Chapter 2
Coal and Coal/Biomass-Based Power Generation

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Abstract Coal is a key, growing component in power generation globally. It generates 50% of U.S. electricity, and criteria emissions from coal-based power generation are being reduced. However, CO_2 emissions management has become central to coal's future. To meet growing electricity demand, coal use is expected to increase in the foreseeable future because it is cheap and abundant. For this to happen CO_2 capture and geologic sequestration (CCS) is a critical technology. With CCS, coal-based power generation can be made much cleaner. Commercial demonstration of existing technologies, including CCS, with the resultant improvements that will accrue, is key to advancing coal-based power generation and addressing important environmental issues.

2.1 Introduction

Coal is used to generate 50% of U.S. electricity and about 40% of the electricity produced globally [1]. For China and India, the fraction of power that is based on coal is about 77% and 74% respectively [2], and it is growing. Because of its history, coal-based power generation in the absence of adequate controls can be a major emitter of air pollutants and thus is perceived as being dirty. CO_2 emissions from coal-based power generation have now also become a major concern. This chapter addresses both of these issues but focuses on CO_2 emissions and the implications to global climate change.

Total global CO_2 emissions from coal-based power generation totaled almost 7.5 billion tonnes in 2007; this is about 30% of the global fossil-related CO_2 emissions.

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Respectively, the U.S. and China emitted an estimated 5.9 and 6.7 billion tonnes of CO_2 from fossil fuel combustion and cement production, of which about 1.9 billion tonnes and 2.3 billion tonnes of CO_2 were from coal-based power generation in 2007 [3, 4]. Power plants are some of the largest single point source emitters; a typical 1,000 MW_e coal-fired power emits over 6 million tonnes of CO_2 per year. Examples of the annual CO_2 emissions for selected large power plants in several countries are given in Table 2.1 [5, 6].

Coal is a critical fuel for power generation because it is abundant and cheap – \$1–\$2 per million Btu, compared with \$4–\$12 per million Btu for natural gas and oil. Coal is also very abundant with estimated proven global reserves of about 900 billion tonnes which is equivalent to about 160 years at current production rates [7]. The three largest coal consumers – China, the U.S., and India – have about half the global reserves of coal and have limited reserves of other fossil fuels. The U.S., with about 250 billon tonnes of recoverable coal reserves, has 27% of the world total [1]. Global primary energy demand is projected to grow by just over 50% by 2030, and world electricity demand is projected to double by 2030. Given this situation, coal-based power could account for a significant portion of this growth, but that is not assured. This will require that growth continues and coal-based technologies improve significantly with respect to their environmental footprint. Figure 2.1 shows the increase

Table 2.1 CO_2 emissions from selected large coal-fired power plants

Plant name	Country	CO_2 emissions, million tonnes/year
Taichung	Taiwan	37.5
Poryong	South Korea	34.4
Tuoketuo	China	29.5
Vindhyachal	India	26.4
Hekinan	Japan	26.3
Janschwalde	Germany	24.9
Miller	USA, Alabama	18.7
Gibson	USA, Indiana	18.5
WA Parish	USA, Texas	18.3

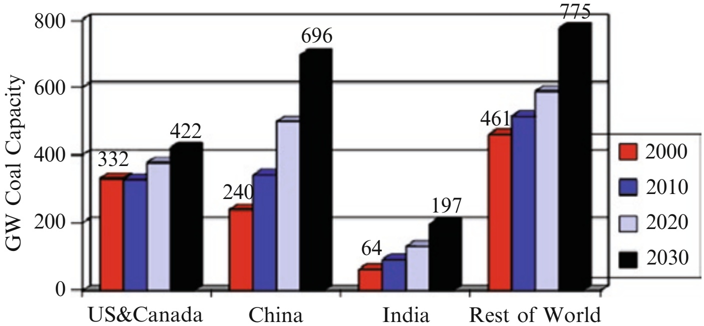

Fig. 2.1 Projected increase in coal-based power generation capacity by region to 2030 [1]

in coal generating capacity as projected by the IEA [1]. Internal Chinese projections for growth in coal-based power generation exceed IEA projections, reaching about 1,050 GW in 2030 and about 1,400 GW by 2050 [8]. Actual annual growth rate of coal-based power generation in China exceeded 20%/year from 2000 to 2007, and significant further growth is projected (Fig. 2.1). The criticality of reducing the environmental footprint of and controlling CO_2 emissions from coal-based power generation is obvious if these growth projections are to be realized. Further, most of this coal-based generation growth is in developing-world countries, which desperately need additional power generation to support economic growth, increase their standard of living, and reduce poverty.

This chapter focuses on the technologies for generating electricity from coal and on managing related emissions, particularly CO_2 emissions. It addresses the cost and performance of power generation from coal, of criteria emissions control, and of CO_2 capture and geologic sequestration (CCS) for different generating technologies. It is an update and expansion on a recent article by the author [9] and is based on a number of sources, particularly "The Future of Coal" [10], and recent comprehensive design work by Williams and co-workers at Princeton University, Princeton Environmental Institute [11]. Additional information is available in [12]. The impact of co-firing coal and biomass and of utilizing biomass alone on cost, performance, and CO_2 emissions associated with power generation is also considered. These considerations utilize the same cost and operational bases across all technologies, including those in Chap. 3, to make the comparisons as relevant as possible.

The overall approach used here involved picking a point set of design and operating conditions at which to compare technologies. The design bases for the comparisons include:

- Each unit was a Greenfield unit with 500 MW_e net generating capacity
- Each technology was designed to control criteria emissions to somewhat below today's best-demonstrated commercial performance.
- Costs were based on 2000–2006 detailed cost designs for the U.S. Gulf Coast; indexed to the mid-2007 construction cost environment as indicated by the Chemical Engineering Plant Cost Index. As indicated in Fig. 2.2, construction costs escalated rapidly from 2000, after a period of stability; mid-2007 CEPCI was a compromise level. Such rapid escalations as indicated by the HIS-CERA Index are likely not sustainable and could see self-correction when economic conditions change.
- Commercially demonstrated technologies were integrated, and cost estimates are for the Nth plant, where N is of order five to seven, for those technologies that are still evolving. This is meant to allow the learning's from the first couple of plants constructed to be engineered into future cycles of plants.
- Performance and costs are based on a single set of conditions for each technology and on the EPRI-recommended approach to calculate levelized cost of electricity (COE). Key economic and operating parameters are given in Table 2.2, and the properties of the feedstocks used, Illinois # 6, high-sulfur coal, and switch grass are given in Table 2.3.

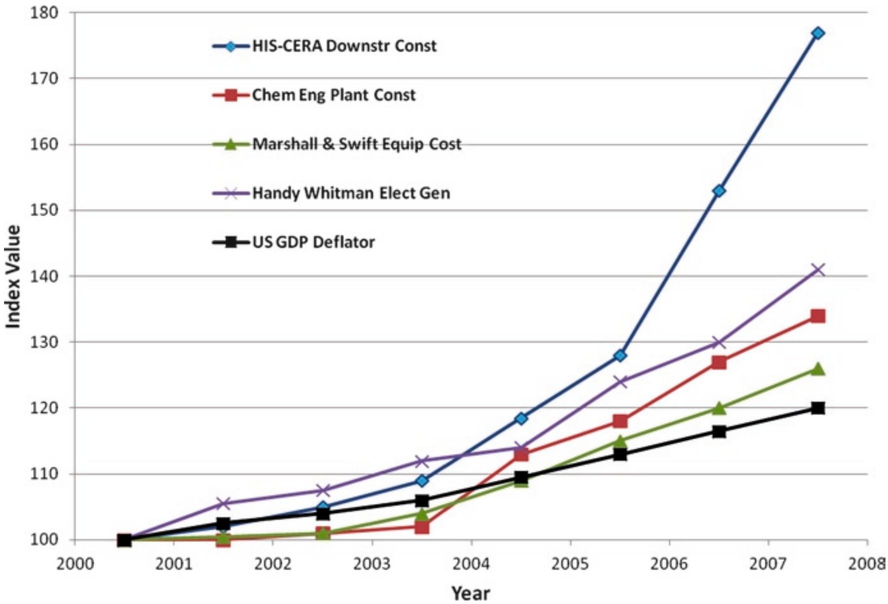

Fig. 2.2 Recent increases in construction cost as represented by several construction cost indices. Indices normalized to 100 in 2000 (Courtesy EPRI [13])

Table 2.2 Key economic and operating parameters used in developing cost comparisons [11]

Base year for capital costs, Gulf Coast	Mid-2007
Capital change rate, % of TPI per year	14.40
Interest during construction (3 year), % of TPC	7.16
O&M, % of TPC per year	4.00
Capacity factor of coal plans	85%

Table 2.3 Key parameters of feedstocks used in process analysis [11, 12]

Coal, Illinois #6, Herrin	
Coal price, $/GJ (HHV, as received)	1.71
Coal price, $/tonne, AR	46.4
HHV, MJ/kg (AR)	27.1
Wt% Carbon (AR)	63.7
Wt% Sulfur (AR)	2.51
Wt% Ash (AR)	9.7
Wt% Moisture (AR)	11.1
Biomass, Switchgrass	
Biomass price, $/GJ (HHV)	5
HHV, MJ/kg (AR)	15.9
Wt% Carbon (AR)	40
Wt% Sulfur (AR)	0.08
Wt% Ash (AR)	5.3
Wt% Moisture (AR)	15

This provides an indicative cost comparison from technology to technology. Obviously, coal type, plant site and location, dispatch strategy, and a myriad of design and operating parameter decisions will affect cost and operation but are not explored here [10]. The same comments apply to the estimates of Chap. 3 and will not be repeated there. In both chapters, production costs are presented by category so that the impact of capital cost, feedstock cost, etc., can be evaluated. The important issue is comparison among technologies, including without CO_2 capture and with CO_2 capture and geologic storage. Technology and costs for CO_2 transport and geologic storage are generation-technology independent, and costs are based on the CO_2 quantity stored.

2.2 Power Generating Technologies

2.2.1 Air-Blown Pulverized Coal (PC)

2.2.1.1 Without CO_2 Capture

A PC unit with a complete set of advanced criteria-emissions controls is shown in Fig. 2.3. It can be viewed as consisting of three blocks: the boiler block, the steam-cycle steam-turbine block, and the flue gas clean-up block as shown in Fig. 2.4. The design and operating conditions of the steam-cycle block largely determines the generating efficiency of the unit. For most existing PC units, the design and operating conditions of the steam cycle is below the critical point of water, which is referred to as subcritical operation. Operation above the critical point of water is referred to as supercritical operation. Ultra-supercritical is used to denote operation

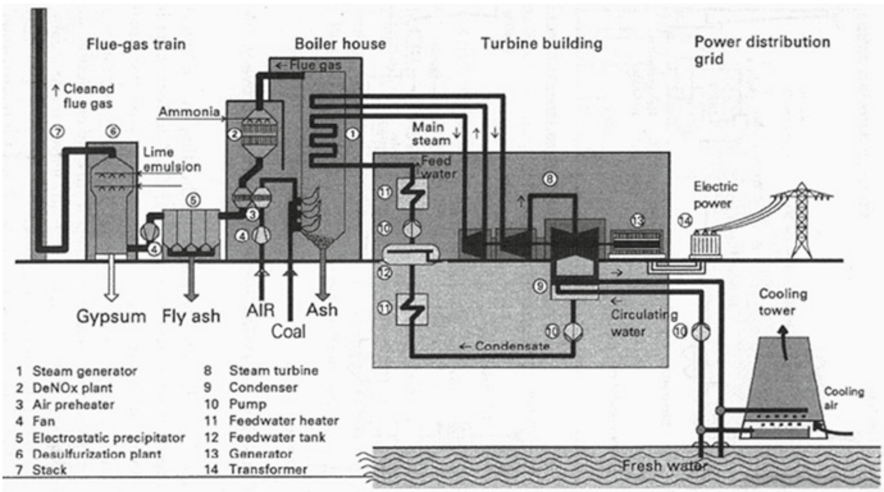

Fig. 2.3 Advanced pulverized coal unit (Courtesy ASME)

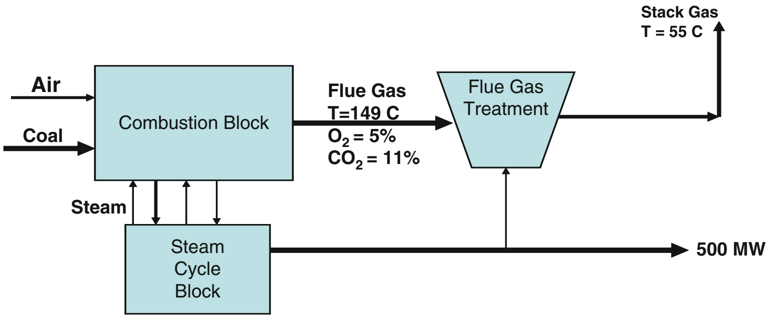

Fig. 2.4 Schematic of advanced pulverized coal unit

above a somewhat arbitrary set of operating parameters in the supercritical region. These ranges and typical generating efficiencies are summarized below.

For PC units, typical operating conditions and overall electrical generating efficiency are:

- Subcritical Unit
  - Steam-cycle operation to 550°C (1,025°F) and 2,400 psi
  - 33–37% overall generating efficiency (HHV)
- Supercritical Unit
  - Steam-cycle operation to 565°C (1,050°F) and 3,530 psi
  - 37–42% overall generating efficiency (HHV)
- Ultra-Supercritical Unit
  - Steam-cycle operation 600–620°C (1,110–1,150°F) and 4,650 psi
  - 42–45% overall generating efficiency (HHV)

Moving from subcritical to ultra-supercritical generating conditions reduces coal consumption by over 20% per kW_e-h of electricity generated. Moving from subcritical generating conditions to typical supercritical generating conditions can reduce coal consumption by over 10% per kW_e-h of electricity generated. Obviously, the higher the generating efficiency the lower the CO_2 emissions per kW_e-h of electricity generated. At a minimum, units need to be designed and operated at the highest efficiency that is economically justified to reduce CO_2 emissions. Current R&D programs are focusing on developing and proving materials and operating conditions above current ultra-supercritical conditions that could provide even higher PC generating efficiency. The next step in USCPC is 650°C (1,200°F) with generating efficiency exceeding 45%, with the next tranche being to 760°C (1,400°F) with efficiencies exceeding 48%. Materials properties, fabrication, and maintenance currently limit reaching these latter conditions.

The U.S. coal fleet consist largely subcritical generating units, with a limited number of supercritical units. Interest in supercritical technology in the U.S. has recently increased. India and China have built almost exclusively subcritical technology, but both countries have begun to construct a mix of sub and supercritical units. Meanwhile, Europe and Japan have built about a dozen ultra-supercritical units during the last decade [14]. Using modern materials technology, these units have reliability records equal to subcritical unit operation. The U.S. is behind in PC generating efficiency with a fleet average of about 33% [15].

2.2.1.2 With CO_2 Capture

A marked reduction of CO_2 emissions from PC power generation would require CO_2 capture from the flue gas, involving addition of another unit to the flue gas train. Today, the choice for CO_2 capture technology for PC generation would be amine absorption. Amine CO_2 capture is commercially proven in smaller-scale applications, including recovery of CO_2 from the flue gas of several smaller units for beverage, food and other industrial uses. The application of CO_2 capture from power plant flue gas is illustrated in Fig. 2.5. CO_2 is captured in the amine solution and then must be recovered from the solution. A large amount of energy is required to recover the CO_2 from the amine solution, regenerating the solution to capture more CO_2. A smaller amount of energy is needed to compress the CO_2 to a supercritical fluid. An energy diagram illustrating the parasitic energy requirements for CO_2 capture from a subcritical PC unit is shown in Fig. 2.6. For PC generating units that are designed for capture, the generating efficiency is reduced by about 9–11% points independent of steam cycle type. For subcritical, supercritical, and ultra-supercritical units estimated generating efficiency reductions are from 34% to 25%, from about 39% to 29%, and from 43% to 34% respectively for example. To maintain constant electrical output requires a 38–40% increase in coal consumption when a CO_2 capture designed unit is compared with a non-capture designed unit [10, 11, 13].

The energy comparison illustrated in Fig. 2.6 is for units that are designed specifically for capture or no-capture, and thus, all the components are of optimum

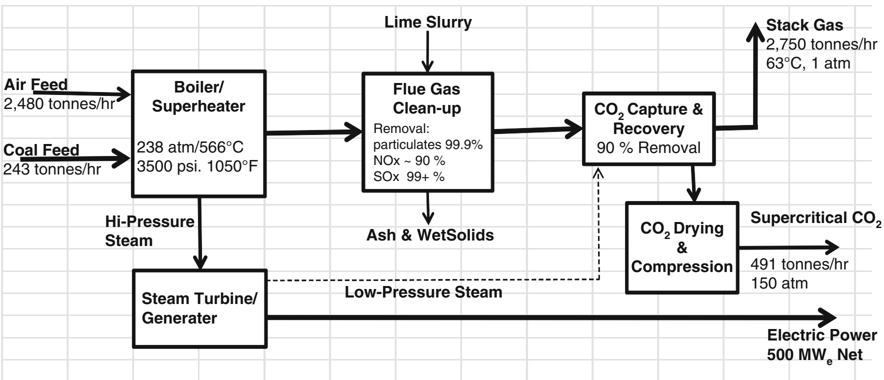

Fig. 2.5 Supercritical 500 MW_e pulverized coal unit with CO_2 capture: projected generating efficiency is 29.3% vs. 38.5% for generation without CO_2 capture

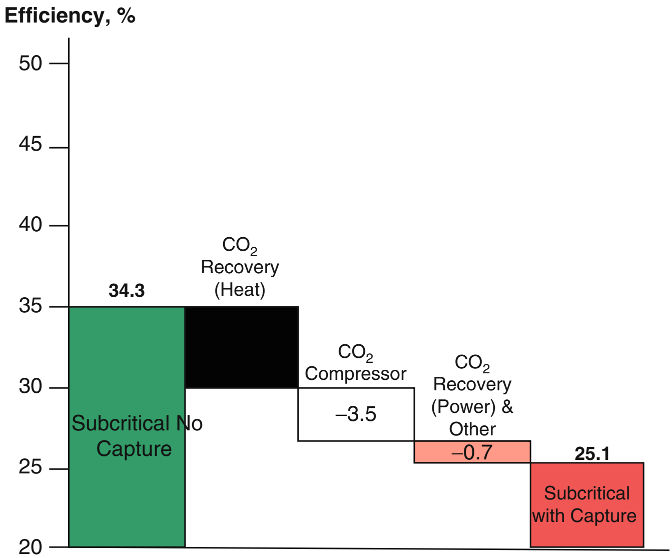

Fig. 2.6 Parasitic energy consumption associated with a subcritical PC unit with post-combustion CO_2 capture versus a subcritical PC unit without CO_2 capture [10]

size and performance to provide the maximum total unit efficiency. If a unit designed for no-capture is retrofitted for capture at a later date, the efficiency penalty for CO_2 capture is larger because some of the components become sub-optimum. This will be addressed further in the discussion of retrofitting.

Other approaches to CO_2 capture are being examined. For example, the use of chilled ammonia absorption is claimed to significantly reduce these energy requirements and is being evaluated on a 1.7 MW_e system at a 1,224 MW_e commercial coal-fired generating station in Wisconsin [16, 17]. Additional approaches being pursued include unique framework solids, algal systems, frosting, and other adsorbents. These are further from economic evaluation or demonstration. Improvements can be expected for absorption and adsorption systems, but there are physiochemical and thermodynamic limitations to how large these improvements will be.

2.2.2 *Oxygen-Blown Power Generation*

The main problem with CO_2 capture from air-blown units is the low CO_2 concentration in the flue gas due to nitrogen dilution. This can be solved by substituting oxygen for air. For PC combustion, this is Oxy-Fuel PC combustion. Another approach is to gasify the coal with oxygen and steam, and remove the CO_2 at high pressure prior to combustion of the syngas in a gas turbine. This approach is Integrated Gasification Combined Cycle (IGCC) power generation.

2.2.2.1 Oxy-Fuel PC Combustion

Oxy-fuel combustion, shown schematically in Fig. 2.7, addresses the high CO_2 capture and recovery costs, but it does so at the expense of an air-separation unit and its associated energy costs [18, 19]. The advantage is gained through being able to cool the flue gas, condensing out water, and leaving almost pure CO_2 which can then be compressed, with further drying, to produce supercritical CO_2 for geologic storage. A parasitic energy diagram for oxy-fuel is shown in Fig. 2.8.

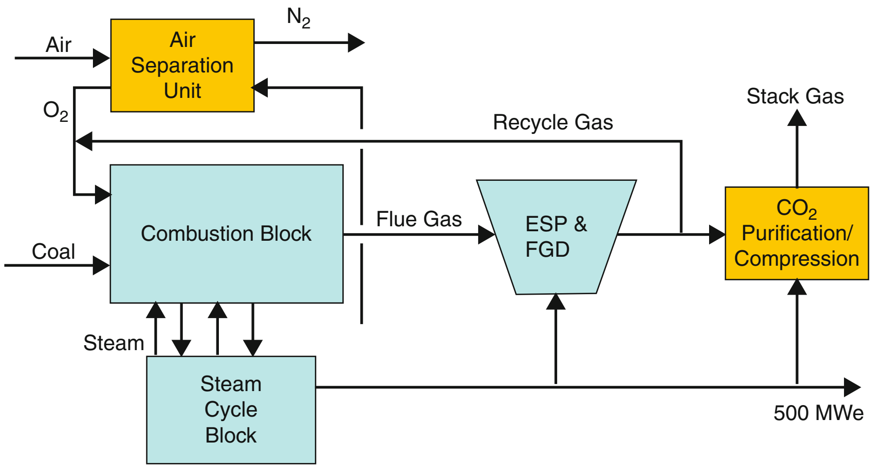

Fig. 2.7 Schematic of a pulverized coal oxy-fuel generating unit with CO_2 capture achieved by drying and compression. The volume of gas that goes up the stack is projected to be small

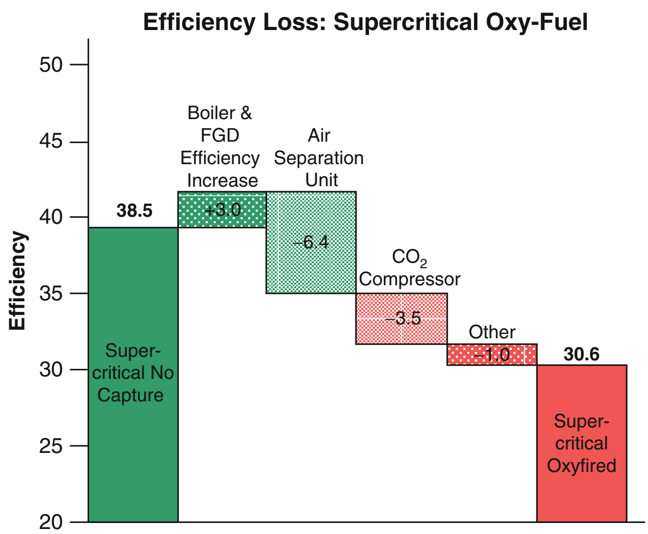

Fig. 2.8 Parasitic energy consumption associated with oxy-fuel combustion versus supercritical PC generation without CO_2 capture [10]

Boiler efficiency is improved somewhat, but this gain is more than offset by the power requirements of the oxygen separation unit.

The technology is in active pilot plant development, and the early stages of commercial demonstration. A 30 MW_{th} oxy-fuel pilot plant was commissioned in Schwarze Pumpe, Germany in mid-2008, with plans for a 300 MW demonstration plant followed by a 1,000 MW commercial plant [20, 21]. Because of the early state of commercial development, the performance and cost estimates are not as firm as those for PC or IGCC. Oxy-fuel PC has the potential for lower cost of electricity (COE) and lower CO_2 avoided cost than with PC capture. The development of this technology should be monitored.

2.2.3 IGCC

2.2.3.1 Without CO_2 Capture

IGCC power generation from coal is illustrated in Fig. 2.9, showing the main process components and stream flows. Oxygen from an air separation unit is used to combust sufficient carbon in the gasifier typically at 500–1,000 psig to increase the temperature to around 1,500°C (2,730°F). For typical coals, the ash melting point is between 1,200°C and 1,450°C. At 1,500°C, the coal ash melts and leaves the bottom of the gasifier as slag. At this temperature, water (steam), which is added with the coal or separately, reacts with the remaining carbon to convert it to

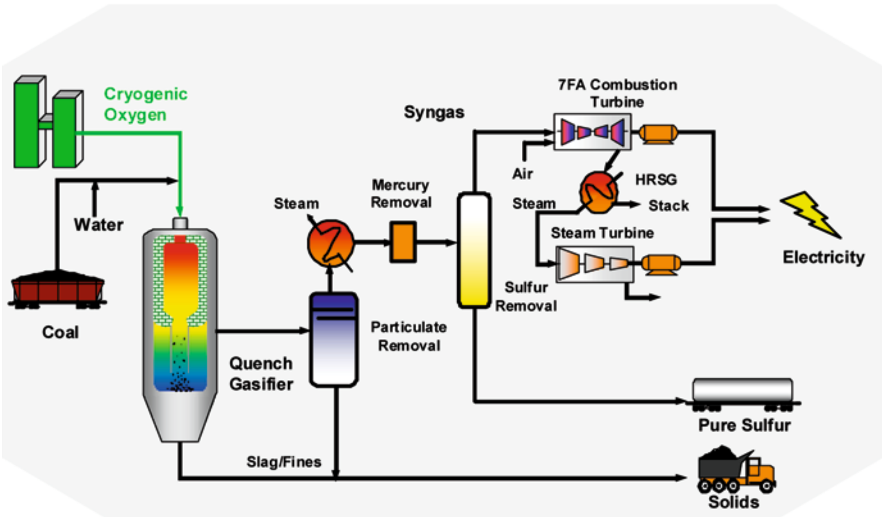

Fig. 2.9 A representative coal-based IGCC unit showing main process components and streams (Courtesy NETL)

syngas, a mixture mainly of carbon monoxide (CO) and hydrogen (H_2) and some CO_2, along with impurities such as H_2S, NH_3 & mercury. The syngas is quenched with water to remove particulate matter, cleaned of impurities, and then burned in a turbine in a combined-cycle power block that is very much like a natural gas combined-cycle (NGCC) unit (see Fig. 2.9). Because all the gases are contained at high pressure, high levels of particulate matter, sulfur, mercury, and other pollutant removal are possible. Air emissions levels from an IGCC unit should be similar to those from a NGCC unit. Coal mineral matter is removed from the gasifier as a solid, relatively dense vitreous slag.

The gasifier is the biggest variable in the system in terms of type (moving bed, fluid bed, and entrained flow), feed approach (water-slurry, dry feed), operating pressure, and the amount of heat removed from it. For IGCC units to date, entrained-flow gasifiers have been the primary choice. For electricity generation, without CO_2 capture, radiant and convective cooling sections behind the gasifier that produce high-pressure steam for additional power generation lead to efficiencies that can approach or exceed 40%. The additional heat removal options are illustrated in Fig. 2.10.

Figure 2.11 is a schematic of a 500 MW_e IGCC unit summarizing the operating conditions and giving the stream flows for no CO_2 capture. The unit is using Illinois #6 coal at rate of 185,000 kg/h or 4,400 tonnes of coal per day. This unit, which employs radiant cooling but not convective cooling, has a generating efficiency of 38% on an HHV basis [10, 13].

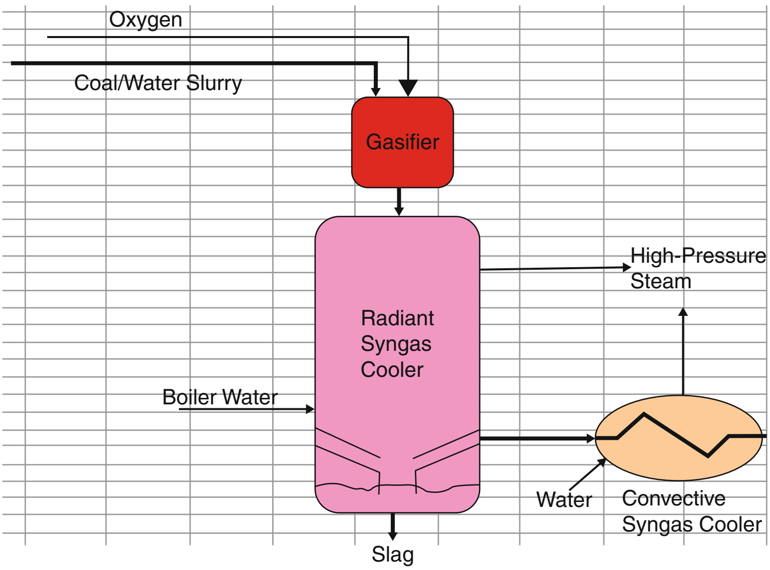

Fig. 2.10 Heat recovery options for an entrained-flow gasifier. Additional steam produced is used to generate electricity

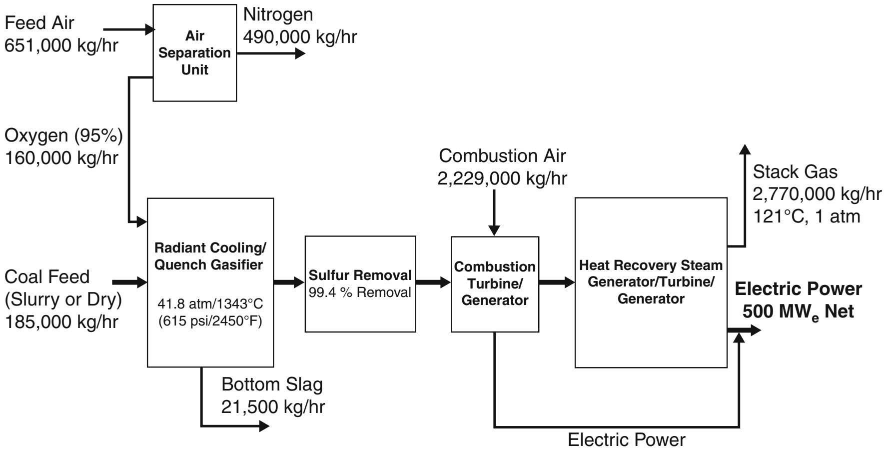

Fig. 2.11 Schematic of 500 MW$_e$ IGCC unit without CO_2 capture. Projected generating efficiency with radiant cooling is 38.4% [10]

2.2.3.2 With CO_2 Capture

A block diagram with key material flows for a 500 MW$_e$ IGCC unit designed for CO_2 capture is shown in Fig. 2.12. To achieve CO_2 capture with IGCC, the CO in the syngas must first be converted to CO_2 and H_2 via the water gas shift reaction ($CO + H_2O \rightarrow CO_2 + H_2$). To do this, two catalytic shift reactors are added just behind the quench to convert H_2O and CO to H_2 and CO_2. The gas clean-up train requires addition of a second gas-scrubbing unit located behind the sulfur-scrubbing unit to remove the CO_2. The CO_2 capture and recovery is done at high concentration and pressure, involves weak absorption, and recovery of the CO_2 is by pressure letdown. As such, it requires less energy and is cheaper than for dilute CO_2 capture from flue gas. The estimated generating efficiency for the design and operating parameters is 31–32% [10, 13]. Figure 2.13 illustrates the parasitic energy requirements to capture the CO_2 in an IGCC plant; the efficiency loss is about 7 percentage points vs. about 10–11% points for PC with CO_2 capture. The largest efficiency reduction is related to generating the steam required for the water gas shift reaction. CO_2 compression is second largest but is less than for PC because the compression begins at a higher pressure. After shift and clean up, the resulting gas stream is largely H_2, which is then burned in a combustion turbine as part of a combined cycle unit to generate power. Turbines that can burn high concentrations of H_2 have not yet been developed. All other technologies are commercial. For example, ammonia production from coal utilizes all the steps up to combustion and is practiced in the US, Europe, and particularly China. However, these technologies have yet to be integrated and

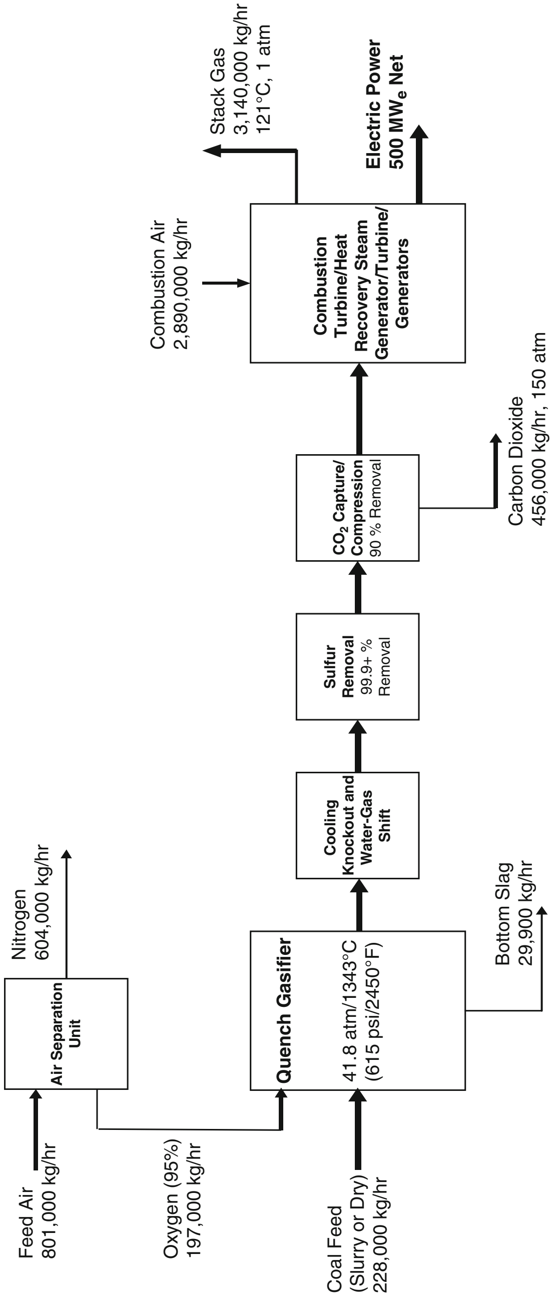

Fig. 2.12 500 MW_e IGCC with CO_2 capture. Projected generating efficiency with quench gasifier is 31.2% [10]

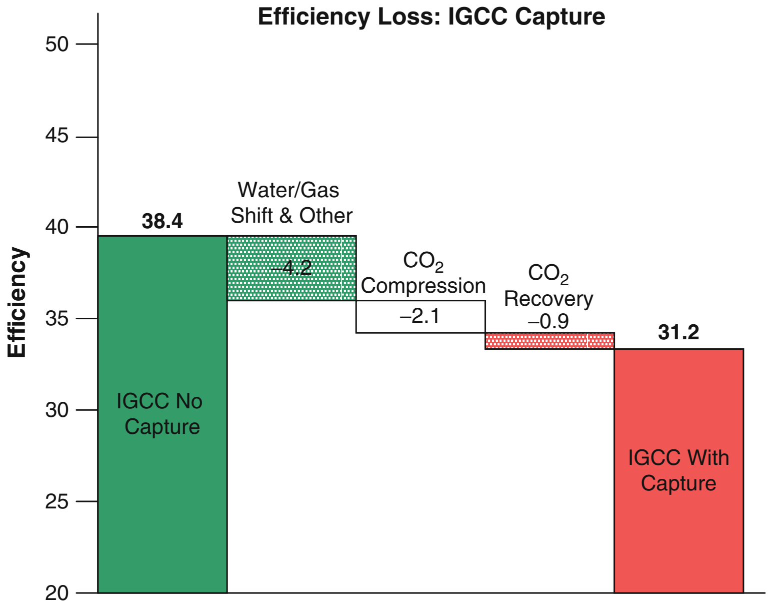

Fig. 2.13 Typical parasitic energy consumption associated with IGCC for pre-combustion CO_2 capture vs. IGCC designed for no CO_2 Capture [10]

demonstrated at the scale of operation required for large-scale power generation. Turbines that can burn very high H_2 concentrations are under development, but current turbines can only burn H_2 with appropriate dilution with N_2 from the air separation plant. Turbines designed for hydrogen combustion could provide an additional increase in generating efficiency.

2.3 Performance and Cost Summary

2.3.1 Cost

Table 2.4 summarizes the operating and cost parameters associated with the generating technologies discussed above. This indicative cost and performance data allow comparison among the generating technologies for mid-2007 Gulf-Coast construction costs.

Without CO_2 capture, PC has the lowest COE; the COE for IGCC is 10–15% higher. However with CO_2 capture, IGCC has the lowest COE. The cost of capture and compression for supercritical PC is about 4.8¢/kW$_e$-h; that for IGCC is about one half that or about 2.4¢/kW$_e$-h. The cost of transport and storage was estimated

Table 2.4 Performance and costs for coal-based power generating technologies [9–11]

	Subcritical PC		Supercritical PC		PC- Oxy	IGCC	
	w/o capture	w/ capture	w/o capture	w/ capture	w/ capture	w/o capture	w/ capture
PERFORMANCE							
Heat rate[a], Btu/kW_e-h	9,950	13,600	8,710	12,600	11,200	8,910	10,500
Generating efficiency (HHV)	34.3%	25.1%	39.2%	27.2%	30.6%	38.3%	32.5%
CO_2 emitted, kg/h	453,000	61,900	396,000	57,100	25,400	400,000	45,600
CO_2 captured at 90%, kg/h[b]	0	557,000	0	514,000	482,000	0	422,000
CO_2 emitted, g/kW_e-h	905	124	792	114	51	794	91
Life-cycle CO_2 emitted, g/kW_e-h			831	170		833	138
COSTS							
Total plant cost, \$/kW_e	1,564	3,085	1,625	2,961	2,450	1,977	2,644
Cap. Ch ar.,¢/kW_e-h @ 14.4%[c]	3.24	6.38	3.36	6.13	5.07	3.90	5.10
Fuel, ¢/kW_e-h @ \$1.50/MMBtu	1.80	2.45	1.57	2.26	2.01	1.63	1.89
O&M, ¢/kW_e-h	0.84	1.66	0.87	1.59	1.32	1.06	1.33
COE, ¢/kW_e-h	**5.87**	**10.50**	**5.81**	**9.98**	**8.40**	**6.60**	**8.32**
CO_2 Disposal Cost, ¢/kW_e-h	0.00	0.72	0.00	0.67	0.63	0.00	0.57
COE[d], ¢/kW_e-h	**5.87**	**11.22**	**5.81**	**10.65**	**9.03**	**6.60**	**8.89**
Cost of CO_2 avoided vs. same technology w/o capture[d], \$/tonne		**\$68**		**\$71**	**\$43**		**\$37**

Basis: 500 MW_e plant net output. Illinois #6 coal (63.7%wt C, 27.1 MJ/kg (HHV), 85% cap Fac)

[a]Efficiency=3,414 Btu/kW_e-h/ (Heat rate)

[b]90% removal used for all capture cases, except PC-Oxy which was assumed 95%

[c]Annual capital charge rate of 14.4% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge

[d]Includes the cost of CO_2 transport and geologic storage, details discussed in the text

to be $6.5 per tonne of CO_2; the cost of transport and storage will be discussed later. The cost of CO_{2eq}-avoided for supercritical PC, including transport and geologic storage, is about $71 per tonne of CO_{2eq}; that for IGCC is about $37 per tonne. That for Oxy-fuel is estimated at $43 per tonne of CO_{2eq}. These numbers include the cost of CO_2 capture and compression to a supercritical fluid, and CO_2 transport and injection. Its lower COE would appear to make IGCC the technology of choice for CO_2 management in power generation. However, Oxy-fuel has significant potential, and current research and demonstration activities will provide needed cost and engineering information. Further, for a lower rank coal and a higher plant elevation, the cost difference between IGCC and PC narrows. As such, significant reductions in the capture/recovery cost for PC could make it economically competitive with IGCC with capture in certain applications. In addition, the power industry still has concerns about IGCC operability and availability. Thus, we cannot declare any of these technologies superior to the others at this point.

2.3.2 Cleaning-up Coal

Coal has the reputation of being dirty, largely based on criteria air emissions. Table 2.5 gives the commercially demonstrated and projected emissions performance of PC and IGCC technologies [14, 22]. Electrostatic precipitators (ESP) or bag houses are employed on all U.S. PC units, and particulate matter (PM) emissions are typically low. Improved ESP or wet ESP can reduce PM emissions further, but at a cost. Flue gas desulfurization (FGD) is applied on about one-third of U.S. PC capacity, and thus "typical (average) U.S." SO_x emissions (Table 2.5) are quite high. "Best commercial" performance in Table 2.5 gives demonstrated, full commercial-scale levels of emissions reductions [14, 22, 23]. Additional reductions are possible. With CO_2 capture, SO_x emissions levels are expected to be even further reduced [24]. The best commercial emissions performance levels with IGCC is threefold to tenfold lower (Table 2.5). IGCC with CO_2 capture should have even lower emissions. In addition, IGCC produces a dense, vitreous slag that ties up most of the toxic components in the coal mineral matter so that they are not easily leached [25],

Table 2.5 Commercially demonstrated and projected emissions performance with CO_2 capture for PC and IGCC power generation [9, 10]

Technology	Case	Particulates Lb/MM Btu	SO_2 Lb/MM Btu	NO_x Lb/MM Btu	Mercury % removed
PC plant					
	Typical	0.02	0.22	0.11	
	Best commercial	0.015 (99.5%)	0.04 (99+%)	0.03 (90+%)	90
	Design w CO_2 cap.	0.01 (99.5+%)	0.0006 (99.99%)	0.03 (95+%)	75–85
IGCC plant					
	Best commercial	0.001	0.015 (99.8%)	0.01	95
	Design w CO_2 cap.	0.001	0.005 (99.9%)	0.01	>95

Table 2.6 Incremental cost of advanced PC generation emissions control vs. no emissions control [9]

	Capital cost[a] [$/kW$_e$]	O&M [¢/kW$_e$-h]	COE[b] [¢/kW$_e$-h]
PM control	55	0.20	**0.31**
NO_x	40	0.15	**0.23**
SO_2	200	0.30	**0.71**
Incremental cost vs. no control	295	0.65	**1.25**[c]

[a] Incremental capital costs are for a new-build plant

[b] Incremental COE impact for Illinois #6 coal with 99.5% PM reduction, 99.4% SO_x reduction, and >90% NO_x reduction

[c] When this is added to the "no-control" COE for SC PC, the total COE is 5.8¢/kW$_e$-h

and IGCC uses about 30% less water than supercritical PC. Although this discussion does not address the whole life-cycle for coal's environmental footprint, coal-use in the electricity generation step can, in fact, be very much cleaner than it is today, and CO_2 emissions can also be markedly reduced.

The estimated cost to achieve the emissions reductions used in the PC design basis, which is somewhat better than today's best demonstrated commercial performance vs. no emissions control is about 1.25¢/kW$_e$-h (see Table 2.6) out of about 5.8¢/kW$_e$-h total COE or about 20% [26–29]. CO_2 capture and recovery will increase the COE more than this, about 4¢/kW$_e$-h, based on today's PC technology. Cost reductions can be expected when this technology begins to be commercially practiced.

2.3.3 Biomass, and Coal Plus Biomass to Power

Burning fossil fuels for power generation and for transportation releases carbon that has been stored for millions of years as CO_2 into the atmosphere, resulting in the build-up of atmospheric CO_2. Using biomass as a fuel releases carbon removed as CO_2 from the atmosphere in a recent plant growth cycle and does not contribute to increasing atmospheric CO_2 concentration if done sustainably. Thus, using biomass in power generation reduces the life-cycle emissions of CO_2 per unit of power generated.

Biomass can be burned directly or co-fired with coal in a boiler. The major issues are effective size reduction of the biomass in order to feed it into the boiler and its lower energy density. Today, most biomass power plants burn demolition wood wastes, forest product wastes or agricultural wastes to produce steam for power generation. The U.S. has 11 GW of installed biomass-only plant capacity [30], with an average size of 20 MW$_e$. The industry average generating efficiency is of order 20%. Typically SO_x emissions are low because biomass contains little sulfur, but NO_x emissions can be quite high because the relatively high nitrogen content of many biofuels. These emissions can be controlled, at a cost, which, however, can be significant on small units. A generally more attractive approach is to co-fire biomass at levels of less than 25% (wt.%) with coal to gain the advantages of scale of a much larger generating facility and reduced CO_2 emissions per kW_e-h generated. The other option is to gasify the biomass and generate power in a combined-cycled configured power island. Gasification technology is considered below, and the economic and CO_2 impacts of using biomass to generate power are discussed.

2.3.3.1 Thermochemical Conversion of Biomass

Biomass gasification and/or pyrolysis involves the conversion of biomass to a mixture of carbon monoxide, hydrogen, carbon dioxide, methane, and other organics including bio-oils and tars, ash and small char particles. The concentration of these gases and other materials depends on the process design, and operating conditions. Gasification has the advantage that it can convert essentially any biomass material to syngas at sufficiently severe conditions (Fig. 2.14). This syngas can be burned in a boiler or can be cleaned and burned in a turbine in a combined cycle power island to produce electricity. It could also be cleaned and shifted to produce a synthesis gas from which a broad range of fuel and chemical products can be produced. This latter option is considered in Chap. 3. Biomass gasification exhibits many similarities to coal gasification, including a significant number of gasifier types and different approaches to gasification technology. Electricity or fuels produced via gasification of biomass should have low net CO_2 emissions; and if biomass gasification is combined with capture and geologic storage of CO_2, such processes have a negative CO_2 emission footprint.

Gasification can be carried out under a variety of pressure and temperature conditions. When relatively low pressures and temperatures are used, it is primarily a pyrolysis process. Under these less-severe conditions, the main products are a mixture of hydrogen, CO, and light hydrocarbons, bio-oil, tars, and char. For less-severe gasification (pyrolysis), the heating is usually indirect, avoiding the need for an expensive air separation unit, reducing the capital cost significantly. The mix of

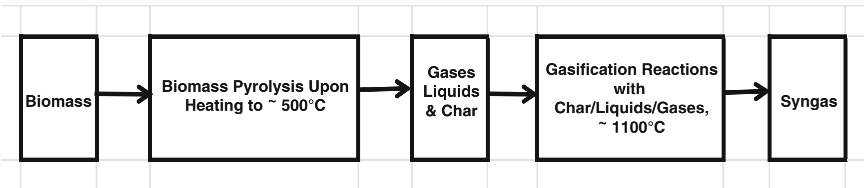

Fig. 2.14 Schematic of thermochemical conversion of biomass, flow from left to right. Pyrolysis produces a broad range of materials, including bio-oils and tars, which can undergoes gasification at higher temperatures to produce syngas, which is composed primarily of CO, H_2, and CO_2. One-step gasification at high temperature combines the pyrolysis and gasification stages to rapidly produce only syngas

primary products can be separated into several fractions for upgrading of for gasification or combustion. The gas stream can also be cleaned, compressed, the CO shifted to H_2 and CO_2, and the CO_2 removed for geologic storage.[1] If air is used directly as an oxidant in gasification, the nitrogen present results in a low Btu gas that is most easily used for steam or power generation via a boiler or combustion turbine but without CCS.

Biomass gasification using direct firing with oxygen at higher pressure and temperature produces a relatively pure syngas stream of CO and H_2, with some CO_2 and other gases. For temperatures greater than 1,100°C, little or no methane, higher hydrocarbons, or tar are present. The high oxygen content of biomass reduces the oxygen requirement and thus the air separation unit size and cost. With biomass there is almost no sulfur, limited ash, or few other contaminants to deal with, although there are issues with some feedstocks such as rice straw that contain silicon.

Several U.S. and European organizations are developing advanced biomass gasification technologies, and there are about ten different biomass gasifiers with a capacity greater than 100 tonnes per day operating in the U.S., Europe, and Japan. These units demonstrate a broad range of feedstocks, of feed capabilities, of gasifier characteristics, of product gas clean-up approaches, and of primary products. Biomass Technology Group (BTG) lists over 90 installations (most are small) and over 60 manufacturers of gasification technologies [31]. A recent NETL benchmarking report summarizes the status of larger scale biomass gasifiers [32] For example, at the McNeil Generating Station in Vermont, a low-pressure wood gasifier, which started operation in August 2000, converted 200 tonnes per day of wood chips into fuel gas for electricity generation [33].

Most of the gasification technologies have technical or operational challenges associated with them, but most of these issues are probably resolvable or manageable with commercial experience. Gasifier choice depends on the type of biomass feed and on the specific application of the gasification/pyrolysis products. The most persistent problem area appears to be biomass feed processing and handling, particularly if a gasifier must contend with different biomass feeds. DOE has funded five different advanced biomass R&D projects to advance the technology [33]. Although several of the available gasification technologies have been commercially demonstrated, biomass gasification technology has yet to be robustly demonstrated for commercial, integrated biomass gasification and power generation. The implication is that biomass gasification technology is still on a relatively steep learning curve, as is the integration of biomass gasification, gas clean up, and power generation or biofuel synthesis. A major characteristic of biomass gasification is that it will involve smaller units than coal gasification, and it will thus not benefit from the economies of scale of coal gasification. This is because of the dispersed nature

[1] Geologic storage of CO_2 (deep saline aquifer, depleted oil and gas reservoirs, and enhanced oil recovery) is considered most likely; other options such as deep ocean storage are considered unlikely.

of biomass and cost of biomass transport, which limit the area that could supply feedstock to a given plant to a relatively small radius near the plant site. This limits annual biomass feed availability to a given plant. This will increase the cost per unit product unless major process simplification and capital cost reductions can be achieved. A primary strategy has been to eliminate the air separation unit, which is typically required with most high-severity gasification technologies. This leads to gasification with air and involves nitrogen-diluted syngas or involves indirect heating to avoid nitrogen dilution which then typically produces a product stream containing more bio-oil, tar, and light hydrocarbon gases.

2.3.3.2 Power Generation

Next, the cost and performance, including CO_2 impacts, of biomass to power are examined. Because of the small scale of biomass-to-power plants and the higher cost of biomass vs. coal, biomass-combustion based power generation is generally not competitive with PC generation. However, with Renewable Energy Credits that are in effect in some locations, the technology can be profitable [34]. These cost issues can be reduced by co-firing with coal at a coal plant. In this case, there is additional expense associated with the higher cost of biomass vs. coal and with the facilities needed for biomass receiving, storage, preparation, and feeding into the boiler. These are in addition to the coal handling facilities. The rest of the PC unit remains essential the same. CO_2 emissions reductions are in direct proportion to the ratio of carbon per unit of biomass energy feed to the plant to the carbon per unit of coal energy feed.

The other approach to power generation involves gasification of biomass plus combined-cycle power generation. Using the approach outlined earlier for evaluating coal power plants, and utilizing a steam/oxygen blown fluidized-bed gasifier with gas cooling and gas cleaning for the biomass feed, a consistent set of cost and performance estimates were made [11, 35]. Table 2.7 summarizes these projections for biomass to power. It was assumed that the plants were sited such that 1 million tonnes of dry biomass per year is available for the plant (3,790 tonnes/day, 85% capacity factor).

Subcritical generation is assumed for conventional combustion, steam generation; CCS was not considered because of the high cost of flue gas CO_2 capture. Capital cost is higher primarily due to smaller unit size, and biomass fuel cost is more than twice that of coal. The resulting COE at 10¢/kW_e-h is about 70% higher than for a larger PC plant (5.8¢/kW_e-h) (Table 2.7 and Table 2.4). Although plant CO_2 emissions are similar to those of a coal-based plant, life-cycle CO_2 emissions are very small because the CO_2 was recently captured and will be recaptured in the next growth cycle. The small positive value (50 g CO_{2eq}/kW_e-h) is due to fossil-based emissions occurring in biomass production and transport.

Gasification-based generation [11] has higher efficiency with biomass, driven by lower utility costs for air separation and gas clean-up due to the high biomass oxygen content and low impurity levels. Estimated COE for biomass IGCC is about

Table 2.7 Projected cost and performance of power generation from biomass, and from coal plus biomass

	Biomass subcritical	Biomass IGCC		Coal/biomass IGCC	
	w/o capture	w/o capture	w/ capture	w/o capture	w/ capture
Performance					
Heat rate[a], Btu/kW$_e$-h	9,750	8,010	9,430	8,870	11,100
Generating efficiency (HHV), %	35.0	42.6	36.2	38.5	30.7
Coal feed, tonnes/day (AR)	0	0	0	3,480	3,480
Biomass feed, tonnes/day (AR)					
Carbon in feed, kg/h	63,100	63,100	63,100	155,000	155,000
CO_2 emitted, kg/h	229,000	209,000	29,200	530,000	12,800
CO_2 captured, kg/h[b]	0	0	179,000	0	132,000
Plant CO_2 emitted, g/kW$_e$-h	935	700	115	769	85
Life-Cycle CO_2 emitted, g/kW$_e$-h	50	−26	−740	478	−278
Costs					
Total plant cost, \$/kW$_e$	1,910	1,768	2,529	1,920	2,620
Total capital required, \$/kW$_e$	2,139	2,033	2,908	2,057	2,808
Inv. charge, ¢/kW$_e$-h @ 14.4%[c]	3.95	3.66	5.23	3.97	5.42
Fuel, ¢/kW$_e$-h	5.15	4.23	4.98	2.80	3.50
O&M, ¢/kW$_e$-h	1.03	0.95	1.36	1.03	1.40
COE, ¢/kW$_e$-h	**10.12**	**8.84**	**11.57**	**7.81**	**10.32**
CO_2 Disposal cost, ¢/kW$_e$-h	0.00	0.00	0.66	0.00	0.58
COE[d], ¢/kW$_e$-h total	**10.12**	**8.84**	**12.23**	**7.81**	**10.90**
Cost of CO_2 avoided vs. same technology w/o capture[d], \$/tonne			**47.6**		**41.5**

Basis: 500 MW$_e$ plant net output. Illinois #6 coal (63.7%wt C, 27.1 MJ/kg (HHV), 85% cap Fac)

[a]Efficiency = 3,414 Btu/kW$_e$-h/ (heat rate)

[b]90% removal used for all capture cases, except PC-Oxy which was assumed 95%

[c]Annual capital charge rate of 14.4% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge

[d]Includes the cost of CO_2 transport and geologic storage, details discussed in the text

50% higher than for PC generation and about 30% higher than coal IGCC, primarily because of the higher cost of biomass. Because biomass is the only feed, the electricity generated is essentially CO_2 neutral, because the CO_2 emitted from the plant was recently removed from the atmosphere and will be recaptured in the next growth cycle. However, it actually has a negative life-cycle CO_2 balance of minus 26 g CO_{2eq}/kW_e-h (without CCS) because the char from the gasification contains more carbon than fossil carbon consumed in the production and transportation of the biomass. This carbon is assumed permanently sequestered with the char. The COE for biomass IGCC is less than coal IGCC with CCS which still has a life-cycle CO_2 balance of +138 g CO_{2eq} /kW_e-h.

At zero life-cycle GHG (CO_{2eq}) price, biomass gasification with CCS has a COE that is about 25% higher than coal IGCC with CCS, but it has a large negative life-cycle CO_2 balance (−740 g CO_{2eq}/kW_e-h) associated with it. Therefore, it would receive a large CO_{2eq} credit in any carbon tax or carbon-trading regime. The cost of CO_{2eq} avoided is $48/tonne (Table 2.7). If coal-based PC with CCS is compared with biomass IGCC venting the CO_2 the avoided cost of CO_{2eq} is about $14/tonne. Comparing coal-based IGCC with CCS with biomass IGCC with venting, the cost of avoided CO_{2eq} is effectively zero (slightly negative) as is coal-based IGCC with CCS compared with biomass IGCC with CCS (slightly positive $/tonne CO_{2eq} avoided). These numbers should be considered to be zero within the ability to estimate costs at this point.

Co-feeding coal and biomass can provide improved generating economies-of-scale and reduced CO_2 emissions. To accommodate the different properties of biomass and coal, the process design estimates here are based on biomass gasification utilizing a steam/oxygen blown fluidized-bed gasifier and coal gasification via an entrained flow GE Texaco gasifier. Coal to biomass feeds were 60%/40% on an energy basis; 3,480 tonnes/day coal and 3,790 tonnes/day biomass, each on an as-received (AR) basis (Table 2.7) [11, 35]. The quenched syngas streams were combined to take advantage of available economies of scale downstream of gasification. With this configuration, without CCS, the COE for the coal/biomass case is about 20% higher (1.2¢/kW_e-h) than for the coal only case due mainly to the higher biomass fuel cost. Although the plant CO_2 emissions are similar, the life-cycle CO_2 emissions are 478 g CO_{2eq}/kW_e-h or about 40% less due to the 40% biomass feed, without CCS. With CCS, the COE is also about 20% higher (~2.0¢/kW_e-h) for the coal/biomass case than for the coal-only IGCC case. However, the life-cycle CO_{2eq} emissions are −278 g CO_{2eq}/kW_e-h for the coal plus biomass case vs. +138 g CO_{2eq}/kW_eh for the coal-only IGCC with CCS.

2.3.4 CCS Carbon Chain

The carbon chain from fossil fuel or biomass from its source through the process to carbon capture and sequestration (CCS) is shown in Fig. 2.15. We have already considered the first two steps (boxes) in the figure for power generation.

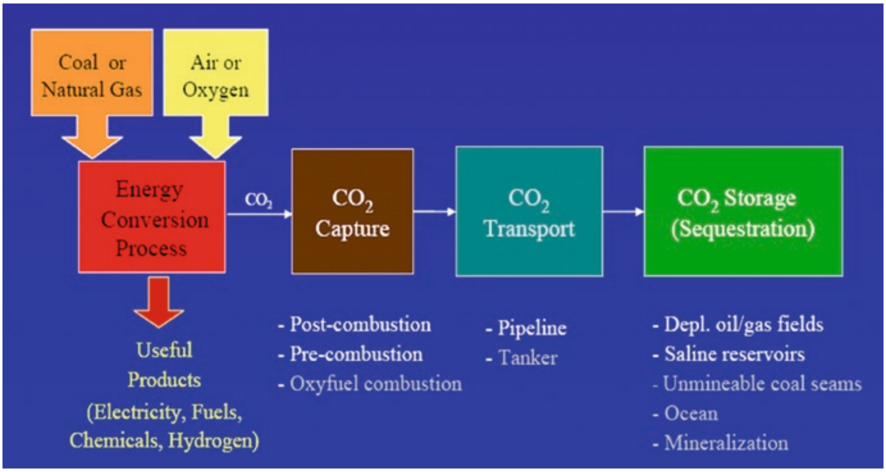

Fig. 2.15 Full carbon chain from fossil fuel input to carbon capture and sequestration

The last two steps in the carbon chain, pipeline transport and injection, will now be considered, as will their impact on COE estimated. These costs are already included in Tables 2.4 and 2.7; this section develops and discusses their cost basis. To estimate cost impact, a model of a typical CCS project is needed. Oil and gas reservoirs and enhanced oil recovery (EOR) are often discussed for geologic storage of CO_2. These storage sites-of-opportunity may play a role initially; but they have limited long-term potential because of the scale of CO_2 CCS that will be needed to make a major difference in managing CO_2 from coal-based power generation. Today, EOR uses 35–40 million tonnes of CO_2 per year which could be supplied by a few early CCS projects (see Table 2.1). Larger-volume, long-term storage for the U.S. will largely be in deep saline aquifers. These geologic formations underlie large portions of the U.S., particularly those areas that today have a lot of coal-based power generation and where additional coal-based generating capacity could be expected to be added as shown in Fig. 2.16. In fact, there is a high degree of coincidence between potential coal deposits, coal-based power generating sites, and potential geologic CO_2 storage sites.

The primary mode of CO_2 transport for sequestration operations will be via pipelines. There are over 2,500 km of CO_2 pipeline in the U.S. today, with a capacity in excess of 40 million tonnes CO_2/year. These pipelines were developed to support EOR operations, primarily in west Texas and Wyoming. In these pipelines, CO_2 is transported as a dense, single-phase fluid at ambient temperature and supercritical pressure. To avoid corrosion and hydrate formation, water levels are typically kept below 50 ppm. The pipeline technology is mature, and most costs can be estimated. The main unknowns are the costs of permitting, acquisition of right-of-way, and additional costs associated with local terrain (rivers, roads, high density inhabited areas).

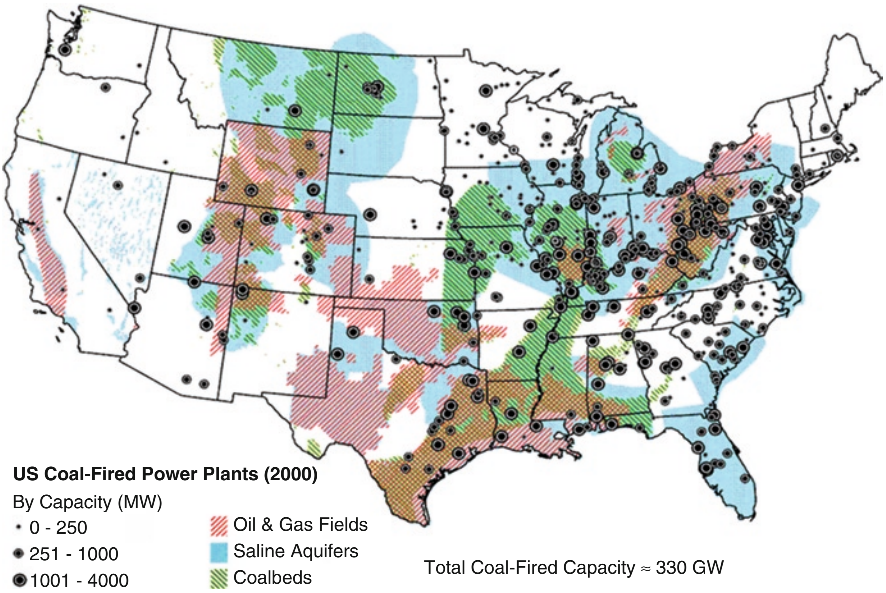

Fig. 2.16 Location of deep saline aquifers, oil and gas fields, coal beds and coal based power plants for U.S. [10]

However, rather than having long-distance CO_2 pipelines running across the country, a typical CCS power plant project could be expected to look something like that illustrated in Fig. 2.17. It is expected that sufficient capacity would be accessible within about a 100 km radius for a good location. Location is important, but once sited the CO_2 storage requirement for the lifetime of the power plant, which would be of order a billion barrels of liquid $CO_{2,}$ should be within that area. The total reservoir CO_2 capacity must be sufficient so that by accessing different portions of the reservoir over the lifetime of the plant all the CO_2 captured can be safely stored.

The Transport and Storage (T&S) costs used here were updated to 2007 using recent reviews by McCollum and Ogden and by Tarka [36, 37]. Pipelining costs were updated using the Handy-Whitman Index of Public Utility Costs for Gas Transmission Line Pipe and Steel Distribution Pipe and operating costs updated using U.S. Bureau of Standards Producer Price Indices for the Oil and Gas Industry [37]. Capital costs were levelized over a 20-year period and include a 30% process contingency and a 20% project contingency. Monitoring costs are included and used the IEA Greenhouse Gas R&D Program [38]. This includes operational monitoring costs tracking the plume for 30 years and closure monitoring costs for the following 50 years. An operational fund is capitalized to cover the 80 year monitoring cycle. The storage site is chosen to be representative of a typical saline aquifer at a depth of 4,055 feet depth and 22 millidarcies permeability and 1,220-psi down-hole pressure. A $5 million initial site assessment was assumed. Costs were estimated from this basis.

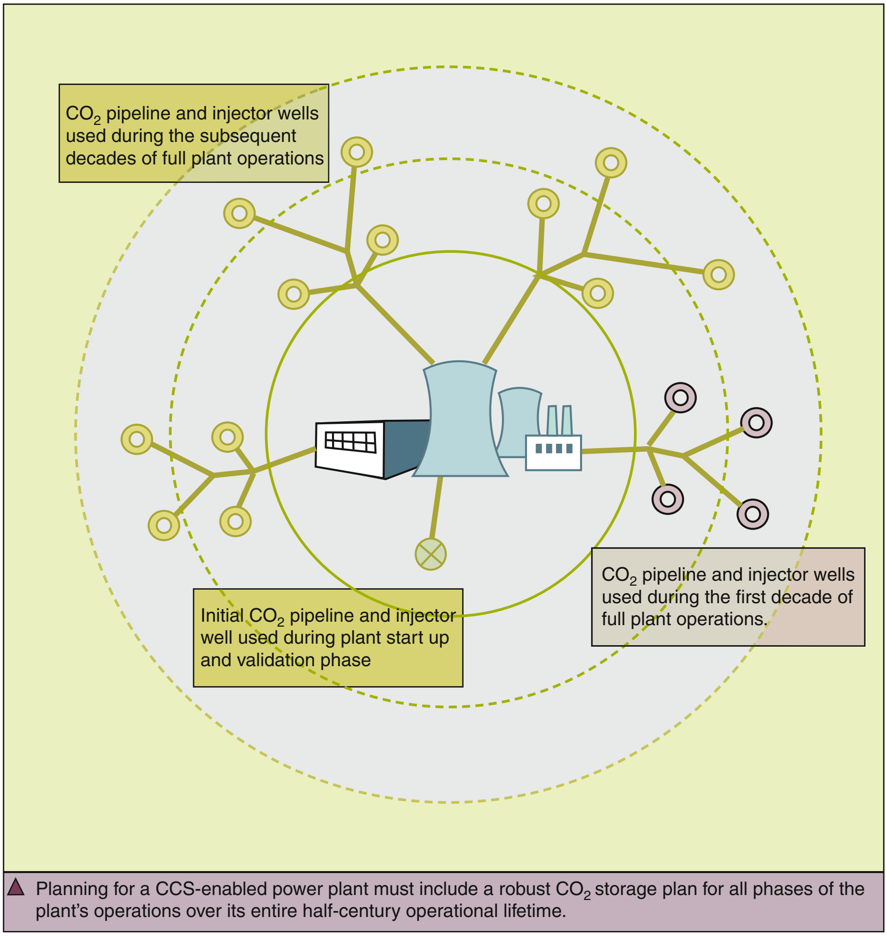

Fig. 2.17 Conceptual model of a typical CCS project (Courtesy Battelle, GTSP report)

The transportation costs dominate the CO_2 T&S costs and are highly non-linear with the amount of CO_2 transported. The economies-of-scale make transportation costs for large CCS projects much less expensive. For example, for 1 million tonnes of CO_2 per year (2,500 tonnes/day) the estimated transport cost is about $8.00 per tonne per 100 km; at 3.5 million tonnes CO_2 the estimated transport cost is about $5.00 and at 7 million tonnes of CO_2 per year the cost is about $3.00 per tonne per 100 km. These are typical values, but costs are dependent on pipeline costs which can be highly variable from project to project due to both physical (e.g., terrain the pipeline must traverse) and political considerations. In addition, there are a number of other issues that can have a significant impact on potential CCS projects. These include state and federal laws and regulations, and political, public, and environmental concerns.

For a 1 GW_e coal-fired power plant, pipeline capacity of about 6–7 million tonnes of CO_2/year would be needed. This would result in a transport cost of about \$3.00 per tonne of CO_2 per 100 km.

The major cost for injection and storage is associated with drilling the wells and the associated flow lines and connectors required for injection. However, capital requirements associated with storage are typically less than 20% of the capital requirements associated with transport. On the other hand, the operating and maintenance costs associated with storage are 30–40% of the O&M costs for transport. Other significant costs include site selection, characterization, and monitoring. In general, no additional pressurization of the CO_2 is required for injection because of the high pressure in the pipeline and the pressure gain due to the gravity head of the CO_2 in the wellbore. Monitoring costs are expected to be small, of order \$0.1–\$0.3 per tonne of CO_2 [39].

Costs for injecting the CO_2 into geologic formations will vary with formation type, its permeability, thickness, and other properties. For example, costs increase as reservoir depth increases and as reservoir permeability and injectivity decreases. Lower permeability requires drilling more wells for a given rate of CO_2 injection. A range of typical injection costs has been reported as \$0.5–\$8 per tonne of CO_2 [39]. For an average U.S. deep saline aquifer (1,000 m deep, 22 millidarcies permeability, and 160 m thick) the estimated storage cost is \$1.60 per tonne of CO_2 for 1 million tonnes/year (2,500 tonnes/day) storage rate and \$0.50 per tonne CO_2 for 3.5 million tonnes per year (10,000 tonnes/day) [37]. Although limited in scale, combining storage with EOR can help offset some of the capture and storage costs. EOR credits of up to \$20 per tonne of CO_2 may be obtained.

Representative projected costs, on a levelized basis per kW_e-h, are shown in Table 2.8 for coal-based PC and IGCC power generation. The costs for transport and storage are significant, but both are small and represent a small, acceptable fraction of the total cost. Transport and storage costs include the cost of constructing pipelines and of drilling the injection wells, as well as the system operating costs. The numbers used were updated to 2007 using typical terrain and saline reservoir properties [36, 37]. The largest cost is in CO_2 capture and compression (Table 2.8). For IGCC, the projected cost of CCS would increase the bus bar cost of electricity by about 40%, from 6.8 to about 9.4¢/kW_e-h. IGCC with CCS vs. PC venting would represent about a 50% increase in the bus bar COE. This electricity

Table 2.8 Cost of CCS projected for PC and IGCC generation with CO_2 capture

Technology	PC	IGCC
CCS Step	¢/kW_e-h	¢/kW_e-h
Capture	3.3	1.3
Compression	0.9	0.5
Transport	0.5	0.5
Injection	0.1	0.1
Totals	**4.8**	**2.4**

would be very low emissions electricity, including low CO_2 emissions. Furthermore, it is economically competitive with electricity generated by wind power and by new nuclear power plants [1].

Comprehensive geological reviews suggest that for carefully selected storage sites, there are no irresolvable technical issues for CO_2 injection and storage with respect to its efficacy and safety[10]. However, there are technical issues that require better understanding. We have 30 years of successful CO_2 injection experience from which we have found no critical issues. The Sleipner Project in Norway [40] has been injecting 1 million tonnes/year of CO_2 into the Utsira Saline Formation since 1996 using a single well bore. Weyburn in Canada [41] has injected 0.85 million tonnes/year of CO_2 into the Midvale reservoir for EOR since 2000, and In Salah [42] has been injecting 1 million tonnes/year of CO_2 into the water leg of the gas field for several years also. None of these projects have encountered any problems, and there is no sign of CO_2 leakage.

2.4 A Forward View

2.4.1 Retrofitting Existing Plants

Addressing the future of coal-based power generation raises many key issues and challenges. A number of these are analyzed next. To achieve really significant reductions, CO_2 emissions from the existing coal fleet will have to be reduced. This will require retrofitting CO_2 capture on existing units, or repowering them with high-efficiency technology with CO_2 capture such as IGCC-CCS or replacing them with other technology.

Retrofitting existing units involves several factors that significantly affect the economics and viability of the unit. These include unit age, size, and operating efficiency, as well as land availability or other space constraints at the plant site. Existing units are frequently smaller, have low generating efficiency, and may not have highly efficient emissions control systems relative to large, new builds. The energy requirement for CO_2 capture is usually higher for retrofits because of less efficient heat integration for sorbent regeneration in an existing plant. For power generation, plant output reduction approaches 40% vs. the 30% reduction for purpose-built plants [39, 43–45]. Existing plants that are not equipped for adequate NO_x control or with a flue gas desulfurization (FGD) system for SO_2 control must be retrofitted or upgraded for high-efficiency sulfur capture in addition to the CO_2 capture and recovery system. All these factors lead to higher overall costs for retrofits. Figure 2.18 illustrates the retrofit of a subcritical PC unit with MEA (monoethanolamine) flue gas scrubbing. The original unit had a generating efficiency of 35% (HHV) without CO_2 capture; after retrofit with CO_2 capture the original 500 MW_e unit produces only 294 MW_e and has a generating efficiency of 20.5% (HHV) or a 41.5% derating. The efficiency reduction for a

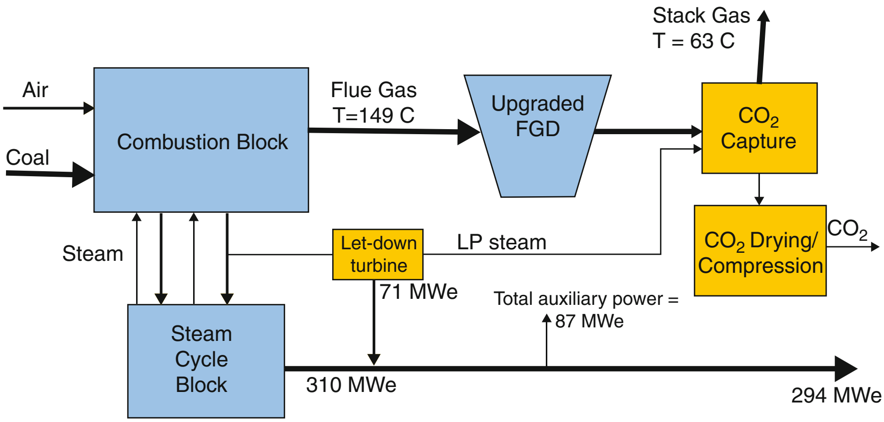

Fig. 2.18 Retrofit of a subcritical PC unit with amine CO_2 capture

CO_2 capture purpose-built unit would be about 28% (HHV) or a 28% derating. For the purpose-built unit, everything is optimally sized; for the retrofit unit, steam is diverted from the turbine for sorbent regeneration, and the turbine is operating at about 58% of design loading, far from its conditions for optimum performance.

If the original unit is fully paid off, the cost of electricity after retrofit could be slightly less to somewhat more than that for a new purpose-built PC plant with CO_2 capture based on the new capital required [43, 44]. However, an operating plant will usually have some residual value, particularly if flue gas clean-up technology has recently been added; and the reduction in plant efficiency and output, increased on-site space requirements, and unit downtime are all complex factors not fully accounted for in this analysis. For smaller, older units, rebuilding the entire boiler and power generation sections or replacing them with IGCC (repowering) may be the best alternatives [44, 45]. Generally, the cost of CO_2 avoided is expected to be 30–40% higher than for a purpose-built capture-plant. For example, an MEA retrofit of a supercritical PC is projected to cost almost as much as a new unit on a $/kW$_e$ basis from an Alstom retrofit design study [43]. Retrofit capture costs have been projected to range from 2 to 7¢/kWe-h from best to worst case scenarios considered with 90% CO_2 capture in a feasibility study by Alstom [46]. Further, retrofits require case-by-case detailed design-based examination. Although there is no one answer for existing subcritical PC units, CO_2 capture will likely be achieved through repowering with a supercritical PC unit with CO_2 capture or with oxyfuel or with IGCC-CCS or other technology, rather than retrofitting. A recent MIT symposium on retrofitting PC plants for CO_2 control addressed all of these issues but found no easy, cheap solutions [45]. The option of producing fuels and power from biomass and coal is a new option that is discussed in Chap. 3.

2.4.2 Electricity and CO_2 Avoided Costs

Figure 2.19 shows the levelized COE for coal- and biomass-based power generation and the components that make up the total cost. The COE for natural gas combined-cycle power generation with venting and with CCS for two natural gas prices is also included in Fig. 2.19 [11, 35, 47, 48]. As discussed above, with CO_2 venting the COE is lowest for conventional PC and about 10–15% higher with IGCC. The COE for NGCC is about the same as for PC for a gas price of \$6/GJ, but at a gas price of \$16/GJ it is more than twice that. The fuel cost is the largest COE driver in NGCC and is also large for biomass to power. Adding CCS increases the cost for all generating technologies but less so for technologies that involve gasification, for example IGCC vs. PC. As a result, coal IGCC with CCS is the most attractive technology, as is biomass to power (BTP) with CO_2 venting, their COEs are essentially the same.

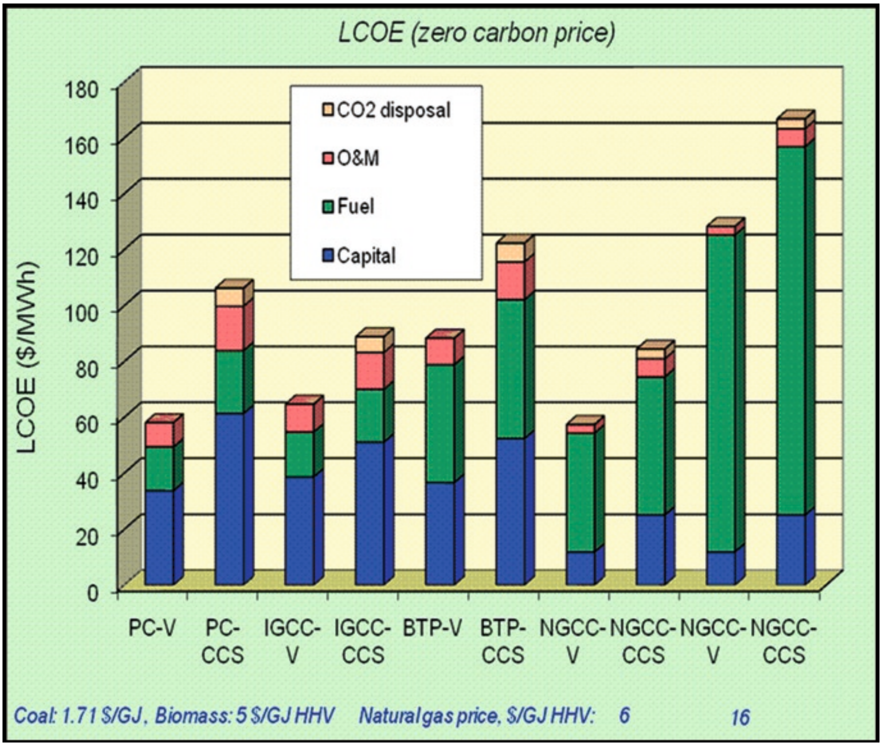

Fig. 2.19 Levelized cost of electricity for newly-built coal-based and biomass-based power generation technologies at study point-design conditions and zero price on CO_2 emission. Natural gas combined cycle generation with two natural gas prices included (\$100/MW_e-h equals 10¢/kW_e-h.) (Courtesy Williams et al. [11])

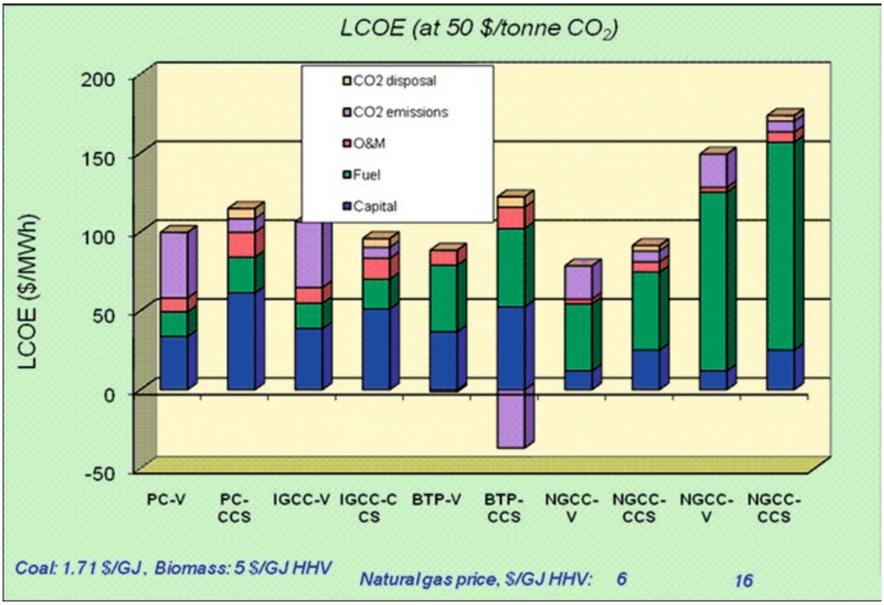

Fig. 2.20 Levelized cost of electricity for newly-built coal-based and biomass-based power generation technologies at the study point-design conditions with a \$50 per tonne price on CO_{2eq} emitted to the atmosphere. Natural gas combined cycle generation with natural gas is included for comparison (\$100/MW_e-h equals 10¢/kW_e-h) (Courtesy Williams et al. [11])

Figure 2.20 shows the impact of a \$50/tonne price on CO_{2eq} vented. This tends to level the COE of many of the technologies and makes IGCC with CCS the most economically attractive of the coal technologies. The COE of biomass to power with venting (BTP-V) is about \$9/MW_e-h cheaper then IGCC-CCS and would have no tax imposed on it because the life-cycle CO_{2eq} is essentially zero due to the fact that the CO_2 emitted is recaptured in the next plant growth cycle. Biomass to power with CCS (BTP-CCS) is about \$2/MW_e-h cheaper than BTP-V because of payment for the CO_2 removed from the atmosphere and geologically stored (negative bar on the graph). These payments more than offset the added capital and feedstock costs associated with CCS. Under these conditions, biomass to power is economically favored over coal to power.

Figure 2.21 provides key information on the impact of an increasing life-cycle Green House Gas (GHG) emission (CO_{2eq}) price on the COE for several power generating technologies, from the work of Williams and coworkers at PEI [11]. This plot is based on their single design-point study using a consistent database. Included is the impact of GHG emissions price on the cost of average grid power and on the cost of power from existing, fully paid-off, coal plants. Crossover points are the CO_{2eq} price at which economics would induce a shift from one technology to the other for new power plants. For example, the CO_{2eq} cost that would induce a shift from IGCC venting (CTP-V) to IGCC with CCS (CTP-CCS) is \$38/tonne

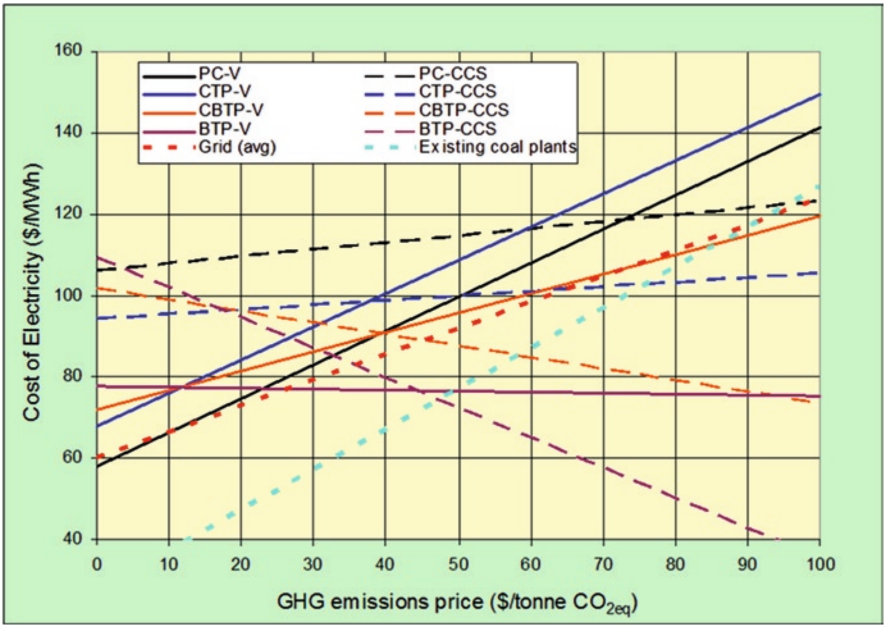

Fig. 2.21 Cost of Electricity (COE) as a function of GHG emissions price. Crossover points are the CO_2 prices required to economically induce a shift from one technology to the other. Also indicated is the impact of CO_2 price on the average cost of grid power today and the cost of power generated by existing coal plants (Courtesy Williams et al. [11])

CO_{2eq} (Fig. 2.21). The CO_{2eq} emissions price required to induce a shift from newly designed PC venting (PC-V) to newly designed IGCC with CCS (CTP-CCS) is about $50/tonne CO_{2eq} and to drive a shift from PC-V to PC-CCS requires a CO_{2eq} price of about $73/tonne. This is the situation which would exist when the demand for electric power is growing and new coal-based power plants are being designed and built. It would also be the situation for repowering old, obsolete power plants.

In the case of existing coal-based plants that are fully operational where there is insufficient growth in electricity demand to warrant new plants, as might be the case in the U.S., the relevant crossover point is between existing, venting PC plants and new IGCC with CCS (CTP-CCS). Under these conditions, a CO_{2eq} price of over $75/tonne would be required to induce the construction of a new IGCC plant with CCS (CTP-CCS). This approach would also apply to repowering existing PC plants with IGCC with CCS.

These CO_{2eq} price cross-over points suggest that significant shifting to IGCC or other coal-based power plants with CCS would occur at a relatively low CO_{2eq} price (less than ~$40/tonne) in economies that have growing electricity demand, i.e. are building new plants. In economies with stagnant electricity demand, because of conservation efforts, etc., the CO_{2eq} price to induce a shift would have to be much higher (more like $75/tonne), to induce a switch from existing, venting PC plants to new IGCC plants with CCS (or whatever is the lowest coal-based generating technology with very low carbon emissions).

Biomass to power plants (BTP) using biomass gasification both with CCS and without CCS would economically replace existing coal plants at an emissions price of about \$50/tonne CO_{2eq}. For new plants, biomass to power (BTP-V) is projected cheaper than IGCC with CCS (IGCC-CCS) for all CO_{2eq} prices, and the crossover point for biomass to power with CCS (BTP-CCS) is less than \$30/tonne CO_{2eq} for IGCC-CCS. If the estimated COE is low because of a low capital cost estimate or low biomass cost estimate, the appropriate curve shifts upward by that amount, but the crossover points remain within a relatively small CO_{2eq} price range.

Combined coal and biomass (~60%/40% on an energy basis) – based power generation (CBTP) without and with CCS have low crossover CO_{2eq} prices with the conventionally considered all-coal based power generation. These are basically all less than \$40/tonne CO_{2eq} for new plants. However, to replace existing PC plants, the existing emissions price would have to exceed \$55/tonne CO_{2eq}. The challenge with the biomass and the combined coal and biomass cases is the lack of experience with biomass gasification, and the availability of biomass. Biomass gasification is technologically feasible and has been commercially demonstrated, but it is not yet a really robust commercial technology. Biomass is a dispersed resource, and thus supplying large quantities of it to a given site on a continuous basis is a challenge. Because it is less dense and typically contains significant water, collection and transport over long distances is not economically attractive. This limits the size of potential plants. This makes coal plus biomass configurations more attractive because it provides economies of scale, and reduces CO_{2eq} emissions, while coal supplements available biomass. In addition, small amounts of biomass with coal (around 10% on an energy basis) in IGCC with CCS (CTP-CCS) can produce zero life-cycle GHG electricity.

The estimates developed here are all based on bituminous coal, for which the COE favors IGCC with CCS in a CO_2-constrained environment. Although, about 50% of U.S. coal reserves are bituminous, the remaining 50% are sub bituminous coal and lignite. Lower rank coals and higher elevation plant locations narrow the cost difference between IGCC and PC with CO_2 capture [10, 49]. Cost improvements for PC capture could make it economically competitive with IGCC in certain applications, and Oxy-fuel PC looks potentially competitive also. Thus, it is too early to decide which technology will be cheapest for coal-based power generation with CO_2 capture. All technologies need to remain under development and demonstration until there is sufficient commercial-scale experience to decide.

There is always a need for innovative technology in coal-based power generation to improve operations, increase generating efficiency, and to reduce emissions and CO_2 capture costs. A number of technologies are being developed to reduce cost and improve performance at the bench and pilot scale. However, it is important to note that conventional coal-based power generation is a mature technology, and PC units have been highly optimized. Technology already exists to capture CO_2 from PC and IGCC units, although it is typically applied at smaller scale in other applications. These technologies need to be commercially demonstrated, integrated, and optimized on the scale of power generation. Waiting for research to provide that "unique solution" is not a rational approach if there is any urgency to the CO_2 emissions issue. The rational approach is to put available commercial technology into practice, integrate it into the full generating and emissions control system, and begin to move along the learning-by-doing curve. This typically results in significant cost reductions, improved effectiveness and efficiency, and increased operability, reliability, and robustness. Rubin and coworkers at Carnegie Mellon University have studied the impact of learning-by-doing on cost for a number of technologies, including the power industry (e.g. see [50]). From the historical experience curves for a range of power generation technologies, LNG plants and oxygen and hydrogen production, Rubin et al. [50] estimated that for the generating technologies considered above, the CO_2 capture cost could undergo a 13–15% capital cost reduction and a 13–26% total cost reduction with 100 GW_e of new installed capacity. This is in addition to the cost reductions that will also be taking place in the base plant, such as IGCC which will be undergoing learning-by-doing cost reductions with increasing commercial applications. The same can be said for the CO_2 transport and storage component of the total generating and CCS chain.

Commercial technologies exist that can be utilized and integrated to achieve effective power generation with CCS today. These have been applied in commercial operation but frequently at a smaller scale than required for power generation. Application of these technologies at commercial power-plant scale will ultimately result in significant improvements in them and in significant cost reductions. Similarly, CO_2 sequestration (geologic storage) is commercially demonstrated at the 1 million tonnes per year at several locations in the world, and more demonstrations are planned internationally. The DOE Regional Partnership program has started to develop a geologic database but needs to accelerate and expand in scale.

Geologic storage still needs full-scale, well-monitored demonstrations at several locations and in different geologies in the U.S. to develop the needed site choice, permitting, monitoring and closure procedures and to gain needed public and political support for the more widespread application of the technology. These are large-scale, expensive activities, which if successfully demonstrated and applied are mainly aimed at benefiting society, and thus, society has a stake in supporting them. The can also be said in support for combined demonstration programs among several countries that depend heavily on coal-based power generation (such as India, China, and the US) and are likely to remain heavily dependent on coal-based power generation for the foreseeable future. Such demonstrations can take up to a decade to plan, build, and operate to gain desired learning. Thus, there is urgency to start down the path.

In addition to CO_2 emissions, criteria emissions from coal-based power generation can be very low if the available control technologies are applied. When CO_2 capture is applied, these criteria emissions can be expected to be even lower, resulting in a small environmental footprint for clean coal technology. With CO_2 capture and sequestration, "clean coal" can provide base-load electricity that is cost competitive with wind and new nuclear and can continue to help maintain our energy diversity. Thus, "clean coal" would appear to continue to be an economic choice for base-load power generation of very low emissions electricity, including low CO_2 emissions.

In summary with respect to the path forward:

- The technologies required for CO_2 capture with power generation are commercial and can be expected to improve in cost and performance from operation at scale and learning-by-doing. Major R&D developments are not needed to begin applying them now. However, major R&D will be needed to support their application and to help drive improvements in them and the development of new and improved technologies. The order of commercial readiness is: (1) IGCC-CCS, (2) PC with post capture, and (3) oxy-fuel.
- It is technically feasible to safely and effectively store large quantities of CO_2 in deep saline aquifers, and the U. S. storage capacity in such reservoirs appears very large. This needs to be clearly demonstrated on a commercial scale and some technical issues need resolution. Improved storage capacity estimates need to be made by country. The U.S. appears to have storage capacity potential in excess of several hundred to over a 1,000 gigatonnes of CO_2. China appears to have large storage capacity close to with much its coal use, but India may have a more limited storage potential [10].
- A broad range of regulatory issues, including: permitting guidelines and procedures, liability and ownership, monitoring and certification, site closure, remediation, require resolution so that projects can proceed forward in a smooth, efficient manner.
- For CCS to be available to apply on a large scale, it is critical to gain political and public confidence in the safety and efficacy of geologic storage.

To resolve these issues and establish CCS as a viable technology for managing CO_2 emissions, it is necessary to carry out 3–5 large-scale CCS demonstration projects in the U.S. and 7–12 globally at the 1 million tonnes CO_2 per year scale, using different generation technologies, focusing on different geologies, and operated for several years [10]. Effective demonstration of technical, economic, and institutional features of CCS at commercial scale with coal combustion and conversion plants, will: (1) give policymakers and the public confidence that a practical carbon mitigation option exists, (2) shorten the deployment time and reduce the cost for carbon capture and sequestration when a carbon emission control policy is adopted, and (3) maintain opportunities for the lowest cost and most widely available energy form to be used to meet the electricity needs of the U.S. and the developing world in an environmentally acceptable manner. If completed expeditiously, this program can provide the U. S. and the rest of the world with robust technical options for addressing CO_2 emissions from power generation and for liquid transportation fuels production from coal as discussed in Chap. 3. If the U.S. took the lead in these activities, it could also provide a broad technology base for U.S. companies to apply globally and would also strengthen our engineering and technology base to deal with other energy/technology issues in the future.

With a robust set of technology options, it is in theory feasible to markedly reduce CO_2 emissions from coal-based electric power, but to drive this, the price set on CO_{2eq} emissions will have to be high. This is particularly the case if power demand does not grow and the activity focuses on replacing units in the existing fleet. With growth in power demand and with the end-of-life retirement of existing units the emissions reduction will occur at a lower emissions price. IEA projects in the World Energy Outlook 2008 that the GHG emissions price will have to be about \$90/tonne CO_{2eq} by 2030 to realize the 550 stabilization trajectory [51]. EPRI gives a detailed analysis of reductions potential in the generating portfolio including the role of coal with CCS [52]. Chap. 3 presents an important route for achieving significant reduction in emissions associated with coal-based power generation at a significantly lower cost.

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