating (%)	41.5%	36.0%	33.0%
Net output after retrofit (MW)	293	315	335
Efficiency after retrofit (%, HHV)	20.5%	25.0%	29.5%
CO_2 Emissions (t/MWh-e)	0.06	0.05	0.04

Flue gas cleanup

The requirements for flue gas cleanup are more stringent with an amine capture system than is required by current source emission standards in the US. The primary concern is SO_2, as the amine scrubbing solvent can become loaded with SO_2, which can severely degrade the CO_2 removal performance of the capture system. Acceptable levels of SO_2 in the flue gas are 10 ppm, significantly lower than what is required by air quality regulations. In order to address this gap, the flue gas cleanup system would have to be upgraded, requiring additional investments in flue gas desulfurization equipment.

Approaches for capture-ready that can be taken for this technology would be to over-design the flue gas desulfurization unit to ensure that the required sulfur levels can me met without additional capital investments at the time of retrofit. Another option would be to leave additional space in the vicinity of the FGD unit to allow sufficient room for upgrades without major modifications to the existing layout of the plant.

Ducting and stack

The ducting and stack would have to be modified in the event of a retrofit, as the amine stripper would have to be inserted between the flue gas desulfurizer and the stack. This may pose difficulties if little room exists for the equipment; additional ducting may be required to locate the amine stripper in a location adjacent to the plant.

Steps that can be taken to make the plant more capture-ready include specifying tie-ins in the existing ductwork, and leaving additional space between the FGD and the stack to accommodate the placement of the amine scrubber during the retrofit.

Steam turbine/electrical generator

One of the major impacts of a retrofit to capture with a post-combustion capture system is the steam requirements of the CO_2 stripper. A 20-30% reduction in the electrical output of the steam turbine/electrical generator is expected due to the diversion of significant amounts of low-pressure steam to the reboilers of the MEA CO_2 recovery system [Alstom 2002]. One option that exists to address the reduction in low-pressure steam going to the turbine in the event of a retrofit is the addition of a supplementary boiler or combined cycle natural gas turbine to provide the necessary make-up steam. This may not be feasible because of the additional capital required for the extra boiler, as well as the costs of fuelling this additional unit, especially if it is fuelled by natural gas. Alternatively, the low-pressure section of the turbine may need to be rebuilt to accept the lower steam rate.

A capture-ready option would be to specify a steam turbine that is able to operate at an acceptable efficiency at lower heat rates; it is unclear at this point as to what design changes would be required to satisfy this requirement.

Auxiliary electric plant

The addition of post-combustion capture would require additional electric capacity to power the extra pumps and fans that would be necessary to run the CO_2 stripping equipment. It is not expected that these changes would be very significant, however. Cost savings could be realized in the retrofit if in the initial design phase extra space is allocated for the additional equipment.

2.3.2 Retrofit issues and capture-ready opportunities for oxyfired PC

Less operational experience exists with oxyfired PC plants as compared to post-combustion capture, but initial studies indicate that the oxyfired technology may have efficiency and cost advantages over post-combustion that may make it the preferred technology for retrofit. Table 2-7 provides a high-level, component-by-component overview of the issues surrounding the retrofit of a PC plant with oxyfiring, and the capture-ready options that can be deployed to minimize the impacts of these issues.

Table 2-7 Changes to major components in a PC boiler for oxyfired retrofit

Component Group	Level of change required for retrofit	Capture-ready options
Boiler	Major - air handling system required for CO_2 recycle, boiler may need to be improved to minimize air leaks	1. Highest efficiency boiler design 2. Low leakage boiler design 3. Leave space for equipment
Flue gas cleanup	Minor - SCR may no longer be necessary, or require changes to run with CO_2 rich gas	1. Install FGD system that can work with both flue gas compositions
Ducting and Stack	Moderate - addition of CO_2 recycle system required	1. Leave space and tie-ins for CO_2 recycle system
Steam turbine/ generator	Minor - same amount of steam would be delivered to turbine. Shaft power might be harnessed for ASU	No capture-ready options exist for steam turbine
Auxiliary electric plant	Major - changes to provide power to ASU and pumps	1. Leave space for equipment
Balance of Plant	Major - addition of pumps, fans and equipment for CO_2 compression, non-condensables separation and drying	1. Leave space for equipment

A more detailed description of the issues surrounding retrofit and capture-ready opportunities are described below.

Boiler

As is the case with a post-combustion retrofit, the conversion efficiency of the power plant is heavily dependent on the selection of the boiler. Table 2-6 illustrates the impact of selecting a higher efficiency boiler on the de-rating and efficiency of the plant after retrofit with oxyfired technology.

Table 2-8 Impact of steam cycle on an oxyfired PC retrofit performance [MIT 2006]

Technology	Sub-critical	Supercritical	Ultra-supercritical
Baseline plant			
Net output before retrofit (MW)	500	500	500
Efficiency before retrofit (%, HHV)	35.0%	39.2%	44.0%
CO_2 Emissions (t/MWh-e)	0.91	0.81	0.72
Retrofitted plant			
Retrofit de-rating (%)	36.0%	32.1%	28.6%
Net output after retrofit (MW)	321	340	357
Efficiency after retrofit (%, HHV)	22.4%	26.6%	31.4%
CO_2 Emissions (t/MWh-e)	0.09	0.07	0.06

Flue gas cleanup

An oxyfired PC plant, unlike a plant with post-combustion amine capture does not require sulfur control for the capture equipment to work properly. It is possible, however that the sulfur present in the flue gas (as SO_2) would need to be controlled as it is a criteria air pollutant, and there may be issues surrounding the permitting of an injection well that has SO_2 present in the CO_2 to be sequestered. In addition, it is uncertain whether or not the sulfur compounds would have to be removed from the flue gas; there is potential that the presence of sulfur in the CO_2 being sequestered could affect its injectivity but this issue has not been definitively studied.

If flue gas desulfurization is required, it is uncertain as to whether or not the design of currently used systems would work with the new (primarily CO_2) flue gas composition without requiring major modifications. This issue should be further studied to determine if steps can be taken to ensure that the FGD system initially specified and construction is able to operate efficiently after retrofit.

Ducting and stack

The ducting and stack would have to be modified in the event of an oxyfired retrofit, as a flue gas recycling system would have to be installed in order to control the combustion temperatures in the boiler. This may pose difficulties if no room is left for this extra piping during the initial construction of the plant. Steps that can be taken to make the plant more capture-ready include specifying tie-ins in the existing ductwork and leaving additional space to accommodate the placement of the ducting and fans required for the flue gas recycle during the retrofit.

Steam turbine/electrical generator

A major advantage of an oxyfired retrofit over a post-combustion amine retrofit is the fact that the steam heat rate to the steam turbine is unaffected, and the steam cycle should be able to operate without any modifications. There are some efficiency advantages that can be gained by integrating the air separation unit by using shaft power from the steam turbine for air compression. Providing allowances for this integration is a capture-ready option that should be considered.

Auxiliary electric plant

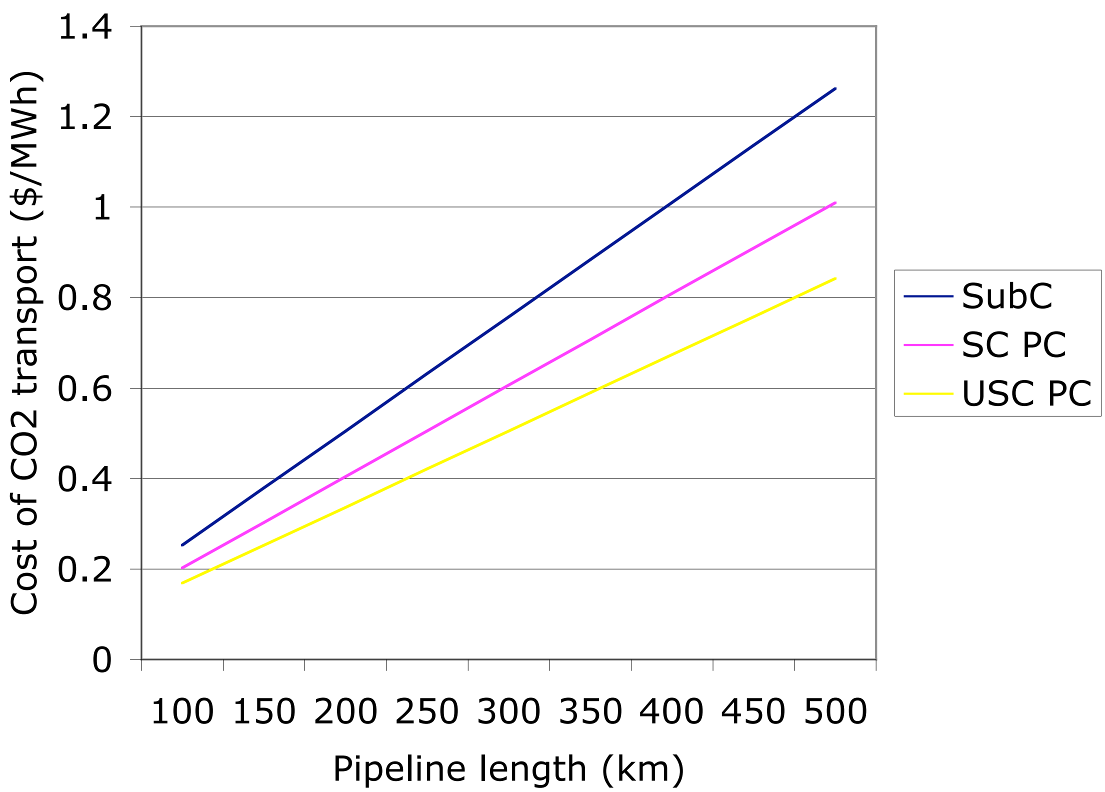
The addition of oxyfired capture would require additional electric capacity to power the additional pumps and fans that would be necessary to run the air separation unit, flue gas recycle fans and the CO_2 compressors. These power draws are expected to be quite significant, and major changes are expected to be required to the auxiliary electric plant to supply the required power. A capture-ready option for this component includes leaving extra space for the additional electrical equipment.

2.3.3 Retrofit issues and capture-ready opportunities for all PC plants

Proximity to suitable sequestration site

The costs of transporting and sequestering CO_2 can vary significantly, depending on how far and how technically difficult it is to dispose of the CO_2 produced in the power plant. Typical costs for a pipeline capable of handling the emissions from a 500 MW_e power plant are expected to run in the 33 M$ per 100 km and can add a significant amount to the total COE [Heddle 2003]. Figure 2-7 illustrates the impact of pipeline transport distance on the levelized cost of electricity of a retrofitted sub-critical, supercritical and ultra-superctritical PC plant.

Figure 2-7 Impact of distance of CO_2 Sequestration on COE



Downtime required for retrofit

The amount of time that a plant is required to be offline for a retrofit may cause significant operational difficulties for the plant owner. If the required downtime is short enough (under 2 or 3 months) to fit within one of the shoulder seasons where electricity demand is lower, the impact on the owner may be significantly less, as the owner's remaining capacity is more likely to be sufficient to make up for the shortfall. Alternatively, power could be purchased from another producer, generally at lower rates than during peak months. It is expected that a post-combustion retrofit would take less time than an oxyfired retrofit, because much of the equipment required for a post-combustion retrofit could be installed on-site without requiring the plant to go offline. In addition, no major changes are required to the boiler. An oxyfired retrofit is expected to take significantly more time as major changes are required to the boiler and the air handling system.

The allocation of space on the plant site as a capture-ready step is expected to reduce the time required for retrofit, as the additional space could allow for the placement of equipment before tying into the original plant, and reduce the number and complexity of major equipment replacements and re-routing.

Plant layout and available space

As outlined in Section 2.3.2, many existing plants have been built on space-constrained sites. These plants may not have the additional space available to optimally locate post-combustion capture equipment, which can add 25-40% to the footprint of a plant. In addition, many of these plants have been retrofitted previously for pollution control, namely flue gas desulfurization but some have also had selective catalytic reduction (SCR) units added to control NO_X emissions. These additions may have further reduced the amount of available space for the addition of a post-combustion capture unit.

These space constraints, as a worst-case scenario, may prevent the retrofitting of a particular plant. In other cases it may be required to move, modify or replace major components of the plant, which would add significantly to the costs of the retrofit. It may also increase the amount of downtime required for the retrofit, further impacting the economics of this option.

The capture-ready option is to leave additional space for the equipment and for the construction equipment that would be used during the retrofitting process. Land costs generally make up a very small portion of the total investment cost for a power plant. NETL estimated land costs for a new coal-fired plant to be $1.3 million, providing 200 acres for the plant, which accounted for 0.2% of the total cost of a PC plant [Parsons 2002]. Providing an additional 50 acres of land for capture equipment is a conservative (high) estimate of the amount of land required, and would add no more than 0.05% to the total cost of the plant, or $0.4 million. The changes to the plant layout may involve a larger level of investment, primarily to the piping and ducting. As a first-order estimate this study assumes that this would add 10% to the cost of the piping and ducting to a plant. NETL estimates that the costs of the ducting, stack and piping for a PC plant would be $34.6 million. This would translate into an additional $3.5 million investment to build a plant with a capture-ready layout. The total capture-ready investment for both the additional land and changes to the piping and ducting layout would be approximately $3.6 million.

2.4 *Economics and performance of retrofitted and capture-ready PC plants*

Two recent studies [Simbeck 2001 and Alstom 2002] evaluated the technical and economic aspects of retrofitting existing pulverized coal power plants. The studies focused on sub-critical PC plants, as these units comprise over 95% of the existing US stock of PC plants. Both post-combustion MEA capture and oxyfired combustion retrofits were considered. The studies were quite different in their approach for post-combustion capture; Simbeck specified the use of a natural gas boiler to provide the steam required by the MEA stripper, whereas the Alstom study assumed that the steam would be provided from the original boiler, with the steam turbine being derated to accommodate the reduction in steam available for power production. Table 2-9 summarizes the technical and economic parameters of the plants evaluated in the report.

Table 2-9 Summary of retrofit studies for PC plants

Study	**Alstom & ABB (2001)**		**Simbeck (2001)**	
Baseline plant				
Cost year basis	2000		2000	
Net output (MW_e)	434		291.5	
Initial efficiency (%, HHV)	35.0%		35.0%	
Coal input rate (MMBtu/h, HHV)	4229		2839	
NG input rate (MMBtu/h, HHV)	-		0	
CO_2 Emissions (t/MWh)	0.91		0.97	
Retrofit plant				
Capture Technology	MEA	Oxyfired	MEA with NG Boiler	Oxyfired
Cost of retrofit (M$)	409	285	234	210
Cost of retrofit ($/kW-e, after retrofit)	1604	1044	803	1060
Efficency after retrofit (%,HHV)	20.5%	22.5%	24.1%	23.3%
Net output after retrofit (MW_e)	255	255	291.5	198.5
Fuel input rate –Coal (MMBtu/hr, HHV)	4228.7	4140	2840	2892
Fuel input rate –NG (MMBtu/hr, HHV)	-	-	1289	0
Capture efficiency (%)	96.2%	93.8%	90.8%	91.5%
CO_2 Emissions (t/MWh)	0.06	0.09	0.12	0.12

It is important to note that the expected efficiency penalty of a retrofit is much higher than a greenfield plant. This is true for both post-combustion and oxyfired retrofits.

In the case where the existing plant proves to be unsuitable for retrofit, more aggressive approaches exist. These include rebuilding the existing unit to include CO_2 capture and improve the overall technology on the site, resulting in an optimally sized and balanced unit. This could be done by upgrading to a supercritical PC or an ultra-supercritical PC with post-combustion CO_2 capture, by upgrading to oxy-fired supercritical technology, or by installing IGCC with CO_2 capture. In this case, very little of the original plant is retained, and most of the major components such as the boiler, steam turbine, air handling equipment and much of the accessories would need to be replaced. Components that could be re-used include the on-site support facilities, coal handling equipment and stack, but these generally respresent a small fraction of the total plant cost – 10% or less [Simbeck 2005]. The performance of these rebuilt units would be the same as greenfield plants, and have not been summarized for this study.

2.5 Current investments and actions in capture-ready PC plants

Although there is considerable interest in capture-ready plants in both North America and in Europe, there are not as of yet any firm plans for the construction of this type of plant. Saskpower, the publicly owned utility in the Canadian province of Saskatchewan had announced the construction of a capture-ready plant, to be online by 2013 [Clayton 2005]. Because of newer federal government directives on CO_2 emissions in order to meet Canada's Kyoto Protocol requirements Saskpower has moved instead to perform an engineering design study for a coal plant with CO_2 capture, and forgo the capture-ready concept [Stobbs 2006]. Before forgoing the capture-ready options, the steps that Saskpower had outlined to make the plant capture-ready included:

- Allocation of space for capture equipment
- Addition of connection points for steam, flue gas extraction to capture equipment

- Selection of steam turbine that could be readily retrofitted for optimized performance under reduced steam loads, which would occur after a retrofit

The project was being built to accommodate whatever technology would be most appropriate for capture when the plant was retrofitted, be it an amine-based post-combustion capture, oxyfired combustion with flue gas capture, or another technology that is currently not technically or economically feasible. No cost estimates had been developed for the capture-ready investments before the decision to change the design of the plant had been made.

3 INTEGRATED GASIFICATION/COMBINED CYCLE PLANTS

Integrated gasification and combined cycle (IGCC) technology for electrical power production is an advanced design that uses coal gasifiers, fuel gas processing subsystems, a combustion turbine, heat recovery steam generator and a steam turbine. Both the combustion turbine and the steam turbine drive electrical generators, much the same way a natural gas combined cycle power plant operates.

IGCC technology offers advantages over PC plants for CO_2 capture as the CO_2 can be separated at higher partial pressures, reducing the amount of capital required and the energy penalty for capture. Less operational experience exists with IGCC plants, however and they are more complicated to operate and construct than a traditional PC plant. Some of the issues that are specific to retrofitting IGCC plants for CO_2 capture include:

- The water-gas shift reaction of the syngas and CO_2 removal reduces the heating value of the syngas by approximately 15%, which would cause a de-rating of the combustion turbine [EPRI 2003].
- The convective and radiative gas coolers, if present, may no longer be required, as the addition of water into the syngas to produce steam for the water-gas shift reaction may sufficiently reduce the temperature of the syngas.
- The acid gas removal system would require the addition one more stage to remove CO_2 in addition to H_2S. An MDEA system (if present) may need to be removed and replaced with 2-stage Selexol-type acid gas removal system.
- The combustion turbine combustors may need to be changed and a blade retrofit may be needed in order to operate on diluted hydrogen gas.
- Compressed air for the air separation unit may no longer be available from the turbine, necessitating the addition of a parallel air compressor.
- Re-arrangement of existing equipment may be required to accommodate the addition of the water-gas shift reactors, second acid gas removal stage and CO_2 compression and drying equipment.

The capture-ready options for IGCC plants have been more widely explored, and several opportunities exist to reduce the de-rating and capital costs of a retrofit. These options include:

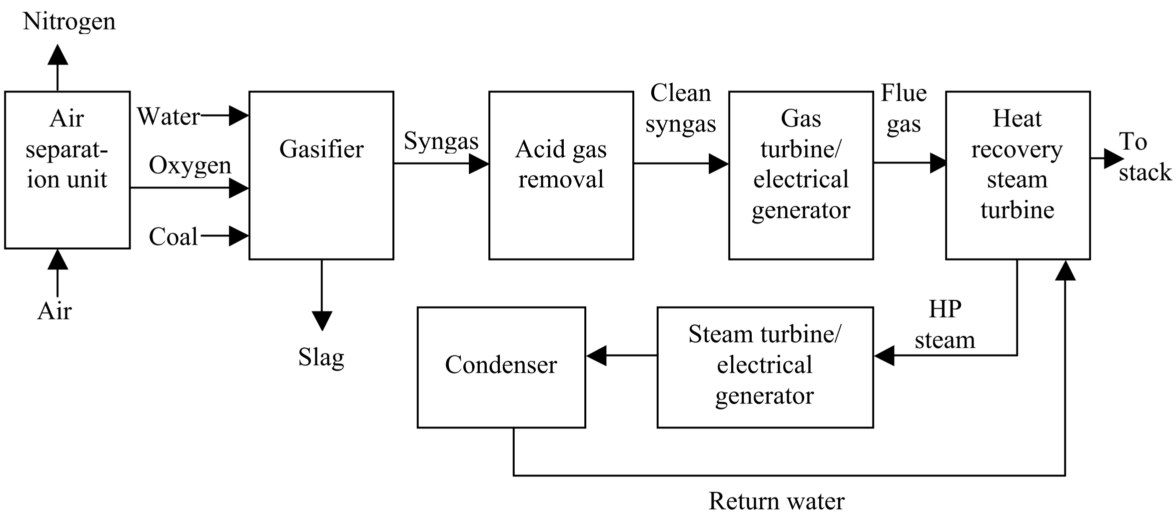
- The pre-investment in over-sizing the gasifier and air separation unit, to ensure that sufficient hydrogen can be produced to maintain full loading of the turbine, reducing the de-rating of the plant.
- The selection of a high-pressure gasifier design, which would reduce the energy requirements of the CO_2 compression equipment.
- The selection of a water quench gas cooler, which eliminates the capital in gas coolers that may be stranded after a retrofit.
- Leaving extra space for the addition of the water-gas shift reactors, second acid gas removal stage and CO_2 compression and drying equipment
- Ensuring that the plant site is located close to an appropriate sequestration site, and the required easements for a CO_2 pipeline system is available.

3.1 IGCC technology

In an IGCC plant without CO_2 capture, coal is fed into a high temperature and pressure gasifier and combined with an oxidant (typically 95% pure oxygen from an air separation unit). This gasification process produces a syngas primarily composed of hydrogen and CO, along with trace amounts of other gases and contaminants, primarily SO_2, H_2S and CO_2. This syngas is then treated to remove contaminants, and fed to a combustion turbine that drives an electrical turbine. Some of the thermal energy in the combustion turbine exhaust is recovered through the use of a heat recovery steam generator (HSRG), which produces steam to run a Rankine cycle steam turbine. The overall conversion efficiency for current IGCC designs range from 38 – 44%, depending on the type of gasification and heat recovery specified.

Figure 3-1 illustrates a simplified process flow diagram of this process.

Figure 3-1 **Process flow diagram for IGCC plant**



There are three basic gasifier designs used for coal gasification that can be used in an IGCC plants – entrained flow, fluidized bed and fixed bed designs. The entrained flow gasifier is the design that has been used in the four coal-fired IGCC plants currently in use in the world, and is the leading design that is currently being discussed for new IGCC plants.

Gasifier type and operating pressure

The major commercial providers of entrained-flow gasifiers for IGCC applications are ConocoPhillips, GE/Texaco and Shell. While the conceptual design of the gasifier is similar between the various providers, significant differences exist between them, and these design features affect their performance, cost and suitability for CO_2 capture. Table 3-1 outlines the major technical differences between the leading gasifier options.

Table 3-1 Design criteria of leading gasifier types [Maurstad 2005]

Gasifier Type	Shell	GE/Texaco	ConocoPhillips
Vessel type	Membrane/water wall	Refractory	Refractory
Burners	Multiple stage	Single single stage	Two-stage
Feed type	Dry coal – lock hopper & pneumatic conveying	Wet slurry, single stage coal feed	Wet slurry, two-stage coal feed
Approximate operating pressure (MPa)	Up to 4.1	3.4 – 6.2	Up to 4.1 (currently working on higher pressure designs)
Gas cooling	Gas quench & convective cooling	Water quench & convective cooling (radiant cooling option)	Chemical quench & convective cooling

Some of the disadvantages of these designs include short lifespan of the refractory (except Shell) because of the high temperatures present in the gasifier (over 1400 °C), the cost of the air separation unit (ASU) that is required in order to supply the oxygen required for the gasifier operation, and the difficulties of capturing and using the excess heat produced by the exothermic partial combustion of the coal that occurs in the gasifier. Despite these disadvantages, the leading gasifiers for deployment in the near term in IGCC are all of the entrained-flow design.

Within the different suppliers of entrained gasifiers, the optimal selection for an IGCC plant depends on a number of factors. The Shell gasifier uses dry feed, whereas the GE and ConocoPhillips designs use wet-slurry feed, which increases the moisture content of the infeed to up to 35% by weight. Wet slurry feed systems are inherently simpler and less expensive than the dry feed systems that require lock hoppers to introduce the coal into the gasifier, and the additional water that is added when the coal is fed into the gasifier is needed for the gasification process anyways for high-rank drier coals, such as eastern bituminous and sub-bituminous coals. Wet slurry feed systems become less attractive when used with high moisture coals such as lignites, as excess water is introduced into the gasifier, and non-recoverable energy is wasted in the latent heat of the excess water vaporized in the gasifier.

Pressure is also a design criterion that has a significant effect on the performance of the system. Wet-slurry feed gasifiers are also capable of operating at higher pressures, which increases the partial pressure of the CO_2 in the syngas after the water-gas shift process, reducing the energy requirements to compress the CO_2 for transportation by pipeline to the sequestration site. While the basic design of a gasifier (as outlined in Figure 3-1) is the same for each of the gasification unit providers, the design specifications of the major components differ significantly. Low pressure gasifiers (Shell, ConocoPhilips and the GE standard design offering) do not require as much material in their construction and reduce the construction and materials costs of the gasifier, but would be less optimal for use with new, higher efficiency turbines when they are ready for use with H_2-rich gasses (such as the GE H-class, and Siemens/Westinghouse G&H classes) [Bechtel 2006].

For capture, high-pressure gasifiers reduce the energy required for compressing the CO_2 to the pressures necessary for transporting in a pipeline for sequestration. It would also reduce the energy requirements of the acid gas removal system.

Acid gas removal

The removal of contaminants in the syngas is important to ensure that the combustion turbine is not damaged and can run for long periods of time between servicing, and that the exhaust does not contain levels of SO_2 that exceed permissible air pollutant levels. Sulfur is the primary contaminant of concern, but others, such as heavy metals must be removed as well. The removal of sulfur is known as acid gas removal (AGR) and is performed after the syngas is cooled. Two main technologies are available for AGR – chemical solvents based on aqueous methyldiethanolamine (MDEA) or a Selexol process based on a physical solvent. The because of its thermo-chemical properties, MDEA process is more suited for low-pressure applications (ie Shell, ConocoPhillips and low-pressure GE), and the Selexol process is more suited to high pressure applications (such as a high-pressure GE gasifier).

The Selexol process has an advantage for capture as it is also able to remove CO_2 with lower energy requirements than an MDEA-based process. This would minimize the level of modifications that would be required if the plant was retrofitted for CO_2 capture, and reduce the de-rating of a plant after retrofit.

Combustion turbine

The designs of combustion turbines for IGCC plants are based on current designs being offered for natural gas combined cycle (NGCC) power plants. For use in an IGCC plant, the designs of these combustion turbines are modified for use with syngas, which has different combustion properties, heat content and thermal characteristics than natual gas. The changes required are relatively minor, however, and generally involve changes to the combustors, blade design and cooling. It is expected that the major providers of turbines (GE and Siemens) will be able to adapt their current combustion turbine offerings for syngas combustion, although it is unclear as to whether or not these turbines will be able to use hydrogen gas if these plants are converted to CO_2 capture at some point in the future without requiring major modifications.

3.2 Economics of IGCC plants

To date, IGCC plants have not been widely deployed, primarily due to the cost and complexity of the units. The few commercially deployed units are discussed in Section 4.2. Much activity has occurred in the research and academic communities in evaluating IGCC technologies, and IGCC has been the subject of several recent major studies that have summarized the technical and economic performance of a number of different IGCC designs. Table 3-2 summarizes the results of these studies.

Table 3-2 Summary of studies for IGCC plants without CO_2 capture

Study	MIT 2006	EPRI 2002	Rubin 2004	Simbeck 2000	NCC 2003	NETL 2002
Gasifier type	Texaco	E-Gas	Texaco	Texaco	E-Gas	E-Gas
Efficiency (%, HHV)	38.4%	43.1%	37.5%	43.1%	39.6%	44.9%
TPC ($/kW$_e$)	1430	1111	1171	1293	1350	1167
Annual CC (% on TPC)	15.1%	15.5%	16.6%	15.0%	14.5%	17.4%
Fuel price ($/MMBtu)	1.5	1.24	1.27	1	1.5	0.95
Capacity factor (%)	85%	65%	75%	80%	80%	85%
Electricity price						
Capital charge (cents/kWh)	2.90	3.03	2.95	2.77	2.80	2.73
O&M (cents/kWh)	0.99	0.76	0.72	0.74	0.89	0.61
Fuel (cents/kWh)	1.33	0.98	1.16	0.79	1.29	0.72
COE (cents/kWh)	5.13	4.77	4.83	4.30	4.99	4.06

3.3 Existing IGCC plants

Although coal gasification has been in use since the 1920s, the application of the technology for power generation has been very limited, and large scale units have only been built with significant government subsidies. Currently, there are only 4 commercially operating IGCC plants that use coal for electricity production in the world – two in the United States and two in Europe. All four of these units have been commercial demonstration plants with some level of government subsidies to offset their construction and/or operating costs. None of these plants are currently capable of capturing and sequestering CO_2. Table 3-3 summarizes the technical and performance details of these plants.

Table 3-3 Technical and cost details of operating IGCC plants

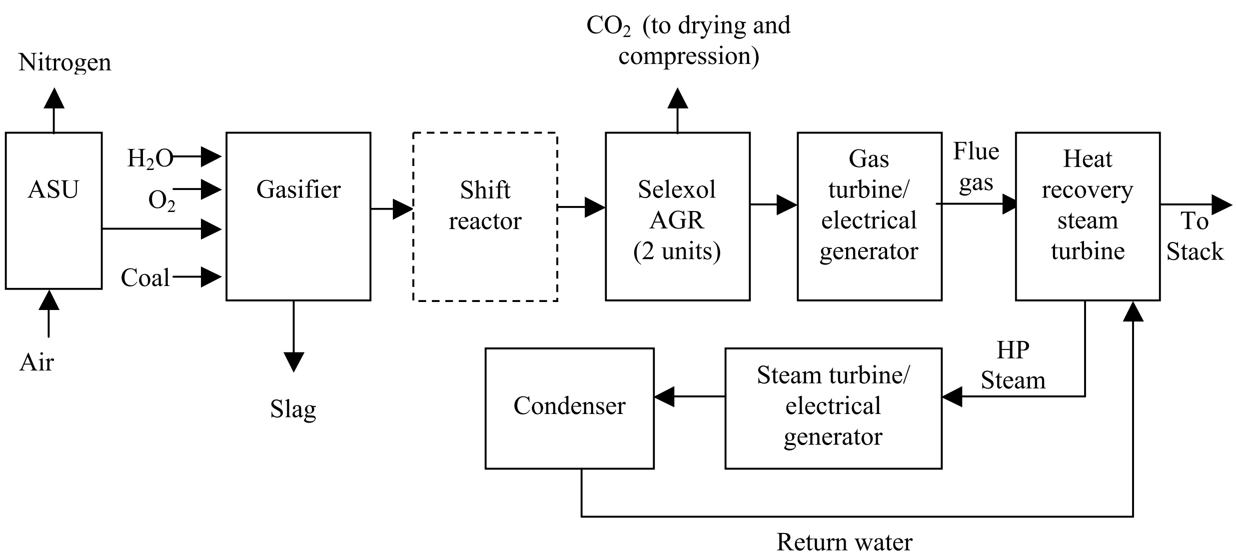
Plant	Wabash River Generating Station (USA) [Keeler 2002]	Polk River Generating Station (USA)	Buggenum (NED) [Moorehead 2003]	Elcogas (SPA) [Coca 1998]
Startup year	1995	1996	1994	1997
Gasifier type	E-Gas two-stage entrained-bed slurry feed	Texaco single-stage entrained- bed slurry feed	PRENFLO single-stage entrained-flow with dry feed	Shell single-stage dry-feed
Turbine type	GE F Class	GE F Class	Siemens V94.2	Siemens V94.3
Total plant cost ($,kW$_e$)	$1,600	$2420		$2,300
Net output (MW$_e$)	262	250	250	335
Fuel type	Low sulfur sub-bituminous and petcoke	High sulfur bituminous	Coal-biomass blend	50% petroleum coke, 50% high ash lignite
Efficiency (%,HHV)	38.3%	39.7%	39.6%	40.5%

While these plants required significant subsidies to be constructed, they have nevertheless been successful in producing low-cost power at high levels of environmental performance. The availability of the plants has also steadily improved; after experiencing numerous problems in their initial operation, both the Wabash and Polk plants have achieved acceptable availability values. In addition, both plants are high on their system dispatch list, making their capital cost recovery records excellent [Bechtel 2006].

3.4 Capture from IGCC Plants

Capturing CO_2 from an IGCC plant is an inherently less energy-intensive than either the post-combustion solvent capture or oxyfiring technologies for PC plants that were described in Chapter 2. The additional capital investment is also much less than for a PC plant. These features make the addition of CO_2 capture more promising for IGCC. Figure 3-2 illustrates the process flow diagram for an IGCC plant with CO_2 capture.

Figure 3-2 Process flow diagram for IGCC plant (raw gas CO-Shift)



The process of removing CO2 from an IGCC plant occurs before the combustion of the syngas, after leaving the gasifier and before entering the combustion turbine. The syngas (which is primarily CO and H2 with some contaminant gasses such as H2S) is reacted with water in a shift gas reactor. The shift process is exothermic and occurs at high temperatures (180 °C to 530 °C, depending on the design and type of shift reactor) and requires a metal oxide catalyst to complete. The reaction is outlined below:

CO + H2O(g) → H2 + CO2

The shift can take place before acid gas removal (known as sour gas CO-shift) or after (known as clean gas CO-Shift). Sour gas shift has the advantages of higher efficiencies from better use of enthalpy, and lower equipment costs, but offers lower maximum CO conversion (95%). It also allows for the separation of acid gasses (H_2S and CO_2) in one two-step process, reducing capital requirements. Clean gas shift gives higher CO conversion (99%), but requires more steam for the reaction and requires higher investments in equipment and catalyst to complete [Gottlicher 2004]. It is generally accepted that sour gas shift is the preferable approach for acid gas removal from a capture plant [Maurstad 2005].

The separation of the CO_2 after the shift is completed with a solvent absorber, such as a Selexol process [UOP 2005]. This process uses a solvent to remove both CO_2 and H_2S (together known as acid gas in the petroleum industry). The solvent used is made of a dimethyl ether of polyethylene glycol, is chemically inert and does not degrade with use. In a two-step process, the Selexol units first remove H_2S from the exhaust stream with a CO_2-laden solvent, as the solvent is preferentially selective to H_2S over CO_2. The solvent is then regenerated in a separate reactor through the application of heat from low-pressure steam, releasing both the CO_2 and H_2S from the solvent. The solvent is sent to the second Selexol separation unit, absorbing the CO_2 that remains in the exhaust stream. The CO_2 is dried and compressed, and is ready for transport by pipeline to the sequestration site, and the H_2 gas is sent to the combustion turbine. Finally, the solvent is sent to the first Selexol separation unit, completing the cycle.

In the case of a sour gas shift, the two Selexol separation units are in-line, treating the gas after exit from the water-shift reactor. In the case of clean gas shift, the first Selexol unit is before the water-shift reactor, and the second Selexol unit is directly after the water-shift reactor.

The water-shift process with the separation of H_2S and CO_2 in a Selexol separator has been used in the commercial sector for hydrogen and ammonia production for over 30 years, and is a mature, widely used technology.

3.5 Retrofitting of IGCC plants and capture-ready options

With only 4 coal-fired IGCC plants in commercial operation worldwide, the ability to retrofit existing plants for CO_2 capture is less important than the ability to retrofit the thousands of PC plants that are in operation, and has not been as widely studied. The issue of capture-ready for IGCC is of more interest and has been more thoroughly studied because it is probable, given current available technologies that IGCC plants that have not yet been built will be the plants that are first retrofitted for CO_2 capture. The reason for this interest is two-fold. First, these plants are expected to be among the most efficient plants, reducing the amount of CO_2 that will need to be captured per unit of electrical output. Second, the plants will be the youngest in the fleet and have the longest expected lifespan, which extends the number of years that the investment in capture equipment can be capitalized, reducing the impact of the capital investment on the levelized COE.

Some of the issues that face owners considering retrofitting an IGCC plant for carbon capture and sequestration include:

- Capital costs and the associated financing of the capture equipment
- Large reduction in the net output of the plant
- Increased operation and maintenance costs
- Increased total and dispatch cost of electricity (COE)
- Location and access to a suitable sequestration site
- Timing and length of the downtime required for the retrofit
- Physical space required for capture and construction equipment

The issues surrounding the retrofitting of these plants are significant, and the suitability for retrofit for each plant would have to be evaluated independently, as some of these factors would be larger in magnitude, or have greater impacts for some plants compared to others.

The approach that primarily has been considered for the retrofit of CO_2 capture from IGCC is pre-combustion capture, although some research has explored the option of using post-combustion capture, much like the technology that has been outlined in Section 3 for PC plants. Without major advances in capture technology, such as the commercial application of aqueous ammonia scrubbing, it is not expected that post-combustion capture will become a preferred technology option for the retrofit of IGCC plants.

Table 3-4 provides a high-level, component-by-component overview of the issues surrounding the retrofit of an IGCC plant, and the capture-ready options that can be deployed to minimize the impacts of these issues.

Table 3-4 Changes to major components in an IGCC retrofit and capture-ready options

Component Group	Level of change required for retrofit	Capture-ready options
Gasifier	Major - gasifier would have to be uprated, or combustion turbine derated. Gas cooling equipment would no longer be needed.	1. Oversized gasifier 2. Water quench cooling 3. High pressure gasifier
Air separation unit (ASU)	Major - additional oxygen needed to supply uprated gasifier. Combustion turbine may no longer be able to provide excess air for integration with ASU	1. Oversize ASU
Water-gas shift reactor	Major - water-gas shift reactors would need to be added before AGR	1. Leave space for equipment
Acid gas removal system	Major - one more stage required to remove CO_2 in addition to H_2S. MDEA system (if present) may need to be removed and replaced with 2-stage Selexol	1. Select Selexol technology for AGR system 2. Leave space for second stage of AGR
Combustion turbine	Moderate - combustors may need to be changed and blade retrofit may be needed to handle hydrogen fuel source	1. Ensure space for necessary changes to turbine
Steam turbine	None - small reduction of steam to turbine expected, should not significantly impact performance of turbine	No capture-ready options exist
Auxillary electric plant	Minor - additional power required to run second AGR, water-gas shift reactors	1. Leave space for equipment in appropriate places
Balance of Plant	Moderate level of changes - addition of CO_2 compression and drying equipment	1. Leave space for equipment in appropriate places

A more detailed description of the issues surrounding retrofit and capture-ready opportunities are described below.

Gasifier

The water-shift reaction is exothermic, and reduces the heating value of the syngas by approximately 14%, depending on the ratio of CO to H_2 in the syngas [Gottlicher 2004]. In order to maintain the same load on the combustion turbine, the output of the gasifier would need to be increased by an equivalent amount. Some gasifiers in use may have some ability to make up part of the shortfall, as they are generally designed to accommodate changes in fuel input quality and performance degradation in the equipment with time. This is not expected to make for up all of the shortfall, and a significant heat rate gap is still expected to exist after retroft. Because of this shortfall, the turbine would either need to be de-rated, or upgrades to the gasifier would be required. Another option is the introduction of a second fuel source such as natural gas to make up the lost fuel feed to the combustion turbine. This would increase the CO_2 emissions from the process that would not be captured by the CO_2 removal system, however, and potentially increase the COE of the process, depending on the cost and availability of the fuel source used. Oversizing the gasifier during the initial design and construction phase would provide the additional capacity that would be required to maintain the same heat rate to the turbine after the retrofit is complete, and represents a clear capture-ready option for IGCC.

The operating pressure of the gasifier also has a significant impact on the economics of retrofitting an IGCC plant, primarily on the economics of capturing the CO_2 from the flue gas. Lower pressure gasifier designs (such as Shell and current ConocoPhillips E-Gas designs, and the GE standard design gasifier) reduce the partial pressure of the CO_2, which increases the amount of energy required to compress the CO_2 to be piped to the sequestration site. The operating pressure also has an impact on the size and capital requirements of the acid gas removal system. Higher pressure gasifiers increase the partial pressure of the CO_2 in the syngas steam leaving the gasifier, reducing the size and cost of the CO_2 separation device. The selection of a high-pressure gasifier design, which reduces the energy requirements of the CO_2 compression equipment is a capture-ready option.

A final consideration is the type of gas cooling used in the gasifier. The optimal gas cooling process for IGCC without capture may involve radiant and convective heat transfer units. These units remove the excess heat in the syngas that is present because of the exothermic nature of the gasification process and convert it into steam that can be used in the steam turbine for electricity production.   The optimal process for IGCC with capture is water quench, because the water is already required for use in the water-shift reactor, and this additional water is expected to provide the necessary cooling. In the event of a retrofit, it is possible that the radiant and convective heat transfer equipment would no longer be necessary, and essentially would be bypassed. This would result in significant amounts of capital being wasted on these heat transfer units during the initial construction phase, would cost between 120 and 180 \$/ kW_e. The preferred capture-ready option for the type of gas cooling is to select only water quench, which would minimize the amount of capital that would be underutilized in the event of a retrofit early in the life of the plant.

Air separation unit

If, during the retrofit, the gasifier output is upgraded, the air separation unit would also need to be upgraded to supply the additional oxygen required for the gasification process. It is less likely that the air separation unit would have the same operating reserve as the gasifier, as there are fewer variables in the operation of this unit compared to the gasifier. It may be possible to upgrade the existing air separation unit to produce the required additional oxygen. Alternatively, a second air separation unit could be added to provide the additional required oxygen. The most promising capture-ready option would be to oversize the air separation unit in order to avoid the costs involved with upgrading the unit.

Acid gas removal

In order to remove both H_2S and CO_2, the acid gas removal system would need to be upgraded to include a second separation unit. If the existing acid gas removal unit is a Selexol design, it is likely a second unit could be added with minimal changes to the existing unit. If, on the other hand the unit is an MDEA-based unit, the system may have to be changed out to two Selexol units, potentially adding to the costs of the retrofit.

As a capture-ready option, the selection of a Selexol system would only require the addition of a second separation unit, along with some minor modifications to the original unit, whereas if an MDEA unit is selected, the original unit may have to be replaced by two Selexol units.

Water-gas shift reactor

Two water-gas shift reactors would have to be added to convert the CO present in the syngas to H_2 and CO_2. The major impediment to the installation of these units will be space; the plant may require significant modifications and moving of equipment if sufficient space is not available for the installation of the water-gas shift reactor.

The obvious capture-ready option is to allocate the space necessary for the water-gas shift reactors. By allotting extra space for the addition of the water-gas shift reactor, significant cost savings may be realized during the retrofit. This step would eliminate the need to move equipment, or use longer lengths of piping to accommodate equipment that could be both costly and adversely impact the performance of the plant.

Gas turbine design

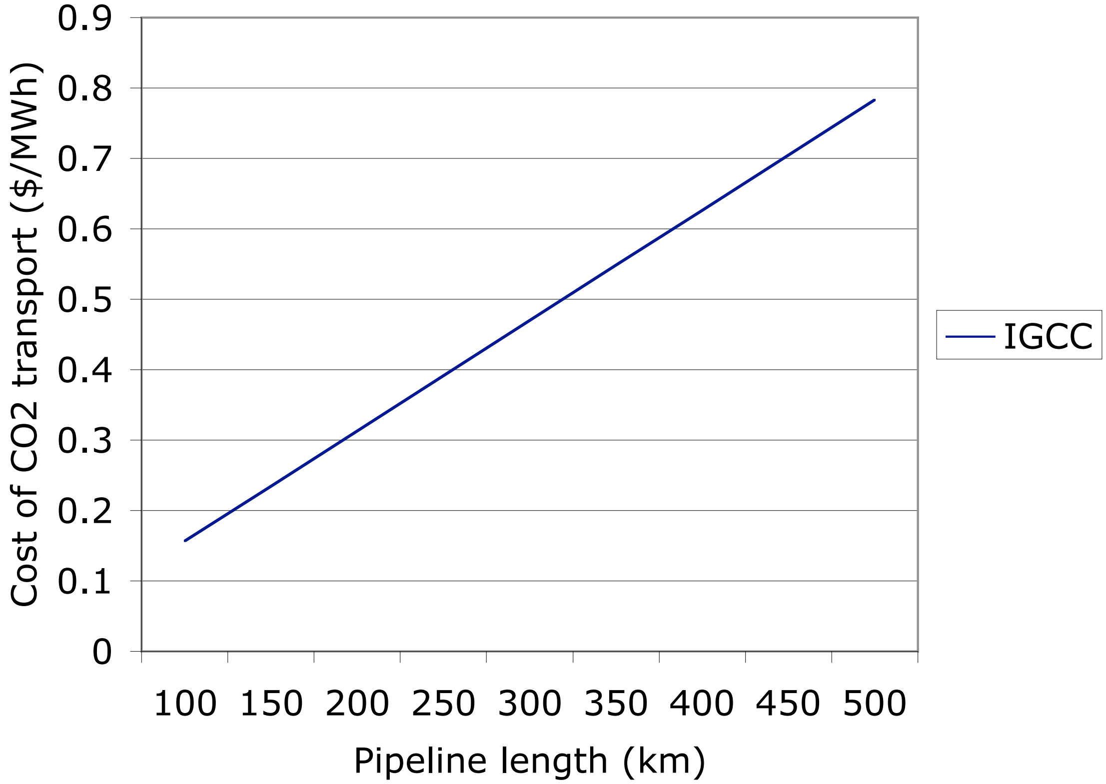
The suitability of the turbine to burn hydrogen gas depends on the design of the blades and the combustors. The combustion of hydrogen produces more moisture than syngas, and this increases the transfer of heat to the turbine blades, potentially decreasing their service life [Holt 2005a]. Steps can be taken, however, through the use of nitrogen dilution that should negate this effect. In order to address these operating changes, the inlet gas can be diluted to reduce the combustion temperature, thereby reducing the blade temperature. This would de-rate the output of the turbine and reduce the net electrical output of the plant. The other option would be to retrofit the blades of the turbine with blades that are better able to withstand the higher temperatures. It may be possible to time the replacement of these blades with a required major inspection of the turbine, which generally occurs every 48,000 hours of operating time [Kiameh 2003]. Often the turbine blades and combustor require replacement or major refurbishment at this point, and performing the upgrade of the turbine during a major overhaul would reduce the costs of the retrofit.

Another component that may need to be replaced is the combustors. Most of the turbines use a can-annular design of multiple combustors as opposed to a single combustor, which may be better suited for use with hydrogen gas. In fact a nitrogen diluted fuel can be burned successfully in a simpler combustor than what is required for natural gas, but because these IGCC units may need to start on natural gas they may require the current design with modified flow controls for the diluted oxygen [Bechtel 2006]. As a capture-ready option the selection of a single can-annular combustor during the initial construction phase would reduce the complexity and costs of retrofitting the turbine for hydrogen combustion. If the use of a single combustor is not feasible before the retrofit, another capture-ready option would be to build some flexibility into the turbine, ensuring that the space and connection points are available in order to allow for the modification of the combustors.

Proximity to suitable sequestration site

As described in Section 3.5, the costs of transporting and sequestering CO_2 can vary significantly, depending on how far and how technically difficult it is to dispose of the CO_2 produced in the power plant. Typical pipeline costs are expected to run in the 33 M$ per 100 km and can add a significant amount to the total COE [Heddle 2003]. Figure 3-3 illustrates the impact of pipeline transport distance on the levelized cost of electricity of a retrofitted IGCC plant.

Figure 3-3 **Impact of distance of CO_2 Sequestration on COE for a retrofitted IGCC plant**



4 ECONOMIC AND ENVIRONMENTAL EVALUATION METHODOLOGY AND ASSUMPTIONS

A power producer's decision of whether or not to build a capture-ready coal-fired power plant will be determined by the expected costs and savings that would be attributable to a given design option. In addition, designs that minimize an owner's potential losses in the face of uncertain regulations will also be preferable. This is of considerable importance for CO_2 regulations, especially in the United States, as it is still unclear if, how and when emissions will be regulated.

For coal-fired power plants, pulverized coal technology appears to offer the lowest total costs if it is assumed that no steps will be taken to regulate CO_2 emissions during the lifetime of the plant. With the spectre of regulations possibly looming on the horizon (and already a reality in Europe), the preferred technology choice becomes unclear. A power plant constructed today will operate for many years, and may be subject to CO_2 regulations if and when these regulations are introduced.

The capture-ready options laid out in Chapters 2 and 3 involve additional investments or design compromises of one sort of another. These additional investments would not be economically justified unless there are expectations of incentives or costs that would provide an adequate level of savings or a revenue stream at some point in the life of the plant, or reduce the owner's potential exposure to the risk of losses in the face of uncertain regulations. Two scenarios that are currently being discussed by academics and policymakers that would provide the required incentive for a power plant owner to construct a capture-ready plant are:

- A tax levied on the atmospheric emissions of CO_2 (also known as a carbon tax)
- Caps or restrictions on allowable levels of CO_2 emissions, either from a facility by facility basis, or from a cap and trade system where owners could buy and sell emissions credits, depending on their ability to reduce their emissions.

Both options have been considered as mechanisms to limit CO_2 emissions; the European Union has set up the EU Emissions Trading Scheme, which provides a cap of emissions for major industrial emitters, covering approximately 40% of the total EU CO_2 emissions. The sources covered under the trading scheme include energy users of over 20 MW-thermal capacity, refineries, mining and smelting, and pulp and paper producers [Cantor Fitzgerald, 2006]. The Emissions Trading Scheme began in 2005, and has already established market prices for CO_2 emissions in Europe. Prices have been as high as $40 USD, but as of May 10, 2006 have dropped to below $15 USD [Point Carbon, 2006]. It will take some time before a clear picture forms on where carbon prices will head under a carbon cap and trade scheme.

CO_2 taxes have also been employed in some jurisdictions to reduce CO_2 emissions. Norway, which is not part of the European Union, has had a CO_2 tax scheme in place since 1991, and has led to the deployment of CO_2 capture and sequestration on a limited scale, namely the Statoil Sleipner offshore platform [EIA 2006]. This project sequesters CO_2 that is separated from the natural gas produced at the offshore platform. The CO_2 is re-injected into a saline aquifer instead of being released to the atmosphere. The tax level is sufficient to make this process economical, and has not required any subsidies or other regulations from government to be undertaken.

In the US, both mechanisms have been considered to control CO_2 emissions. Many northeastern states have recently signed into agreement the Regional Greenhouse Gas Initiative (RGGI). RGGI, which is still in the process of being implemented and will set up a regional cap and trade system for the participating states [RGGI 2006]. Many leading policymakers and academics have suggested the use of CO_2 taxes to control emissions, and have suggested initial levels and growth rates for the taxes. Some of the leading proposals include [Sekar 2005a]:

- McCain-Lieberman. An MIT analysis in 2003, when the bill was brought to the Senate suggested that the bill would cost \$10.82/t CO_2 in 2015, with an annual growth rate of 5.25%
- National Commission on Energy Policy in 2004 proposed emissions caps that would yield a maximum price of \$7/ton CO_2 in 2015, with a annual growth rate of 5%.
- Nordhaus and Boyer in 2000 proposed a policy that estimated compliance costs at \$4.1/ton $CO_{2,}$ increasing annually at a rate of 2.3%
- Barnes in 2001 recommended that the US implement Kyoto-like obligations, but with a safety vale on costs of \$7 /ton CO_2. Sekar et al. assumed a real annual growth rate of 2.3%.
- Kopp in 2001 recommended as an alternative to Kyoto that the US adopt a compliance payment of \$16.2 /ton CO_2. Sekar et al. assumed a real annual growth rate of 2.3% for this case, as well.

In addition, several major power companies have estimated carbon tax scenarios in order to inform their decision-making under the spectre of regulatory uncertainty. These companies include AEP and Southern Company, both large, investor-owned US utilities with a large installed base of coal-fired power plants, and plans to build more units in the near future.

A final benchmark that can be used to inform the decision-making process is the carbon tax levels that have been estimated by leading organizations that would be required to ensure that atmospheric levels of CO_2 do not exceed certain levels. MIT's Joint Program on the Science and Policy of Global Change has estimated the level of carbon tax required to meet three different CO_2 stabilization scenarios. The analyses is based on an annual growth rate of 4%, and estimated the initially required tax levels to be 62.9, 18.3, 7.2 and 4.3 \$/t CO_2 for stabilization scenarios of 450, 550 and 750 PPM, respectively [Sekar 2005b].

Both the tax and cap-and-trade mechanisms provide a monetary value for reducing CO_2 emissions, and both could be effective. On a single plant or on a single corporation scale, both provide a similar monetary incentive to reduce CO_2 emissions.

4.1 Analysis methodology

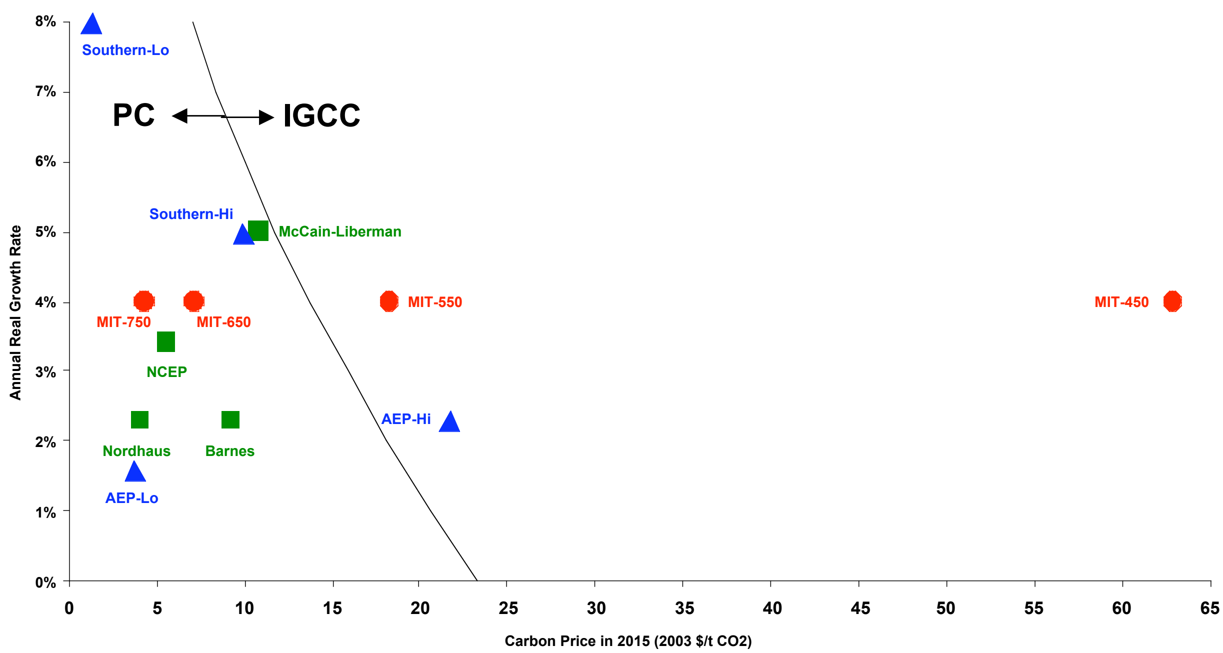
Previous work

A previous MIT Study [Sekar 2005b] performed an economic analysis to determine what CO_2 tax levels and growth rate scenarios are necessary to justify the selection of an alternative technology coal-fired power plant, namely IGCC. Two technology options were modelled in this analysis – a sub-critical PC plant, and an IGCC plant with a ConocoPhillips gasifier. The cost and performance numbers were developed from EPRI and National Coal Council [EPRI 2002, NCC 2002]. The selected cases assumed that an IGCC plant would initially be more expensive to build and operate, but would be less expensive to retrofit for CO_2 capture. In addition, it assumed that the PC plant would experience more output de-rating, and would require a larger make-up plant to accommodate the decreased ouput from the plant after the retrofit was complete. The costs of retrofitting the plant were estimated to be the difference in costs between a greenfield without capture and a greenfield capture plant. No accommodations were made to account for the increased de-rating and additional capital costs that would be incurred by retrofitting a plant for capture. In addition, no pre-investment in capture-ready was considered, beyond the inherent retrofit advantages that an IGCC plant is expected to have over a PC plant.

The study modelled a carbon tax to begin in 2015, increasing at a constant percentage, compounding annually. The year of retrofit for each technology case, carbon tax level and escalation rate was determined iteratively to select the year of retrofit that would minimize the lifetime net present value (NPV) costs of operating the plant. The analysis also accounted for the costs of capturing, compressing, transporting and sequestering the

CO_2. In all cases it was assumed that the plants were built in 2010. Figure 4-1 illustrates the results of this analysis.

Figure 4-1 Benchmark future carbon tax regimes vs. optimal technology choice [Sekar 2005]



The line on the chart represents the required expectation of initial carbon tax level and growth rate that would be required to justify investing in an IGCC plant. In addition, a number of the carbon tax scenarios discussed earlier in Section 4 are plotted for reference. These results indicated that the majority of carbon price scenarios do not support the construction of IGCC plants.

Current study

This thesis has expanded upon the economic analysis performed by Sekar et al. in three major ways. First, a comprehensive set of numbers has been developed that better characterize the costs and de-rating of retrofitting a plant for CO_2 capture, as well as the performance and operating costs of the plant after retrofit. This was done for both the PC and IGCC technologies. Second, the analysis adds a second IGCC case that includes additional investments in capture-ready technologies. These pre-investments reduce both the capital costs of retrofitting, and the expected de-rating of the plant after the retrofit is complete. The pre-investments considered include oversizing the gasifier and the air separation unit.

The final expansion of this analysis is the evaluation of the lifetime emissions of a plant, and provides guidance to policymakers on whether or not the issue of CO_2 'lock-in' is a concern for coal-fired power plants that will be built in the near future. CO_2 'lock-in' occurs when a newly constructed plant is so expensive to retrofit that it becomes uneconomic under the expected range of CO_2 tax levels to ever retrofit the plant for CO_2 capture. This is of particular concern for policymakers as the power plants being built now are expected to be operating for 40 years or more, and without retrofitting these plants, assuming a size of 500 MW_e and it is estimated that they will have total emissions of over 100 Mt during their lifetime. This is is a significant amount of $CO_{2,}$ equal to approximately 2% of the current annual CO_2 emissions of the United States. Multiply this by the 106 GW additional coal-fired capacity that is forecasted to be added to the fleet in the United States in the next 25 years and these plants represent a very significant, long-term new source of CO_2 emissions.

The alternative is the scrapping or complete rebuilding of these plants, which would result in the stranding of significant amounts of capital, exposing owners to large balance sheet write-offs. This may cause significant difficulties for policymakers to force the closing of these plants, as these closings could cause large increases in consumers' electricity pricing that would be necessary to cover the costs of sourcing alternative generation capacity.

The model used in this study calculated the NPV costs for each case, under a range of retrofit years and carbon tax scenarios. The NPV costs included the costs of building and retrofitting the plant, fuel and operation and maintenance (O&M) costs, as well as the costs of paying for the carbon taxes for the emissions from the plant. Each case assumed that the plant would begin to operate in 2010, with a carbon tax beginning in 2015. Three cases were evaluated, and the following variables were considered in the model:

- Year of retrofit
- Initial carbon tax level
- Carbon tax rate of increase
- Capital, O&M and fuel costs for the plant, before and after retrofit

The optimal year of retrofit (or no retrofit) was determined for each case under each carbon tax scenario by determining which year of retrofit gave the lowest NPV costs. The three cases evaluated in this study are described in the following subsections.

Baseline PC plant

The technology selected for the baseline PC plant in this study is supercritical PC. This technology was selected because it is the base case that was used in the MIT Coal Study, and appears to be the most likely of the advanced PC technologies to be constructed in the near term in the US. Supercritical plants have already been constructed throughout the world, and several have been proposed for construction in the United States. The plant is also assumed to have advanced pollution control, with both SCR for NO_X control and FGD for SO_2 control.

The plant is expected to have an output de-rating of 30.4%, which is significantly higher than either of the two IGCC cases shown below. This de-rating was calculated by assuming that the CO_2 compression and pumping energy costs would be the same as in a greenfield plant, but the heat requirements for the CO_2 re-boiler would be 50% higher. Using this methodology, the expected de-rating is 30.4%, which is higher than the 33.0% that was estimated in the MIT Coal Study, but is believed to better represent the expected efficiencies of the CO_2 capture technologies that have recently been proposed in the literature.

Baseline IGCC plant

The baseline IGCC plant was assumed to be a high pressure 6.20 MPa GE/Texaco gasifier with radiant and water quench gas cooling and an F-class combustion turbine. It also has a Selexol acid gas removal system. This is the same plant design that is specified as the baseline no-capture IGCC plant in the MIT Coal Study [MIT 2006]. The plant is expected to have an output de-rating of 18.8%, which is significantly lower than the de-rating of the PC plant, but higher than the IGCC plant with pre-investment.

IGCC with pre-investment plant

The IGCC with pre-investment design that was selected for this study is similar in design to baseline IGCC plant, except the air separation unit and gasifier are oversized by approximately 10% during the initial construction phase. Before the retrofit, the efficiency and marginal operating costs are expected to be the same as the baseline IGCC plant. The output de-rating values and the pre-investment costs were taken from the EPRI Phased Construction Report [EPRI 2003]. Once the retrofit is complete, the pre-investment reduces the output de-rating of the plant as compared to the baseline case by 4.8 percentage points to 14.0%.

Table 4-1 Performance characteristics of evaluated cases before and after retrofit

Case	Baseline PC plant	Baseline IGCC plant	IGCC with pre-investment plant
Technology	Supercritical PC	GE/Texaco gasifier with water quench	GE/Texaco gasifier with water quench
Before retrofit			
Output (MW_e)	500	500	500
Efficiency (%, HHV)	38.5%	38.4%	38.4%
CO_2 emissions (t/MWh)	0.83	0.84	0.84
After retrofit			
Output de-rating (%)	30.4%	18.8%	14.0%
Output (MW_e)	348	406	430
Efficiency (%, HHV)	26.8%	31.2%	31.2%
CO_2 emissions (t/MWh)	0.12	0.10	0.10
CO_2 captured (t/MWh)[6]	1.08	0.93	0.93

4.1.1 Investment costs

The costs of retrofitting a plant for CO_2 capture are significantly higher than the difference in total plant costs between a greenfield no-capture and capture plant. The reasons for the difference include:

- Two separate construction phases are required, with the associated additional planning, and contracting requirements.
- Some of the existing equipment may need to be modified or replaced, increasing the total amount of capital invested in the plant.
- The layout of the plant will not have been optimized for the addition of capture equipment, requiring compromises in the design and associated extra costs.
- The components of the plant may be mismatched after the retrofit, decreasing the efficiency of the plant after retrofit relative to a greenfield capture plant.

With these factors in mind, this study developed a set of numbers for the costs of the initial construction and subsequent retrofitting of a PC plant, baseline IGCC plant and

[6] *A capture efficiency of 90% is assumed in each case.

IGCC plant with pre-investment for capture-readiness. The investment costs are based on a number of recently published studies that have been summarized in Chapters 2 and 3. The costs were estimated for a plant with 500 MW_e output before retrofit.

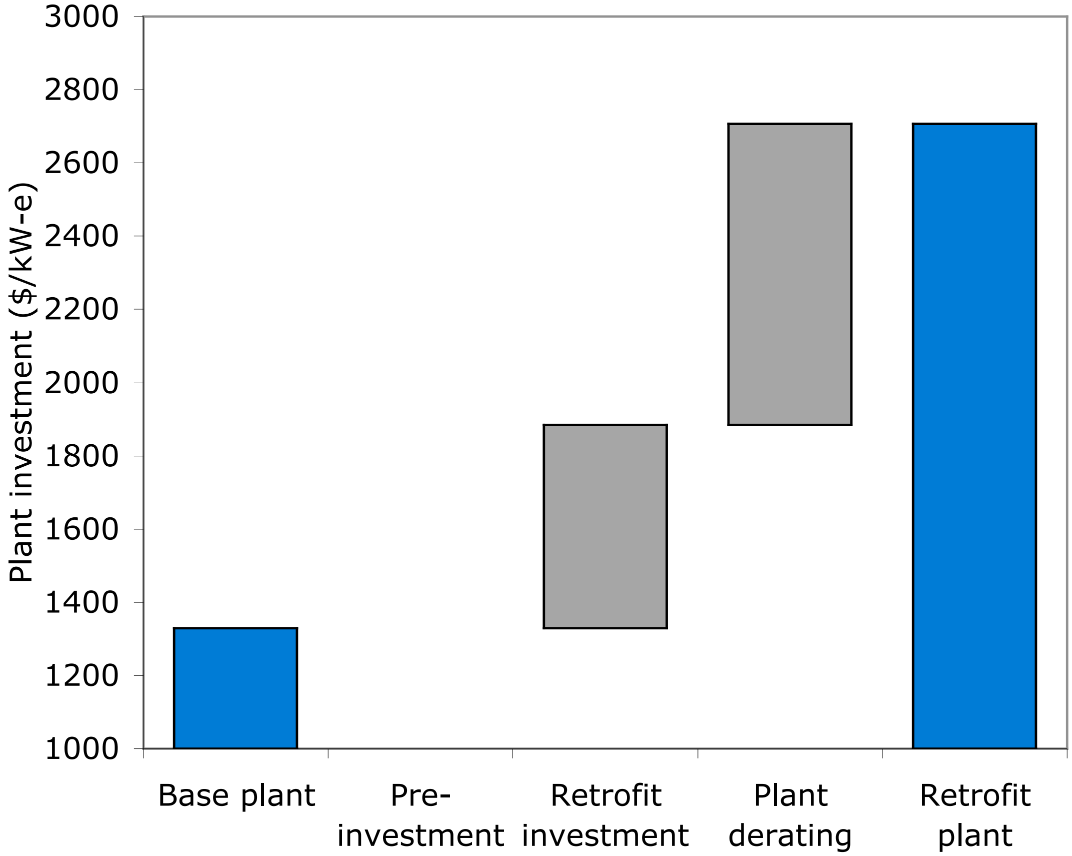
Baseline PC plant

The costs of retrofitting a PC plant per kW_e of net electrical output are expected to be significantly higher than for retrofitting an IGCC plant. The amount of equipment required to add the capture equipment are greater than in an IGCC plant, and the greater de-rating of a PC plant compounds this impact. Few studies have evaluated the costs of retrofitting PC plants. One major study was completed by Alstom which estimated the costs of retrofitting a subcritical PC plant [Parsons 2002]. This study considers the retrofit of a 434 MW plant with a post-combustion MEA separation system, and the entire retrofit is estimated to cost 409 M$, or 1604 $/kW_e$. This corresponds to an increase in the incremental cost for the capture equipment of 70% when compared to a greenfield sub-critical plant, which adds 950 $/ kW_e$ to the cost of the baseline plant [MIT 2006].

This study is evaluating the costs of retrofitting a supercritical plant. In order to estimate the capital costs of the retrofit, it is assumed that the retrofit will cost 70% more than the incremental increased capital needed for a greenfield plant. The MIT Coal study estimates that the increased capital of building a greenfield supercritical plant with capture is 810 $/kW_e$, which correlates into an incremental cost of retrofitting the plant of 1377 $/kW_e$ for this study.

Figure 4-2 illustrates the impact on total plant cost of retrofitting a supercritical plant with post-combustion retrofit.

Figure 4-2 Impact of retrofit on total plant cost for supercritical PC plant with post-



combustion capture[7]

Baseline IGCC plant

The most comprehensive study to date on capture-ready for IGCC was performed by EPRI and reported in the Phased Construction Report [EPRI 2003]. In this study, EPRI evaluated the impact of pre-investment on the performance and economics of IGCC plants with both a GE/Texaco gasifier with water quench gas cooling and a ConocoPhillips E-gas gasifier with radiant and convective gas cooling. Each plant design was evaluated for retrofit for both a baseline and pre-investment for capture case.

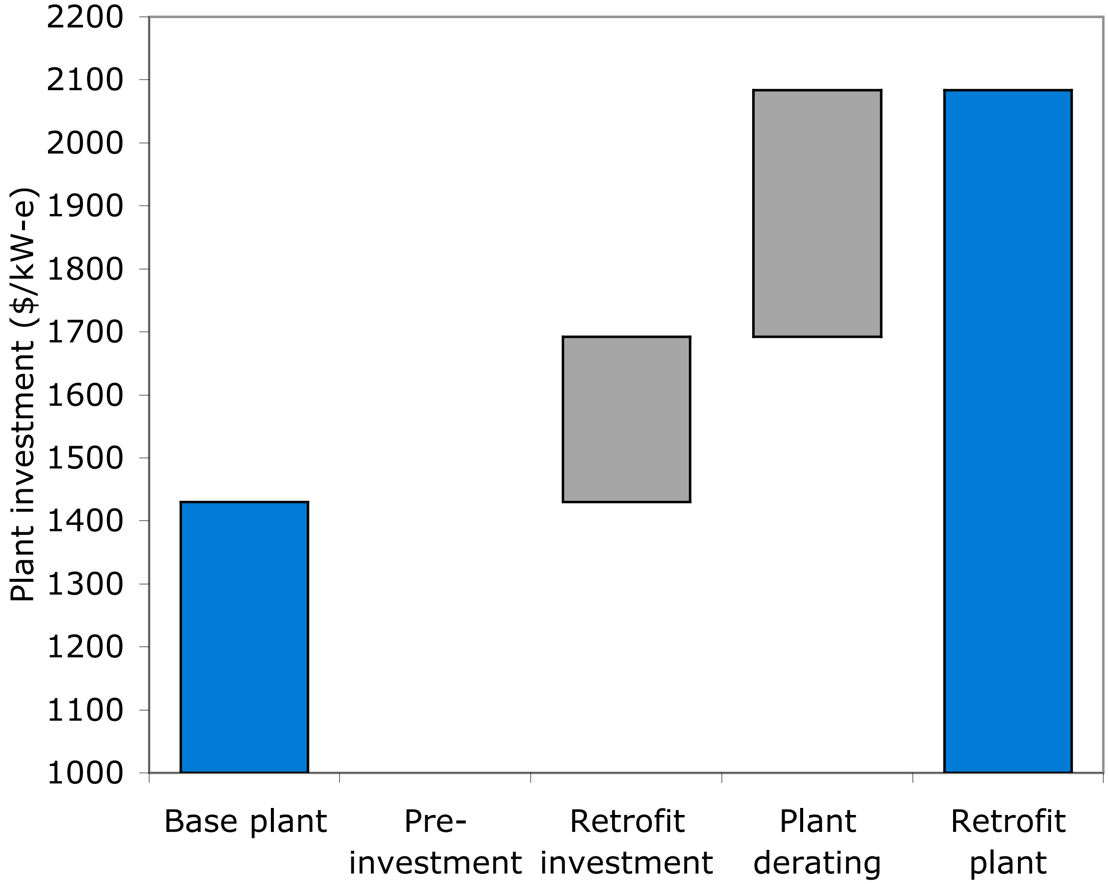
[7] Note: the costs of de-rating are calculated as the difference in per kWe costs of the total investment divided by the output before de-rating, and the total investment divided by the output after de-rating.

For this evaluation, a base case IGCC case was developed in consulting both the EPRI report, and the upcoming MIT coal study [MIT 2006]. The baseline IGCC plant for this study is a GE/Texaco gasifier with radiant and quench gas cooling. The plant is optimized for no capture, with the size of the gasifier and air separation unit matching the heat input requirements of the combustion turbine, and no accommodations to make up for the reduction in heat rate input to the combustion turbine after retrofit. The capital costs for this case were taken from values from the MIT coal study.

To estimate the costs of the retrofit, it was assumed that the radiant gas cooler would no longer be necessary, and would be scrapped during the retrofit. This adds 150 \$/ kW_e to the cost of the retrofit over a greenfield capture plant, which would have specified only a water quench cooling system [Holt 2004]. In addition, the mismatch between the gasifier/ASU and combustion turbine results in a greater de-rating than the greenfield plant, and adds 44 \$/ kW_e to the capital costs [EPRI 2003]. The retrofit costs were estimated in this manner, and not taken directly from the EPRI report because it is believed that this study systematically underestimated the retrofit costs.

Figure 4-3 illustrates the impact on total plant cost of retrofitting a baseline IGCC plant. Complete details on the costs and de-rating for the plant are provided in Table 4-2.

Figure 4-3 **Impact of retrofit on total plant cost for baseline IGCC plant**



IGCC plant with pre-investment

The second case specified an oversized gasifier and air separation unit, which will allow the combustion turbine to run at full load after the retrofit, with a much smaller output de-rating than the baseline IGCC case. As in the baseline IGCC case, the capital costs for this case was developed from values from the MIT coal study. This pre-investment adds 59 \$/ kW_e to the cost of the baseline no-capture plant, but reduces the cost of the retrofit by 103 \$/ kW_e. Figure 4-4 illustrates the impact of a retrofit on the capital costs of an IGCC plant with pre-investment. Complete details of the costs and de-rating of the IGCC plant with pre-investment are provided in Table 4-2.

Figure 4-4 Impact of retrofit on total plant cost for IGCC plant with pre-investment

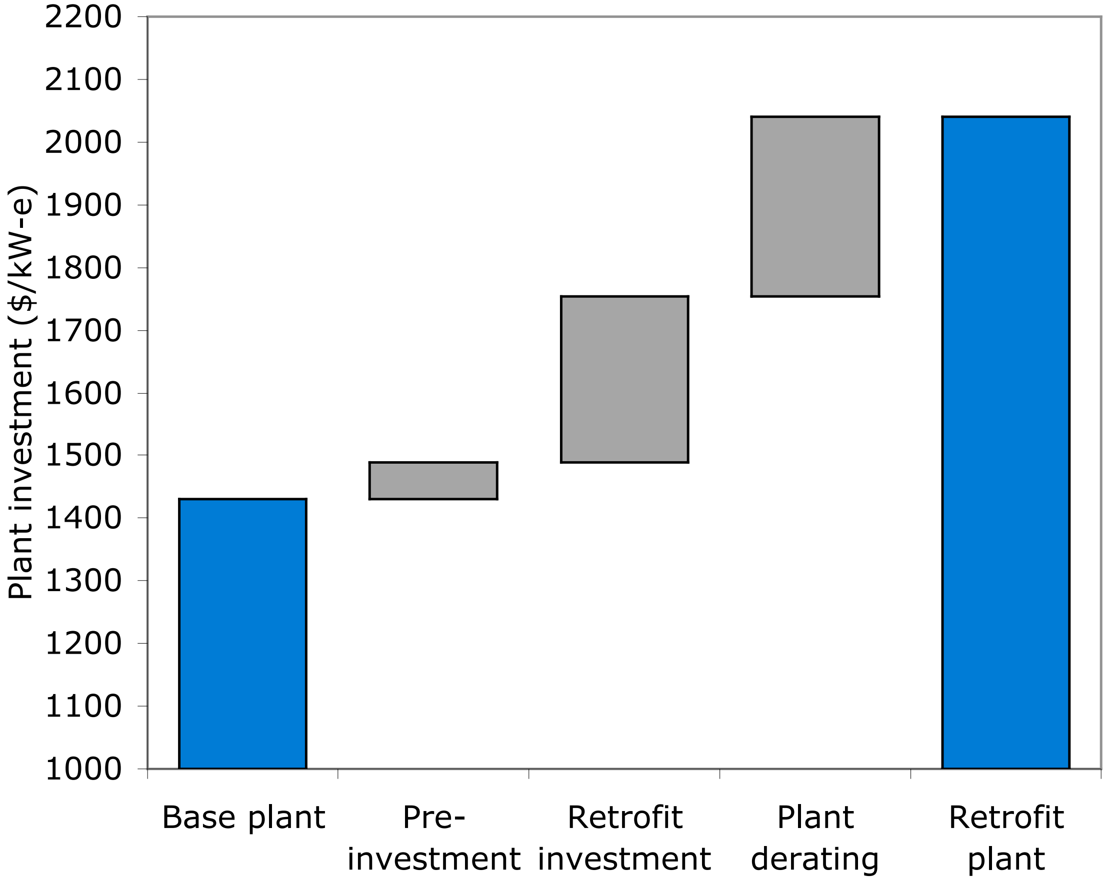


Table 4-2 Capital costs, operating costs and performance of cases before and after retrofit

Case	Baseline PC	Baseline IGCC	IGCC with pre-investment
Before retrofit			
Net output (MW_e)	500	500	500
Total plant cost (M$)	665	715	745
Total plant cost ($/k$W_e$)	1330	1430	1489
After retrofit			
Net output (MW_e)	348	406	430
Retrofit total plant cost (M$)	201	131	133
Total plant cost after retrofit ($/k$W_e$)	2707	2084	2040

4.1.2 Operation and maintenance costs

The operation and maintenance costs were taken from the MIT coal study [MIT 2006] for both the pre- and post-retrofit cases. These values were selected over the values in the Alstom and EPRI studies in order to ensure consistency between the IGCC and PC cases, as the O&M costs are dependent on a number factors external to the design of the plant, including labor and material costs, which can vary significantly depending on the selected location of the plant and the year in which the study was performed. Table 4-3 outlines the values for operation and maintenance that were used in this study.

Table 4-3 Operation and maintenance costs for study cases

Technology	Supercritical PC	Baseline IGCC	IGCC with pre-investment
O&M – before retrofit ($/MWh)	7.5	9.0	9.0
O&M- after retrofit ($/MWh)	16.0	10.5	10.5

4.1.3 Fuel costs

The coal used in this study was assumed to be Illinois #6 sub-bituminous coal which is consistent with the coal that was specified for the MIT study, and similar to the Pittsburg #8 coal specified in the EPRI report. The cost of this coal is assumed to be 1.50 $/MMBtu, HHV.

4.1.4 Makeup plant

All three of the cases that are evaluated in this study require that additional power be provided to make up for the output de-rating that occurs during the retrofit. The amount of makeup power varies in each case, however. The baseline PC plant requires 143 MW_e, the baseline IGCC plant requires 75 MW_e, and the IGCC with pre-investment plant requires 51 MW_e. The costs and performance of the makeup plant are taken from the MIT study. For the supercritical case it is assumed that a greenfield supercritical plant was constructed. For the IGCC case it is assumed that a greenfield GE/Texaco IGCC plant is constructed. The details of the makeup plant are listed in Table 4-4.

Table 4-4 Costs and performance of greenfield makeup plants

Case	Baseline PC	Baseline IGCC	IGCC with pre-investment
Technology	Supercritical PC	GE/Texaco with water quench	GE/Texaco with water quench
Net output (MW_e)	152	94	70
Efficiency (%, HHV)	29.3%	31.2%	31.2%
Total plant cost ($/$kW_e$)	$2140	$1890	$1890
Total plant cost (M$)	325	178	132
O&M costs ($/MWh)	16.0	10.5	10.5

4.1.5 Economic parameters

The choice of economic parameters can have a significant impact on the optimal selection of technology. The same economic parameters that were used in the Sekar analysis were used in this work. Table 4-5 outlines these parameters.

Table 4-5 Economic arameters used for modeling

Economic parameter	Value
Discount rate	6.0%
Inflation rate	2.5%
Capacity factor	80%
Fuel cost ($/MMBtu, HHV)	$1.50
Net output (MW_e)	500
Tax rate	40%
Depreciation rate (annual on remaining capital)	30%
Insurance and property tax rate	1.78%
CO_2 transporation and sequestratrion cost ($/t CO_2)	$5.00

4.1.6 Modeling inputs

Table 4-6 summarizes the inputs to the NPV model for each case that was evaluated for this study.

Table 4-6 Modeling inputs

Technology	Baseline PC	Baseline IGCC	IGCC with pre-investment
Investment costs			
Initial investment (M$)	665	715	745
Retrofit and makeup investment (M$)	602	309	265
Before retrofit			
Capital costs (M$)			
Fuel costs (M$/yr)	46.6	46.7	46.7
O&M costs (M$/yr) (excludes carbon tax)	26.3	31.5	31.5
CO_2 emissions (MT/yr)	2.9	2.9	2.9
After retrofit			
Fuel costs (M$/yr)	65.2	57.5	57.5
O&M costs (M$/yr) (excludes carbon tax)	56.1	36.8	36.8
CO_2 emissions (MT/yr)	0.41	0.36	0.36
CO_2 sequestered (MT/yr)	3.7	3.2	3.2

5 RESULTS OF ECONOMIC AND ENVIRONMENTAL EVALUATION

As mentioned in section 5, the evaluation for this analysis involved both the calculation of the net present value (NPV) costs and an optimal year of retrofit for three modeled cases, under a range of carbon tax level and growth scenarios. Appendix A provides examples of these calculations. It is important to note that the calculations were done assuming a net electrical output of 500 MW_e, with a second greenfield capture plant of the same technology as the retrofitted plant (supercritical PC or IGCC) being constructed at the time of retrofit to make up for the net reduction in output.

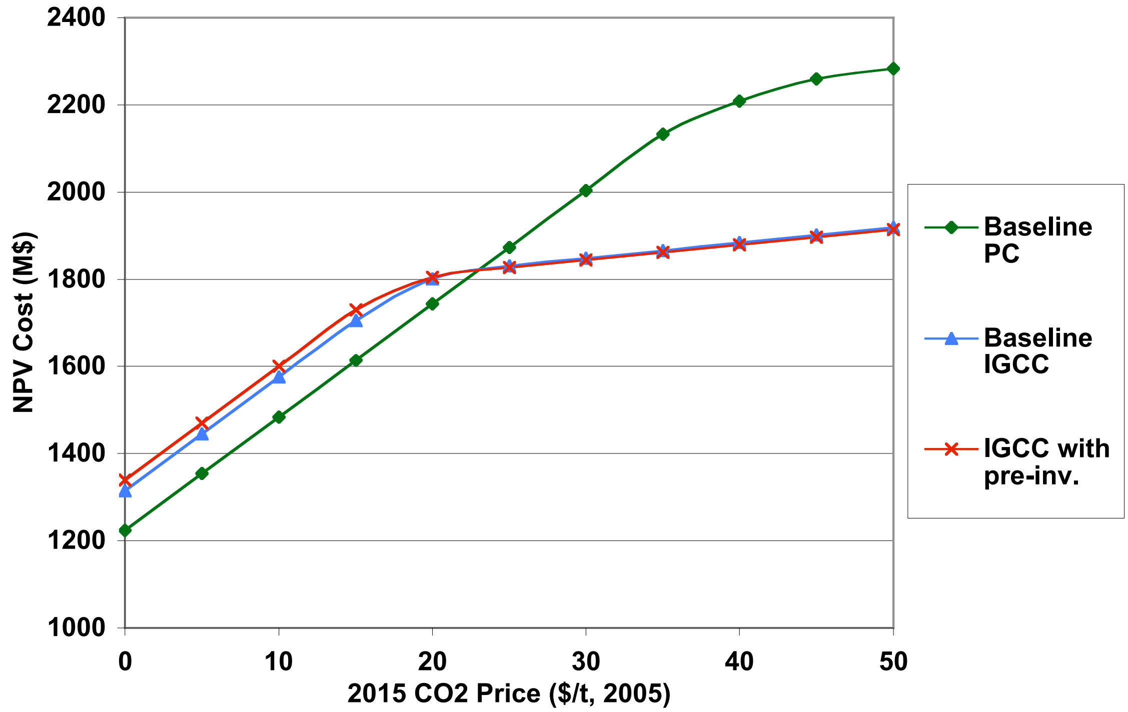
Three different economic and environmental evaluations were done for this study. The first analysis evaluated which technology was economically preferable under a given carbon tax scenario. The second analysis evaluated the year of retrofit that would be expected under these scenarios. The final analysis evaluated the expected lifetime emissions from each of the scenarios. The following three sections outlines the results of these analyses.

5.1 Optimal technology choice for a given carbon tax scenario

Under the scenario where no carbon tax is expected during the life of the plant, the baseline PC case is the preferred technology option, followed by the baseline IGCC plant, and then the IGCC with pre-investment plant. This was expected because without an economic incentive (the carbon tax) there would be no incentive to make additional investments in a plant that had lower retrofit costs, because there is no incentives for the retrofit to occur.

This situation changes once a carbon tax is implemented. To illustrate the impacts of a carbon tax, the following graph illustrates this impact on a plant under a range of initial carbon tax scenarios, with an assumed growth rate in tax of 2% per year, compounded annually.

Figure 5-1 40-year NPV cost of plant vs. initial carbon tax level – 2% tax growth rate

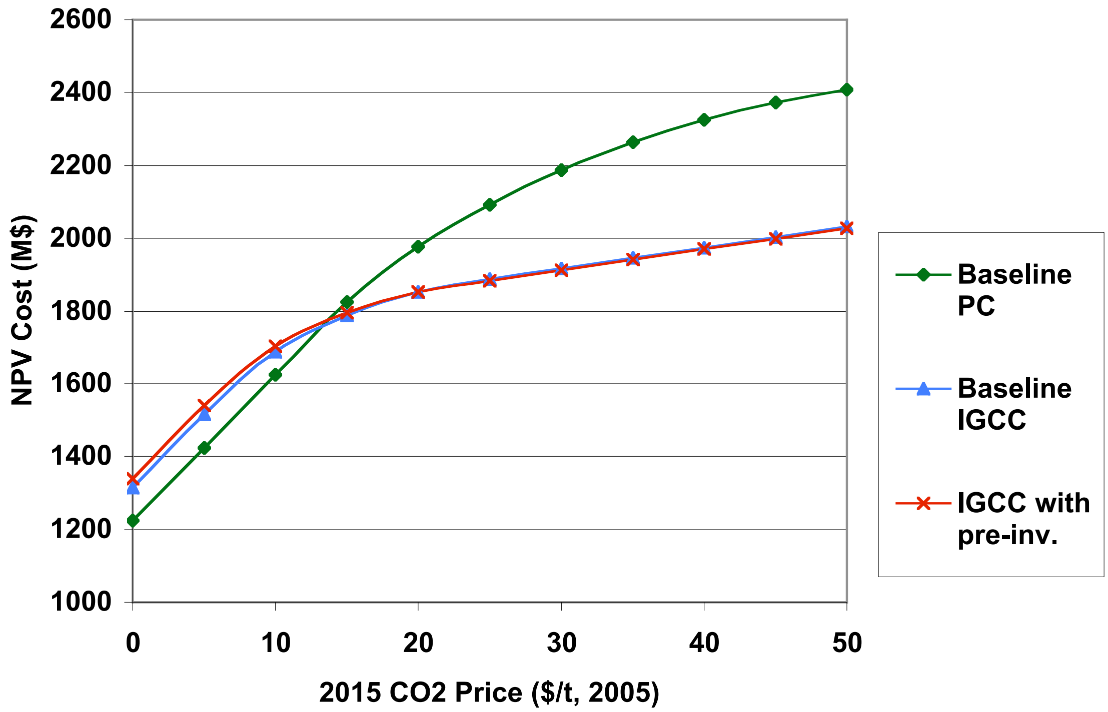


Under this scenario, the baseline PC case is the most economic choice for the owner unless the carbon tax is expected to exceed 22 \$/t CO_2. The difference is relatively small, however, with the lifetime NPV cost difference between baseline IGCC plant and the baseline PC never exceeding 91 M\$ or 7% of the total NPV cost For a IGCC with pre-investment plant the differences are slightly higher, but still relatively small compared to the lifetime NPV costs of the plant. The lifetime NPV cost of the IGCC with pre-investment plant never exceeds 117 M\$, or 10% of the total.

In the event of high (exceeding 22 \$/t CO_2) initial carbon tax level, the advantages of both the baseline and IGCC with pre-investment plant becomes significant. The advantage at an initial tax rate of 50 \$/t CO_2 equating to a decrease in NPV costs for the baseline IGCC case of 365 M\$ or 16% of the lifetime NPV costs. The IGCC with pre-investment has a marginally greater advantage, saving 270 M\$ over the lifetime of the plant, or 17% of the lifetime NPV costs.

In the event of higher tax growth rates, the initial tax level required for an IGCC plant (baseline or capture-ready) to be the economically preferred option drops significantly, to 13 \$/t CO_2. Figure 5-2 illustrates the impact of the higher tax growth rate on the lifetime NPV costs of the cases that were evaluated in this study.

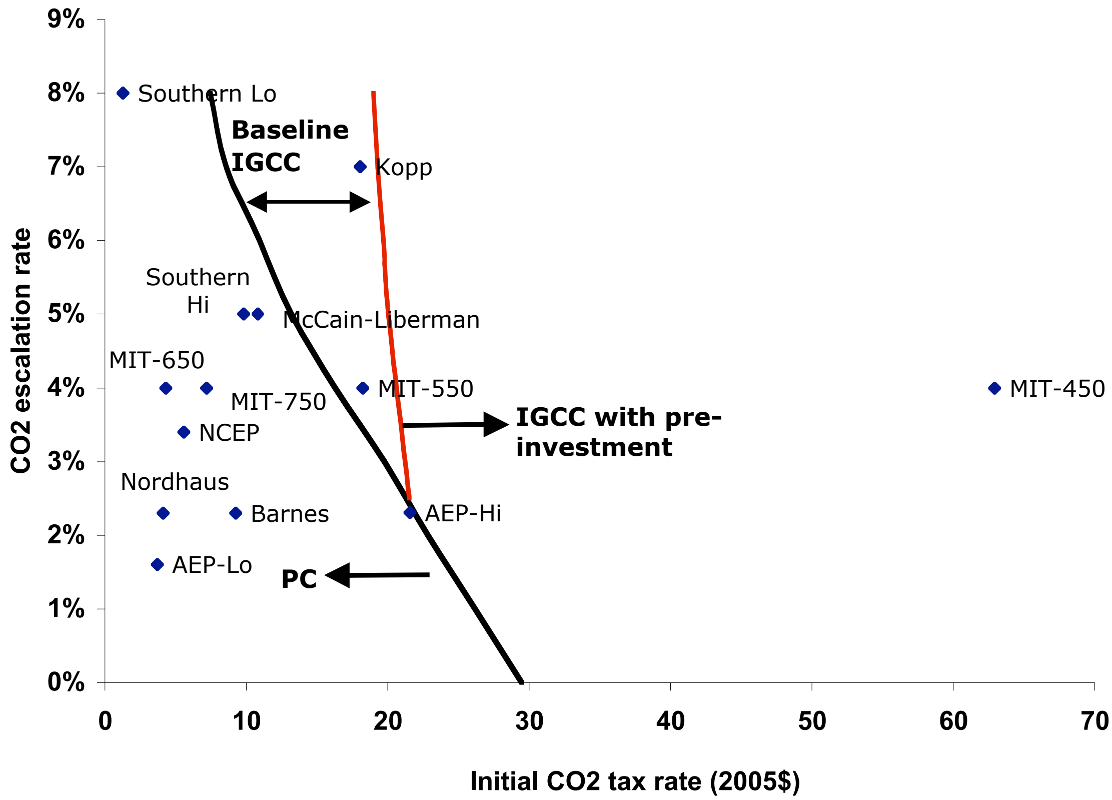
Figure 5-2 40-year NPV cost of plant vs. initial carbon tax level – 5% tax growth rate



In both cases, the IGCC plant with pre-investment does not have significant lifetime NPV savings (or costs) when compared with the baseline IGCC plant.

By calculating the NPV costs for each technology under a wide range of initial carbon tax levels and growth rates, this study has developed a matrix that illustrates which technology choice is optimal. Figure 5-3 illustrates the results of this analysis.

Figure 5-3 **Economically optimal technology choice vs. future carbon tax regime**



The solid lines divide the areas on the matrix in which each technology choice is optimal. On the left-hand side a baseline PC plant is the optimal choice. On the right-hand side, a capture-ready plant is the optimal choice. Between the two, at the top of the chart, a baseline IGCC plant is the optimal technology choice. Which technology choice is optimal depends on the owner's expectations of future carbon tax levels and rates of increase.

5.2 Impact of technology choice on optimal year of retrofit

The second part of the analysis for this study evaluated the impact of technology choice and pre-investment on the expected year of retrofit. This analysis determined what the economically optimal year of retrofit is for each of the three cases under the full range of initial carbon tax levels and annual rates of increases. The model iteratively determines the optimal year of retrofit for each carbon tax scenario. This analysis is of importance because it provides guidance to owners regarding when they can expect that major investments will be necessary to retrofit their plants. It is also important in evaluating the expected lifetime CO_2 emissions of the plant, which has significant implications from a policy-making perspective

Figure 5-4 illustrates the impact of a CO_2 tax beginning in 2015, and increasing at a rate of 2%, compounded annually. This scenario illustrates that the year of retrofit of the PC case will be very late, if ever in the life of the plant, unless a very high tax rate is assumed. The IGCC plants will retrofit at a much earlier date, as long as an initial tax rate greater than 17 \$/t CO_2 exists.

Figure 5-4 Optimal year of retrofit vs. initial carbon tax level – 2% growth rate

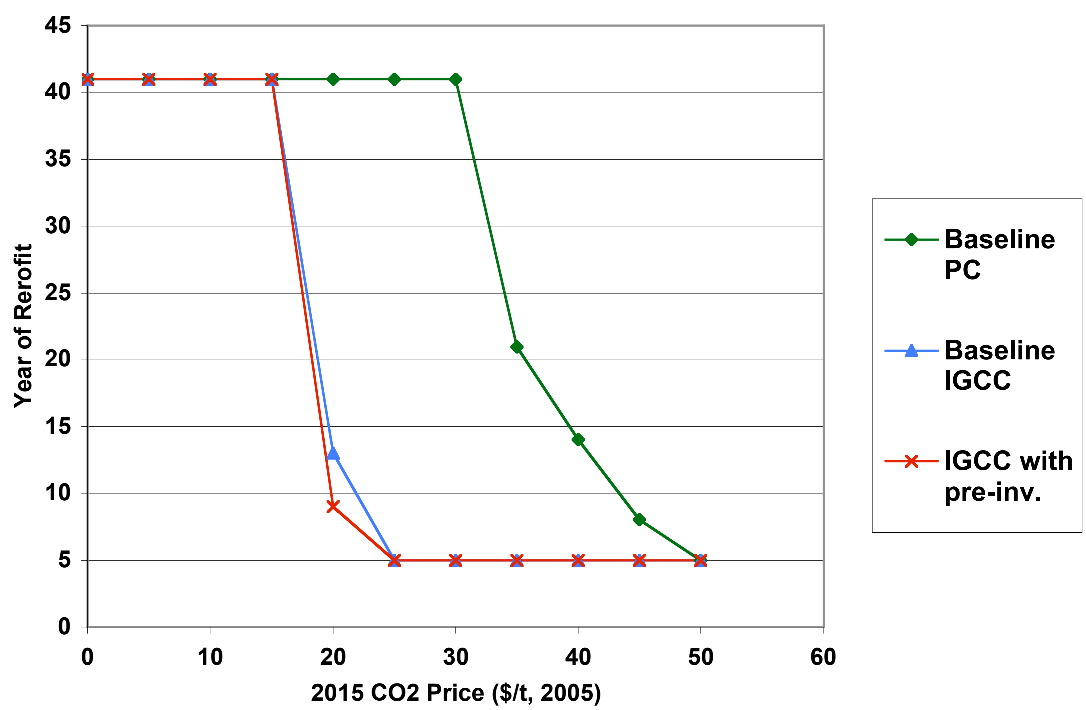
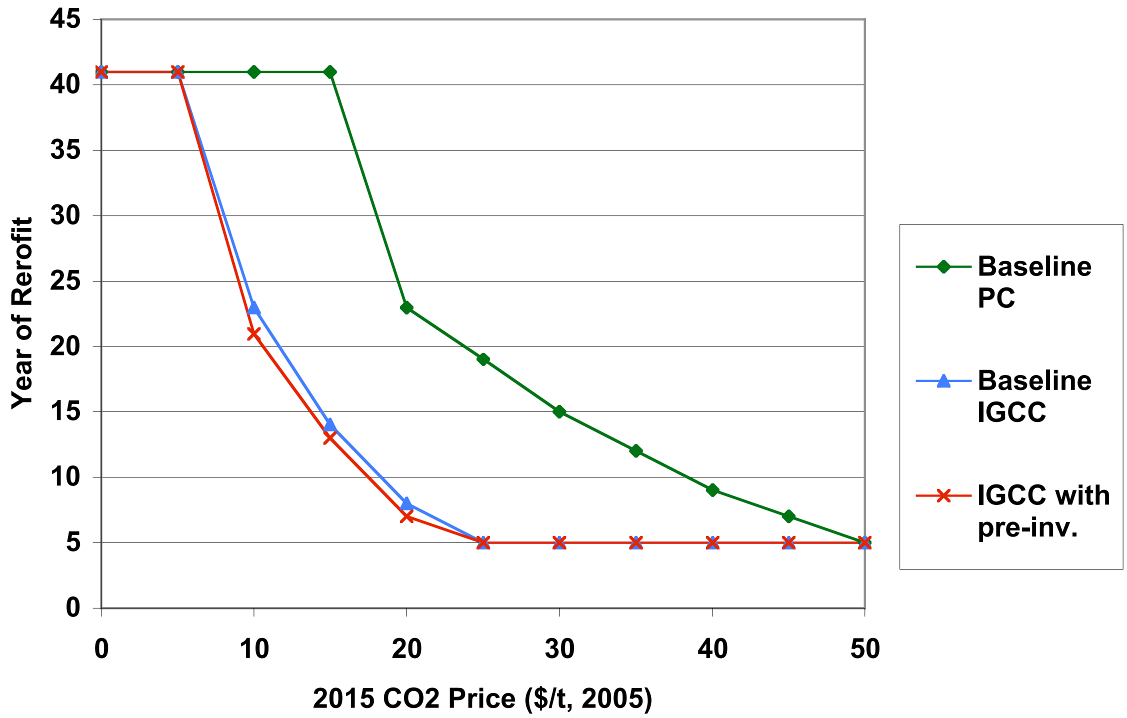


Figure 5-5 illustrates the impact of the technology choice on the year of retrofit at an assumed tax growth rate of 5%. Under this scenario, the PC plant is expected to retrofit at a much earlier date than at a lower carbon tax growth scenario, but it will still lag significantly behind the IGCC cases.

Figure 5-5 Optimal year of retrofit vs. initial carbon tax level - 5% growth rate



The results show that there are carbon tax scenarios where the year of retrofit is estimated to occur very late in the life of the plant, leaving only a few years for the plant to run before retrofitting. It is likely that this expected remaining lifespan would decrease the probability that the plant would in fact be retrofitted, as it may be more economical to invest in a new plant, or to rebuild the current plant to an optimized capture plant. Alternatively, the owner may decide to extend the life of the plant, possibly well beyond the 40 years assumed in this analysis.

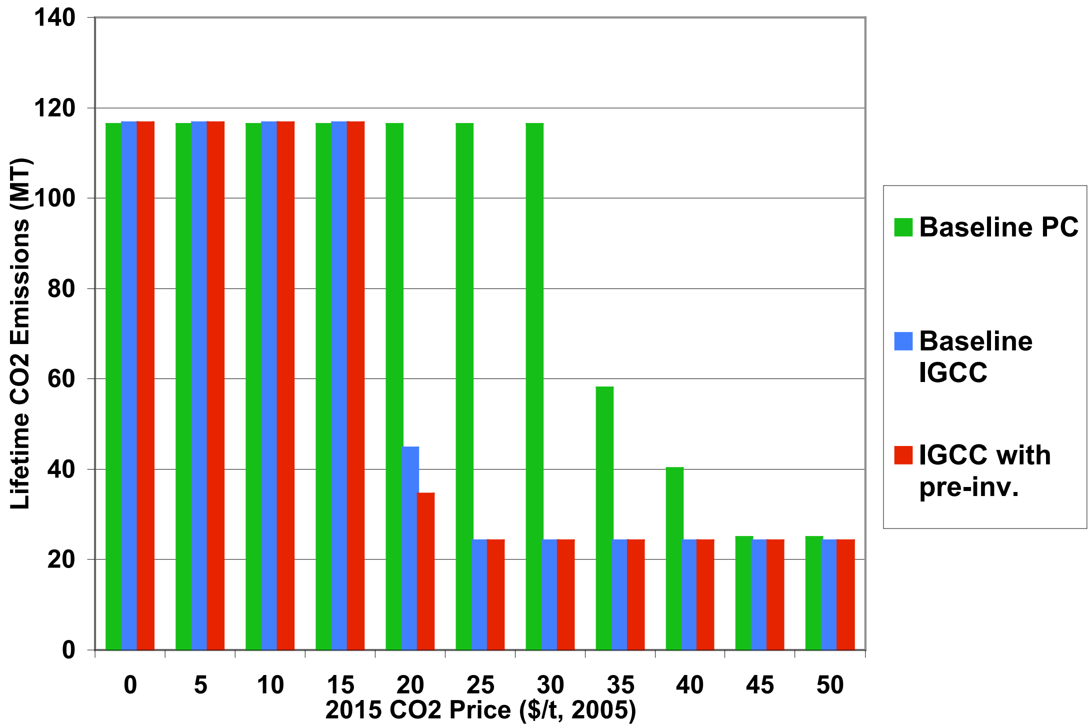
5.3 Impact of technology choice on lifetime CO_2 emissions

The lifetime CO_2 emissions of a plant are dependent on a number of factors, including the CO_2 emissions rate, the net electrical output, the expected de-rating of the plant after the retrofit, the year of retrofit, and the capture efficiency of the added CO_2 capture equipment. Each of these factors have been taken into account in the modeling performed for this study.

To determine the impact of the technology choice on the lifetime CO_2 emissions of the plant, the year of retrofit was determined for each case, as described in Section 6.2. The year of retrofit was then used to determine the lifetime CO_2 emissions, with higher emissions occurring before the retrofit, and much lower emissions occurring after the retrofit. Table 4-6 outlines the annual CO_2 emissions assumptions for each case, before and after the retrofit.

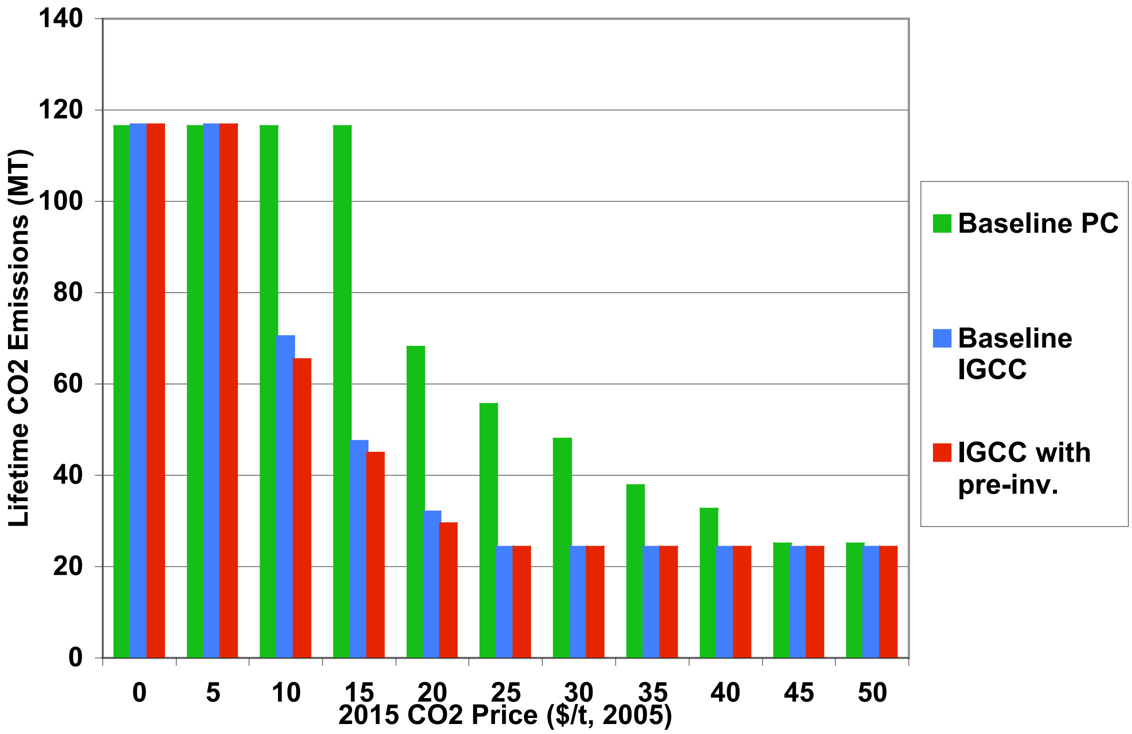
Figure 5-6 illustrates the impact of technology on lifetime CO_2 emissions for a 2% growth case. From this analysis, it can be seen that both IGCC cases will have much lower lifetime CO_2 emissions as long as carbon tax rates are expected to exceed 15 $/ton. Little difference in the year of retrofit is expected between the baseline and pre-investment IGCC cases.

Figure 5-6 Lifetime CO_2 emissions vs. initial carbon tax level – 2% growth rate



A higher carbon tax growth rate decreases the expected differential between IGCC and PC lifetime CO_2 emissions because the PC plants retrofit at an earlier date, but the difference between the two cases is still significant. Figure 5-7 illustrates the results for a carbon tax growth rate of 5%.

Figure 5-7 Lifetime CO_2 emissions vs. initial carbon tax level – 5% growth rate



These results provide significant insight into the concept of CO_2 'lock-in'. First, a high enough carbon tax rate (above 7 $/ton CO_2 for IGCC, and higher for PC) is required for lifetime CO_2 emissions to be reduced. In the case of a low CO_2 tax growth rate (2%) scenario, an IGCC plant is expected to have a very large (50-70%) reduction in lifetime CO_2 emissions if the initial tax rate falls within a moderate (20-35 $/ton CO_2) range. At tax rates above 35 $/ton CO_2 or below 15 $/ton CO_2, the difference in lifetime CO_2 emissions between the PC and IGCC plants are much closer. In the case of a higher CO_2 tax growth rate (5%) scenario, the difference in lifetime CO_2 emissions between the PC and IGCC plants is smaller but still significant, with a reduction in lifetime CO_2 emissions ranging from 30% at an initial tax rate of 10 $/ton CO_2 to less than 15% at 40 $/ton CO_2. There are insignificant differences between PC and IGCC at the higher (above 40) and lower (below 7) $/ton CO_2 initial carbon tax levels. Also, pre-investment for IGCC does not appear to give a significant economic advantage over a baseline IGCC plant.

6 CONCLUSIONS AND AVENUES FOR FUTURE WORK

6.1 Conclusions

The objective of this study, as described in Section 1.2 is to first explore and define the range of actions and investments that can be made during the construction of a coal-fired power plant to reduce the future costs and output de-rating of retrofitting a plant for CO_2 capture. The second part of the study evaluates under what scenarios these investments would make economic sense. It also evaluates the impacts on lifetime CO_2 emissions, as well as the concept of carbon 'lock-in' for these plants. The conclusions for each research objective are summarized below.

Question 1: *What are the range of capture-ready options and technologies for both IGCC and PC coal-fired power plants?*

A number of capture-ready options and technologies are available to an owner to consider during the initial design and construction phase of a plant. Described in detail in Sections 2.3 and 3.4, some of the leading capture-ready options for the technologies are:

Pulverized Coal

- Selecting a high-efficiency supercritical boiler design reduces the output de-rating and costs of the capture equipment during the retrofit.

IGCC

- Oversizing the gasifier and air separation unit to ensure that the combustion turbine will continue to operate under full load after the retrofit.

- Selecting a gasifier design with a high gasifier pressure, to reduce the energy costs of separating the CO_2 out of the syngas after the retrofit is complete.
- Selecting a turbine that has combustors that can be easily retrofitted for hydrogen gas combustion.

Both technologies

- Ensuring that sufficient space is left on the plant site, and the plant layout is developed with consideration for where capture equipment would have to be located during the retrofit, as well as the space required for the construction activities associated with a retrofit.
- Locating the plant close to a suitable sequestration site, and ensuring that the right of way to the site will be available when time to retrofit.

Question 2: *Under what carbon price scenarios does pre-investing in a capture-ready plant make sense?*

Under lower carbon tax pricing scenarios, it appears that investing in a capture-ready plant is not economical, although the difference in lifetime costs between a PC plant and an IGCC (with or without pre-investment for capture) is expected to be relatively small – 10% or less than the total lifetime costs of the plant. If, on the other hand, carbon tax levels are high (or even at the level that carbon credits that have recently been trading at in Europe) and IGCC plant as a capture-ready option is the preferred choice. Under certain scenarios the lifetime NPV costs of an IGCC plant can be as much as 15% lower than the costs of a PC plant. This may make an IGCC less risky for an investor who is unsure of where carbon prices are going to head, especially over the long lifespan of a plant that is to be built in the near future.

The value of the pre-investment for the IGCC case, at least as defined in this study, provided only a limited reduction in lifetime NPV costs as compared with the baseline IGCC case, and only under the higher carbon tax scenarios that were modeled.

Question 3: *Is carbon 'lock-in' a concern for PC coal-fired plants being built in the near future?*

IGCC plants have lower retrofitting costs, and therefore require significantly lower carbon tax prices in order to justify a retrofit. This moves forward the year of retrofit for an IGCC plant significantly, and correspondingly reduces the lifetime CO_2 emissions from the plant, when compared with a PC plant. PC plants require relatively high carbon prices in order to retrofit, and have correspondingly higher lifetime CO_2 emissions. The analysis in this study estimated that for a wide range of carbon price scenarios a PC plant could be expected to have 30%-60% higher lifetime CO_2 emissions than an equivalently sized IGCC plant, indicating that carbon lock-in is a significant issue for these plants. Also, pre-investment for capture-ready in an IGCC plant does not appear to have a large impact on the lifetime CO_2 emissions as compared to a baseline IGCC plant.

6.2 Avenues for future work

In many ways, this work has but scratched the surface of the options surrounding capture-ready plants, and much research is needed to fully understand all of the issues surrounding the technology and policy of this topic. Some avenues for future work include:

- Expanding the analysis of the pre-investment cases to include a PC plant. This may require a full engineering and economic analysis, as little work has been done to quantify the costs of building a capture-ready PC plant.
- The expansion of the IGCC cases to include other gasifier designs, such as the ConocoPhillips or Shell units, or units with different types of heat recovery, such as water quench only.
- A comparison of the NPV costs of a capture-ready plant with other generation options, such as building a greenfield capture plant from start, or the selection of other non-coal based technologies.

- A more rigorous evaluation of volatility by applying real options analysis to these cases, or performing a Monte Carlo analysis to account for volatility in a number of model inputs, including fuel price, CO_2 tax starting year, level and growth rates, electricity prices and costs of retrofitting.

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APPENDIX A SAMPLE NPV CALCULATIONS

Case 1 **PC Baseline**

Economic parameters	
Discount rate	6.0%
Inflation	2.5%
Capacity factor	80%
Fuel cost	1.50
Net output (MWe)	500
Tax rate	40%
Depreciation (annual)	30%
Insurance and property tax rate	1.78%
CO2 tax ($/t CO2, 2010)	25
CO2 tax growth rate (%)	5%
CO2 transp. & seq cost ($/t CO2)	$ 5.00

Scenario inputs	**Initial plant**	**Retrofit**
Investment (M$)	665	602.3
O&M cost (M$)	26.3	56.1
Fuel cost (M$)	46.6	65.2
CO2 released (MT)	2.9	0.4
CO2 captured (MT)	0.0	3.7

Retrofit year 19

Calendar year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2050**
Operation year	0	1	2	3	4	5	6	7	8	9	10	40
Investment costs (M$)												
Initial investment (M$)	$ (665.0)											
Retrofit Investment (M$)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation (M$)	$ -	$ 194.6	$ 132.9	$ 90.8	$ 62.0	$ 42.3	$ 28.9	$ 19.7	$ 13.5	$ 9.2	$ 6.3	$ 0.1
Operating costs (M$)												
Fuel	$ -	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)	$ (46.6)
O&M	$ -	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)	$ (26.3)
Insurance and property tax	$ -	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (11.8)	$ (22.6)
CO2 tax	$ -	$ -	$ -	$ -	$ -	$ (73.0)	$ (76.7)	$ (80.5)	$ (84.5)	$ (88.8)	$ (93.2)	$ (402.8)
CO2 transport and sequestration	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation & O&M tax shield	$ -	$ 111.7	$ 87.1	$ 70.2	$ 58.7	$ 80.0	$ 76.1	$ 74.0	$ 73.1	$ 73.1	$ 73.7	$ 199.3
Cash Flow (M$)												
Total cash flow	$ (665.0)	$ 27.0	$ 2.3	$ (14.5)	$ (26.0)	$ (77.7)	$ (85.3)	$ (91.2)	$ (96.2)	$ (100.4)	$ (104.2)	$ (298.9)
Discount factor	1.00	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.10
Discounted cash flow	$ (665.0)	$ 25.5	$ 2.1	$ (12.2)	$ (20.6)	$ (58.1)	$ (60.1)	$ (60.7)	$ (60.3)	$ (59.4)	$ (58.2)	$ (29.1)
CO2 tax rate						$ 25.0	$ 26.3	$ 27.6	$ 28.9	$ 30.4	$ 31.9	$ 137.9

Lifetime NPV cost (M$)	**$ (2,092.75)**
Lifetime CO2 emissions (MT)	**61.6**
Lifetime CO2 sequestered (MT)	**80.9**

Case 2 **IGCC Baseline**

Economic parameters	
Discount rate	6.0%
Inflation	2.5%
Capacity factor	80%
Fuel cost	1.50
Net output (MWe)	500
Tax rate	40%
Depreciation (annual)	30%
Insurance and property tax rate	1.78%
CO2 tax ($/t CO2, 2010)	25
CO2 tax growth rate (%)	5%
CO2 transp. & seq cost ($/t CO2)	$ 5.00

Scenario inputs	**Initial plant**	**Retrofit**
Investment (M$)	715	308.8
O&M cost (M$)	31.5	36.8
Fuel cost (M$)	46.7	57.5
CO2 released (MT)	2.9	0.4
CO2 captured (MT)	0.0	3.2

Retrofit year 5

Calendar year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2050**
Operation year	0	1	2	3	4	5	6	7	8	9	10	40
Investment costs (M$)												
Initial investment (M$)	$ (715.0)											
Retrofit Investment (M$)	$ -	$ -	$ -	$ -	$ (308.8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation (M$)	$ -	$ 209.3	$ 142.9	$ 97.6	$ 66.7	$ 135.9	$ 92.8	$ 63.4	$ 43.3	$ 29.6	$ 20.2	$ 0.0
Operating costs (M$)												
Fuel	$ -	$ (46.7)	$ (46.7)	$ (46.7)	$ (46.7)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (46.7)
O&M	$ -	$ (31.5)	$ (31.5)	$ (31.5)	$ (31.5)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (31.5)
Insurance and property tax	$ -	$ (12.7)	$ (12.7)	$ (12.7)	$ (12.7)	$ (18.2)	$ (18.2)	$ (18.2)	$ (18.2)	$ (18.2)	$ (18.2)	$ (18.2)
CO2 tax	$ -	$ -	$ -	$ -	$ -	$ (9.0)	$ (9.5)	$ (9.9)	$ (10.4)	$ (11.0)	$ (11.5)	$ (403.8)
CO2 transport and sequestration	$ -	$ -	$ -	$ -	$ -	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ -
Depreciation & O&M tax shield	$ -	$ 120.1	$ 93.6	$ 75.4	$ 63.1	$ 109.5	$ 92.4	$ 80.8	$ 73.0	$ 67.7	$ 64.2	$ 200.1
Cash Flow (M$)												
Total cash flow	$ (715.0)	$ 29.1	$ 2.6	$ (15.6)	$ (336.7)	$ (28.3)	$ (45.8)	$ (57.9)	$ (66.2)	$ (72.0)	$ (76.1)	$ (300.2)
Discount factor	1.00	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.10
Discounted cash flow	$ (715.0)	$ 27.5	$ 2.3	$ (13.1)	$ (266.7)	$ (21.1)	$ (32.3)	$ (38.5)	$ (41.5)	$ (42.6)	$ (42.5)	$ (29.2)
CO2 tax rate						$ 25.0	$ 26.3	$ 27.6	$ 28.9	$ 30.4	$ 31.9	$ 137.9

Lifetime NPV cost (M$)	**$ (1,888.02)**
Lifetime CO2 emissions (MT)	**24.7**
Lifetime CO2 sequestered (MT)	**116.8**

Case 3 **IGCC with Pre-Investment**

Economic parameters	
Discount rate	6.0%
Inflation	2.5%
Capacity factor	80%
Fuel cost	1.50
Net output (MWe)	500
Tax rate	40%
Depreciation (annual)	30%
Insurance and property tax rate	1.78%
CO_2 tax (\$/t CO_2, 2010)	25
CO_2 tax growth rate (%)	5%
CO_2 transp. & seq cost (\$/t CO_2)	$ 5.00

Scenario inputs	**Initial plant**	**Retrofit**
Investment (M$)	744.5	265.0
O&M cost (M$)	31.5	36.8
Fuel cost (M$)	46.7	57.5
CO_2 released (MT)	2.9	0.4
CO_2 captured (MT)	0.0	3.2

Retrofit year 5

Calendar year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2050**
Operation year	0	1	2	3	4	5	6	7	8	9	10	40
Investment costs (M$)												
Initial investment (M$)	$ (744.5)											
Retrofit Investment (M$)	$ -	$ -	$ -	$ -	$ (265.0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation (M$)	$ -	$ 217.9	$ 148.8	$ 101.6	$ 69.4	$ 125.0	$ 85.3	$ 58.3	$ 39.8	$ 27.2	$ 18.6	$ 0.0
Operating costs (M$)												
Fuel	$ -	$ (46.7)	$ (46.7)	$ (46.7)	$ (46.7)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (57.5)	$ (46.7)
O&M	$ -	$ (31.5)	$ (31.5)	$ (31.5)	$ (31.5)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (36.8)	$ (31.5)
Insurance and property tax	$ -	$ (13.3)	$ (13.3)	$ (13.3)	$ (13.3)	$ (18.0)	$ (18.0)	$ (18.0)	$ (18.0)	$ (18.0)	$ (18.0)	$ (18.0)
CO_2 tax	$ -	$ -	$ -	$ -	$ -	$ (9.0)	$ (9.5)	$ (9.9)	$ (10.4)	$ (11.0)	$ (11.5)	$ (403.8)
CO_2 transport and sequestration	$ -	$ -	$ -	$ -	$ -	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ (16.2)	$ -
Depreciation & O&M tax shield	$ -	$ 123.8	$ 96.1	$ 77.3	$ 64.4	$ 105.0	$ 89.3	$ 78.7	$ 71.5	$ 66.7	$ 63.4	$ 200.0
Cash Flow (M$)												
Total cash flow	$ (744.5)	$ 32.3	$ 4.6	$ (14.3)	$ (292.1)	$ (32.5)	$ (48.6)	$ (59.7)	$ (67.4)	$ (72.8)	$ (76.6)	$ (300.0)
Discount factor	1.00	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.10
Discounted cash flow	$ (744.5)	$ 30.4	$ 4.1	$ (12.0)	$ (231.4)	$ (24.3)	$ (34.3)	$ (39.7)	$ (42.3)	$ (43.1)	$ (42.8)	$ (29.2)
CO_2 tax rate						$ 25.0	$ 26.3	$ 27.6	$ 28.9	$ 30.4	$ 31.9	$ 137.9

Lifetime NPV cost (M$)	**$ (1,883.79)**
Lifetime CO_2 emissions (MT)	**24.7**
Lifetime CO_2 sequestered (MT)	**116.8**