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Fossil Energy

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Executive Summary

Analysis in Chapter 12 shows that a radical transformation of the fossil energy landscape is feasible for simultaneously meeting the multiple sustainability goals of wider access to modern energy carriers, reduced air pollution health risks, enhanced energy security, and major greenhouse gas (GHG) emissions reductions.

Fossil fuels will dominate energy use for decades to come. Two findings apply to developing and industrialized countries alike. First, fossil fuels must be used judiciously – by designing energy systems for which the quality of energy *supply* is well matched to the quality of energy *service* required, and by exploiting other opportunities for realizing high efficiencies. Second, continued use of coal and other fossil fuels in a carbon-constrained world requires that carbon capture and storage (CCS) becomes a major carbon mitigation activity.

Since developing and industrialized countries have different energy priorities, strategies for fossil energy development will be different between these regions in the short term, but must converge in the long term. The focus in developing countries should be on increasing access to modern and clean energy carriers, building new manufacturing and energy infrastructures that anticipate the evolution to low carbon energy systems, and exploiting the rapid growth in these infrastructures to facilitate introduction of the advanced energy technologies needed to meet sustainability goals. Rapidly growing economies are good theaters for innovation. In industrialized countries, where energy infrastructures are largely already in place, a high priority should be overhauling existing coal power plant sites to add additional capabilities (such as coproduction of power and fuels) and CCS. (Simply switching from coal to natural gas power generation without CCS will not achieve the ultimately needed deep carbon emission reductions.)

Analysis in Chapter 12 highlights the essential technology-related requirements for a radical transformation of the fossil energy landscape: (i) continued enhancement of unit energy conversion efficiencies, (ii) successful commercial deployment of carbon capture and storage, (iii) co-utilization of fossil and renewable energy in the same facilities, and (iv) efficient coproduction of multiple energy carriers at the same facilities.

Among the fossil fuel-using technologies described in this chapter, only coproduction strategies using some biomass with the fossil fuel and with CCS have characteristics such that they can simultaneously address all four of the major energy-related societal challenges identified by GEA, as shown in Figure 12.1. It is plausible that these technologies could begin to be deployed in the relatively near term (2015–2020) because nearly all of the technology components of such systems are already in commercial use. Hydrogen made from fossil fuels with CCS is an energy option in the long term, but infrastructure challenges associated with hydrogen distribution and end use (especially for mobile applications) amplify the magnitude of the fossil energy challenge and are likely to limit hydrogen as an option in the near term. Other energy options may emerge in the post-2050 timeframe, and some ideas are touched upon briefly in this chapter.

The energy performance, cost, and GHG emissions of many of the power generation and coproduction technologies described in this chapter are summarized in Table 12.1 and Table 12.2. (Similar metrics for hydrogen production from fossil fuels and for smaller scale coproduction systems that coprocess biomass and coal or biomass and natural gas can be found in the main body of this chapter.)

Table 12.2 includes coal-biomass coprocessing systems with CCS that provide liquid fuels and electricity via coproduction. These technologies are attractive both as repowering and repurposing options for existing coal power plant sites and for greenfield projects. The economics of such systems depends on the greenhouse gas emissions price and the oil price, as discussed quantitatively in this chapter.

Clear benefits of this coproduction approach include:

- greatly reduced carbon emissions for electricity and transportation fuels;

- enhanced energy supply security;
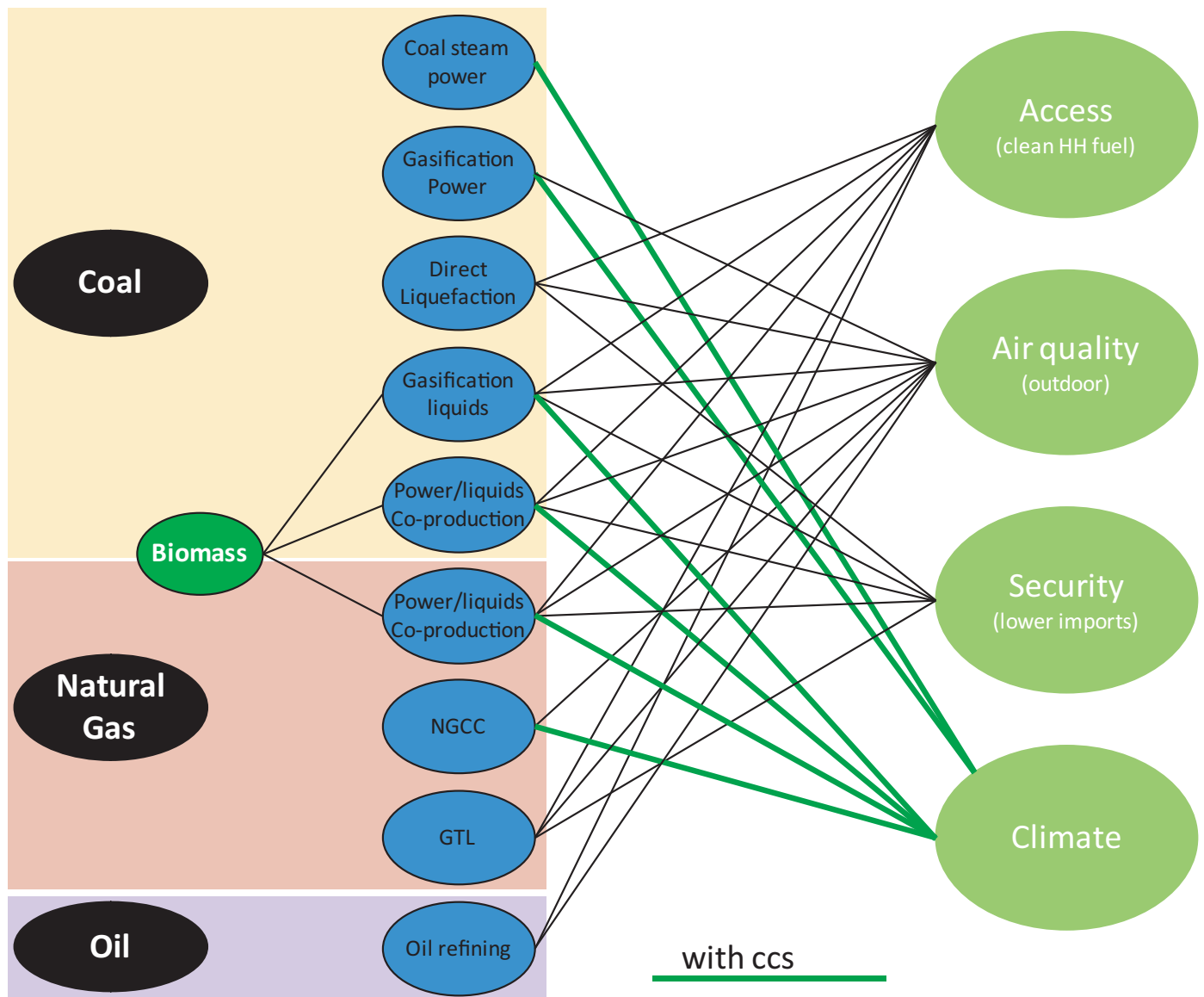
Figure 12.1 | Commercial or near-commercial fossil energy technologies discussed in this chapter and their suitability for addressing four major energy-related challenges. Among the listed technology options, only coproduction systems (that include coprocessing of some biomass) are capable of addressing all major challenges.

- provision of transportation fuels that are less polluting in terms of conventional air pollutants than petroleum-derived fuels;

- provision of super-clean synthetic cooking fuels such as liquefied petroleum gas (LPG) and dimethyl ether (DME) as alternatives to cooking with biomass and coal, which is critically important for developing countries; and

- greatly reduced severe health damage costs due to particulate matter ($PM_{2.5}$) air pollution from conventional coal power plants.

Coprocessing biomass with coal in these systems requires half or less biomass to provide low-carbon transport fuels as required for advanced fuels made only from biomass, such as cellulosic ethanol.

Table 12.1 | Performance and cost estimates in US$_{2007}$$ from this chapter for power generating technologies under US conditions. (To express costs in other-year US$, use the Chemical Engineering Plant Cost Index as shown in Figure 12.4 and discussed in text accompanying it.)

	Installed cost (US$/kW$_e$)	Capacity (MW$_e$)	Levelized electricity cost[a] (US$/MWh)	Plant inputs (MW HHV)			Life cycle GHG[c] kgCO$_2$-eq per MWh
				Coal	Biomass[b]	Natural gas	
WITHOUT CO$_2$ capture and storage							
Sub-critical pulverized coal	1598	550	62	1496			896
Super-critical pulverized coal	1625	550	61	1405			831
Coal-IGCC (GEE radiant)	1865	640	68	1673			833
Coal-IGCC (Conoco-Phillips)	1788	623	65	1586			823
Coal-IGCC (Shell)	2076	636	72	1546			787
Coal-IGCC (GEE quench)	1901	528	69	1405			833
Biomass IGCC (Carbona)	2008	317	92		699		25
NGCC (F class GT)	572	560	51			1102	421
WITH CO$_2$ capture and storage							
Sub-critical pulverized coal	2987	550	114	2211			187
Super-critical pulverized coal	2961	546	111	2004			171
Coal-IGCC (GEE radiant)	2466	556	92	1709			138
Coal-IGCC (Conoco-Phillips)	2508	518	94	1634			162
Coal-IGCC (Shell)	2755	517	101	1616			136
Coal-IGCC (GEE quench)	2677	435	100	1405			126
Biomass IGCC (Carbona)	2779	259	129		699		−776
NGCC (F class GT)	1209	482	77			1102	110

a Assuming capacity factor of 0.85. Prices assumed (US$/GJ$_{HHV}$) for coal, biomass, and natural gas are US$2.04, US$5, and US$5.11, respectively.
b As-received biomass moisture content is 15% by weight.
c Includes GHG emissions associated with feedstock production and delivery to the power plant.

Coproduction also represents a promising approach for gaining early market experience with CCS, because CO$_2$ capture is easier in coproduction than for stand-alone power plants. In the near term, coproduction could serve as a bridge to enabling CCS as a routine activity for biomass energy, with corresponding negative greenhouse gas emissions, in the post-2030 era. Analysis in this chapter shows that this could plausibly become a major industrial activity under a carbon mitigation policy for economically poor but biomass-rich regions, where it could make clean cooking fuels widely available and affordable in the regions while making major contributions to decarbonization of the transport sector worldwide.

No technological breakthroughs are needed to get started with coproduction strategies, but there are formidable institutional hurdles created by the need to manage two disparate feedstocks (coal and biomass) and provide

Table 12.2 | Summary of performance and cost estimates in US$_{2007}$$ from this chapter for alternative coproduction systems. Electricity is coproduced (to greater or lesser degree) with liquid fuels in all of these systems. FTL refers to Fischer-Tropsch liquids. MTG stands for methanol-to-gasoline. (To express costs in other-year US$, use the Chemical Engineering Plant Cost Index as shown in Figure 12.4 and discussed in text accompanying it.)

| | Installed cost US$/(bbl$_{eq}$/d)[a] | Capacity (bbl$_{eq}$/d)[a] | O&M 10^6US$/yr | Plant Inputs[b] | | Plant Outputs[b] | | | | GHG Emission Index (GHGI)[d] |
				Coal MW$_{HHV}$	Biomass[c] MW$_{HHV}$	Synthetic Diesel MW$_{LHV}$	Synthetic Gasoline MW$_{LHV}$	Synthetic LPG MW$_{LHV}$	Electricity MW$_e$	
WITHOUT CO$_2$ capture and storage										
Coal FTL	97,033	50,000	194	7559	9	2006	1153		404	1.71
Coal MTG	80,757	50,000	162	6549	0		2913	309	126	1.76
Coal FTL/ Power	122,958	35,706	176	7559		1431	825		1260	1.31
Coal MTG/ Power	126,167	32,579	164	6549			1898	202	959	1.37
Biomass FTL	160,189	4521	29		661	182	104		42	0.063
Biomass MTG	171,520	4630	32		661		270	28	32	0.066
WITH CO$_2$ capture and storage										
Coal FTL	98,372	50,000	197	7559		2006	1153		295	0.89
Coal MTG	82,099	50,000	164	6549			2913	309	36	0.97
Coal FTL/ Power	128,093	35,706	183	7559		1431	825		1058	0.70
Coal MTG/ Power	132,293	32,579	172	6549			1898	202	760	0.56
Biomass FTL	162,927	4521	29		661	181	105		31	−0.95
Biomass MTG	174,131	4630	32		661		270	28	20	−1.07
C+B FTL	139,091	9845	55	804	661	395	227		53	0.029
C+B MTG	129,200	10,476	54	781	661		610	69	11	0.018
C+B FTL/ Power	177,526	8036	57	1011	661	322	186		257	0.093
C+B MTG/ Power	180,110	11,582	83	1651	661		675	68	292	0.089

a bbl$_{eq}$/d is energy-equivalent barrels (LHV basis) per day of petroleum-derived fuels that could be replaced by the synthetic liquids.
b LHV is lower heating value and HHV is higher heating value.
c As-received biomass moisture content is 15% by weight.
d GHGI = system wide life cycle GHG emissions for production and consumption of the energy products divided by emissions from a reference system producing the same amount of liquid fuels and electricity. Here the reference system consists of equivalent crude oil-derived liquid fuels plus electricity from a stand-alone new supercritical pulverized coal power plant venting CO$_2$. See Table 12.15, note (c) for additional details.

simultaneously three products (liquid fuels, electricity, and CO$_2$) serving three different commodity markets. Creative public policies can help overcome these and other hurdles. Most importantly:

- Policy is urgently needed that sets a price on greenhouse gas emissions high enough to motivate CCS as a commercial activity.

- Stricter limits on air pollution are needed, especially from existing coal power plants and from indoor direct combustion sources. For the latter, policies should be designed to induce a shift, especially among the poor, from cooking by direct combustion of biomass or coal to using clean fluid fuels. Added costs that would result from

stricter air pollution limits can be justified on the basis of the large reductions in public health damage costs that would follow.

- Incentives are urgently needed that specifically target integrated CCS demonstration projects at megascale. To minimize spending on such incentives, governments should aim to pursue projects from which maximum learning is derived per dollar spent. This would include multilateral financial support for these demonstrations, since all countries needing CCS technologies will benefit from these early projects if the learning is well documented and shared.

- Policies are needed that support early deployment of promising new technologies and systems at commercial scale, such as coproduction with CCS. Without incentives for first-of-a-kind projects that offer major public benefits, promising new technologies will enter the market slowly or not at all. Incentives should include ones that encourage new inter-industry partnerships where needed. It is desirable that policy instruments specify performance goals rather than specific technologies, and maximize use of market forces in meeting the goals.

- CO_2 storage prospects are not well known in many countries where sorely-needed clean liquid cooking fuels could be produced from coal or biomass while storing byproduct CO_2 underground. This is especially true for many biomass-rich but coal-poor countries. Detailed assessments of CO_2 storage prospects are needed on a reservoir-by-reservoir basis in these countries. Financial support for these assessments from the international community would be appropriate.

- International collaboration is needed to speed up the needed global energy transformation, including assistance from industrialized to developing countries for technological and institutional capacity development.

- New public policies are needed to facilitate industrial collaborations between companies producing transportation fuels, electricity, and clean cooking fuels and to encourage coprocessing of coal and biomass in regions having significant supplies of both (e.g., United States and China). It is desirable that policy instruments specify performance rather than technology and maximize use of market forces in meeting performance goals.

12.1   Introduction

In 2009, the world used 11,164 million tonnes of oil equivalent (Mtoe) or 469 exajoules (EJ) of commercial energy in total, nearly 90% of which was from fossil sources (BP, 2010). Due to advantages in cost, technological maturity and established industry and infrastructure, fossil energies are very likely to remain as a major component of world energy supply for several decades (especially coal-based power generation and liquid hydrocarbon fuels for transport), even as the world increasingly transitions to renewable energy technologies. At the same time, as discussed in earlier chapters, the world today faces four major challenges stemming from fossil energy use: a widespread lack of access to affordable modern energy carriers (Chapter 2), climate change (Chapter 3), air pollution (Chapter 4), and energy insecurity (Chapter 5). Given that continued use of fossil fuels is likely for at least the next several decades, how can they be used to address effectively these four challenges? This question frames the content of this chapter. Figure 12.2 shows the broad filtering criteria applied to focus the discussion in this chapter.

A technology "missing" from Figure 12.2 is combined heat and power (CHP). Large energy and environmental benefits can be achieved by replacing separate stand-alone power and heat production systems with CHP. Carbon emission reductions can be especially significant when stand-alone coal-fired systems are replaced with natural gas fired

CHP systems (Krause et al., 1994). We do not discuss CHP in this chapter in large part because the analysis presented on this topic in the World Energy Assessment (Williams, 2000) is still relevant today.

Hydrogen as a vehicle fuel is also not analyzed in this chapter. Technologies for fossil fuel conversion to hydrogen are described, but because hydrogen distribution and end-use infrastructural challenges associated with using it in vehicles likely would require at least several decades to overcome, the emphasis on transportation fuels in this chapter is on liquid fuels that can be made from hydrocarbon (fossil or biomass) resources.

In Chapter 12, power generation technologies are discussed in Section 12.2 with an emphasis on their ability to reduce carbon emissions. Section 12.3 discusses the possibilities for carbon mitigation in conventional petroleum refineries. Section 12.4 discusses alternative transportation fuel technologies that can ease energy security tension and also help reduce carbon emissions from transportation. Section 12.5 discusses roles of non-petroleum feedstocks for production of clean household fuels that can help to address the problem of the widespread lack of access to modern energy carriers. In Section 12.6, strategies for coproduction of electricity and fuels are discussed. These offer the prospects for comprehensive solutions to using fossil fuels efficiently, economically, and with low environmental impacts, both in retrofitting
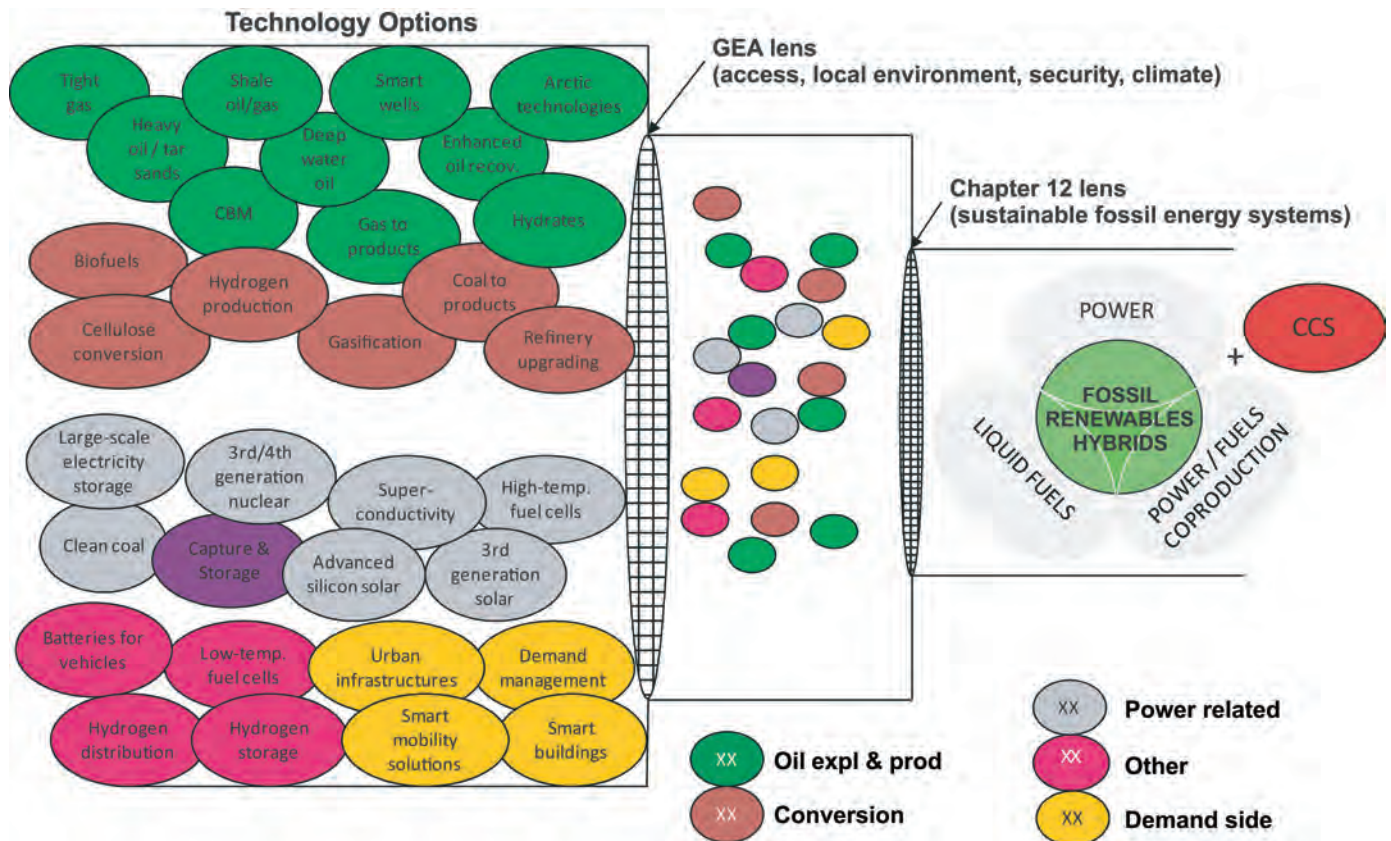

Figure 12.2 | Technology filters for this chapter.

existing energy facilities and in new installations needed to meet growing energy demands. Section 12.7 touches briefly on long-term technology options. Section 12.8 steps back from technology to consider strategic and policy issues.

12.2   Fossil Energy Technologies for Power Generation

For the foreseeable future, electricity will be one of the major energy carriers used by society. The problem lies in the large amount of fossil energy (and emissions) associated with electricity generation today to meet global demands.

Fossil fuels are the predominant primary energy at present in the world, accounting for nearly 90% of commercial energy use (BP, 2010). They are also the dominant fuel for power generation: producing about two thirds of our electricity today and projected to provide a similar fraction in 2035 (IEA, 2010). Today, fossil fuels are the most mature and economic source for power generation. However, they also account for most local conventional pollution and global carbon dioxide emissions. The future of fossil energy power generation in a carbon-constrained world depends on a compromise between growth in electricity demand and reduction in carbon dioxide emissions.

This section focuses on comparing the energy, environmental, and economic performance of fossil energy power generation technologies including coal-steam power, integrated coal gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) with and without carbon capture and storage (CCS). The section also touches on other issues related to sustainable development, including water usage, health damage from environmental pollution, and co-utilization of coal with biomass, reflecting the intention of this section to explore alternatives for using fossil energy wisely and with lower carbon emissions.

12.2.1   Overview of Global Electricity Demand and Supply

The International Energy Agency (IEA) describes current and projected future electricity demand and supply (IEA, 2010). Here we cite relevant numbers from the IEA to give a general overview of fossil energy power generation.

12.2.1.1   Current Electricity Demand and Supply

Electricity is the "blood" of modern society that supports human prosperity. Electricity demand has invariably increased along with economic growth. In 2008, world end-use energy utilization was 8423 Mtoe (354 EJ) (IEA, 2010), including coal, oil, natural gas, electricity, heat, biomass, and waste. Oil usage ranked first with a fraction of 42%. Electricity was second, at 17%. This indicates the importance of electricity in modern society.

In 2008, 16,814 terawatt hours (TWh) of electricity was consumed in end uses globally but with a regional imbalance. Member countries of the Organisation for Economic Co-operation and Development (OECD), with 18% of world population,[1] consumed 9244 TWh (55% of the total). Non-OECD countries, with 82% of world population, consumed 7570 TWh (45%). Per capita electricity demand in non-OECD countries was about 1300 kilowatt hours (kWh) per person, or only one sixth of that in OECD countries. Today, some 1.4 billion people still have no electricity supply, some 85% of them in rural areas (IEA, 2010). No access to electricity means not only energy deprivation, but also a lower capacity for economic growth, which has deep and long-term impacts.

The largest electricity consumption, 3814 TWh (23% of the world total) among OECD countries is by the United States. Among developing countries, China has the largest electricity consumption, 2884 TWh (15% of world total). Since China has about 20% of the world's population, per capita electricity consumption there is still lower than the world average.

The two countries also lead in power production. In 2008, the total electricity generation globally was 20,183 TWh, of which 53% was in OECD countries. The United States and China were the largest power-generating countries in OECD and in the developing world, respectively, accounting for 22% and 17% of global power production. Power generation in Africa was only 621 TWh, or 3% of the global total.

Total global power generating capacity was 4719 gigawatts (GW) in 2008. The primary energy sources used for power generation by percentage were coal (41%), oil (5%), natural gas (21%), nuclear (14%), hydro (16%), and other renewable energy (3%). The share of fossil energy power capacity (coal, oil, and gas) is 67%.

The primary energy used for power generation differs by geographical region, depending on resource endowments as well as the state of economic and technological development. In general, the share of nuclear power is much higher in OECD countries (26% in 2008) than in non-OECD countries (5% in 2008). This may be due to the advantage of OECD countries in mastering nuclear technology as well as their economic power. Hydropower depends on resource availability. The share of hydropower is 40% in Latin America, for example. In countries with abundant coal, coal-steam power is the low-cost choice. In China, India and the United States, respectively, coal power accounts for about 79%, 69%, and 49% of power generation. Natural gas is the best feedstock among fossil fuels for power generation in the sense of energy efficiency and environmental pollution. However, its application depends either on resources or on economic power. This resource is available in Russia, for example, with 48% of its power from natural gas, and in the Middle East, with 58%. The impact of economic power is evident in the use of natural gas by OECD countries, with 22% of their power from natural gas, in contrast to non-OECD Asia, with 10%.

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1   The total population of OECD countries was 1.18 billion in 2007. The total population in the world was 6.6 billion.

In China, because natural gas is rare and valuable, only 1% of power generation is from natural gas.

Globally, power generation is one of the major sources of CO_2 emissions, accounting for 11.9 gigatonne (Gt) in 2008, or 41% of the world's total fossil fuel CO_2 emissions. In many developing countries, however, conventional environmental pollution is considered a more urgent issue than CO_2 emissions because of the damage to the environment and human health it is causing today. China's emissions of sulfur oxides and nitrogen oxides (SO_x and NO_x) and dust were 25.9 million tonnes (Mt), 15.2 Mt, and 10.9 Mt in 2006. Contributions from power generation were 45%, 41%, and 29%, respectively (State Environmental Protection Administration of China, 2007). India's emissions of sulfur dioxide (SO_2), NO_x, and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$) were 6.7 Mt, 4.1 Mt, and 4.7 Mt in 2005. The reduction of conventional pollutants is imperative and urgent for both countries.

Public health costs of air pollution (especially SO_x, NO_x, and PM) from fossil fuel power generation are discussed later in this section. A large amount of new power generation infrastructure is being established daily in developing countries, especially in countries such as China and India that are undergoing rapid industrialization and urbanization. It is of great importance for the sustainable development of societies like China's and India's to find ways to simultaneously address conventional pollutant emissions and carbon emissions.

12.2.1.2   Future Electricity Demand and Supply Expansion

In the "current policies" scenario of the World Energy Outlook 2010 (IEA, 2010), world electricity demand is projected to increase 95% from 2008 to 2035, reaching 32,919 TWh. Every region of the world is projected to increase, though at different rates. The increase in non-OECD consumption accounts for 82% of the total projected global increase. Even in this case, annual per capita electricity consumption in non-OECD countries only reaches 4600 kWh, about half the average for OECD countries (9200 kWh). In Africa, annual per capita electricity consumption is projected to increase only modestly, to 700 kWh per person.

In this scenario, which assumes a future world with essentially no price on carbon emissions, China is projected to have the largest increase in both total electricity consumption and annual per capita consumption among developing countries. China's electricity consumption is projected to be 9420 TWh in 2035, surpassing the United States as the world's largest consumer. The large projected increase in annual per capita consumption in China brings it to 6400 kWh, a level slightly under 70% of the OECD average.

In the current policies scenario, world power production is projected to increase by 90% from 2008 to 2035, reaching 38,423 TWh. Likewise, total installed power generation capacity is projected to be 8875 GW,

representing an 88% increase compared to 2008. The share of electricity by source is projected to change only modestly from 2008 to 2035: coal from 41% to 43%, oil from 5% to 2%, natural gas from 22% to 21%, nuclear from 14% to 11%, hydropower from 16% to 13%, and renewable energy (other than hydro) from 3% to 10%.

Correspondingly, global CO_2 emissions from fossil fuels are projected to increase by 46%, going from 29,260 Mt in 2008 to 42,589 Mt in 2035. CO_2 emissions from power generation are projected to increase by 59% to 18,931 Mt. Together, China and India account for 75% of the total projected global increase in power sector CO_2 emissions from 2008 to 2035. Power sector emissions in 2035 are projected to be 7130 Mt in China and 2068 Mt in India. Overall, emissions from coal power top the global list. Emissions from coal power are projected to be 14,403 Mt, accounting for 76% of all power generation emissions and one third of total global fossil fuel emissions.

12.2.2   Steam Electric Power Generation Using Pulverized Coal

12.2.2.1   Process description

At present, coal-steam power based on the Rankine cycle is the most commonly applied power generation technology worldwide. Utility coal boilers are generally divided into pulverized coal (PC) and circulating fluidized bed (CFB) units, which describes the method of combustion in the furnace. Since it is the predominant form of coal-steam power generation, PC combustion is the main focus of the discussion here. Some basic information about CFB is provided in Box 12.1, including coal-biomass cofiring, an option that is attracting increased attention with the drive toward greater use of renewable energy.

Figure 12.3 shows the process of a typical pulverized coal combustion power plant. Major equipment includes the boiler, steam turbine, and electric generator. The system can be simply described by following the fluid loops inside the process.

• Water and steam loop: This is the working fluid in the power plant. Cold water from the condenser is boiled and converted into superheated steam and sent to the steam turbine where it expands to generate mechanical rotating power. This mechanical power drives an electric generator to generate electricity, which is then transformed into high voltage and sent into the electricity grid. The steam exhausted from the turbine is cooled in the condenser and then sent back to the boiler to repeat the cycle.

• Air-flue gas loop: Air from the atmosphere is pumped into the boiler furnace to provide combustion air to burn the coal, the hot combustion products from which heat the water-steam loop. After releasing heat, the flue gas first goes through a selective catalytic reduction unit to get rid of NO_x, then to an electrostatic precipitator to reduce

Box 12.1 | Other Combustion Options

Circulating fluidized bed (CFB) combustion power generation technology was originally developed as a low-cost approach to sulfur control and to facilitate the use of low-quality coals. Currently, the main objective is to facilitate the use of low-quality coals.

In fluidized bed coal combustion, coal is crushed into pieces smaller than 10 mm and mixed with a large amount of fluidized bed material to burn inside the furnace. The typical bed temperature is 850°C, an appropriate level to minimize formation of thermal NO_x. Limestone is fed into the furnace along with coal in order to absorb sulfur dioxide formed during combustion. Up to 90% or more of the sulfur can be removed by simply adding limestone. This makes CFB a favorite lower-cost clean coal technology in developing countries. In China, for example, more than 2000 CFB boilers are in operation and the largest unit capacity is 300 MW. Units up to 600 MW (supercritical CFB boilers) are under development.

The energy efficiency of CFB units in general scores moderately lower than their PC counterparts for the same steam parameters due to slightly higher parasitic power consumption. With regard to carbon emissions, CFB units are somewhat less competitive because limestone used for in-situ desulphurization emits CO_2. Capital costs are slightly higher than for PC plants because of the requirements for more auxiliary facilities and anti-erosion refractory.

Cofiring coal and biomass provides a flexible method for using biomass, the supply of which may fluctuate seasonally. Cofiring coal and biomass reduces net carbon emissions compared to pure coal burning. Cofiring can also increase the efficiency of biomass use compared to a small scale power plant fired purely by biomass. Cofiring with coal is an efficient and effective way to use biomass and also to offset carbon emissions from coal power generation, at least until large-scale biomass use for fuel production becomes a reality. As for capital cost, there is one plant in China that has retrofitted an existing 140 MW PC boiler to utilize up to 20% (heat) biomass. The results also would be indicative for a CFB boiler. The incremental cost corresponding to 20% biomass power is much lower than the specific initial capital investment of a new biomass-fired power plant – and its efficiency is much higher.

1. Steam generator
2. DeNOx plant
3. Air preheater
4. Fan
5. Electrostatic percipitator
6. Desulfurization plant
7. Stack
8. Steam turbine
9. Condenser
10. Pump
11. Feedwater heater
12. Feedwater tank
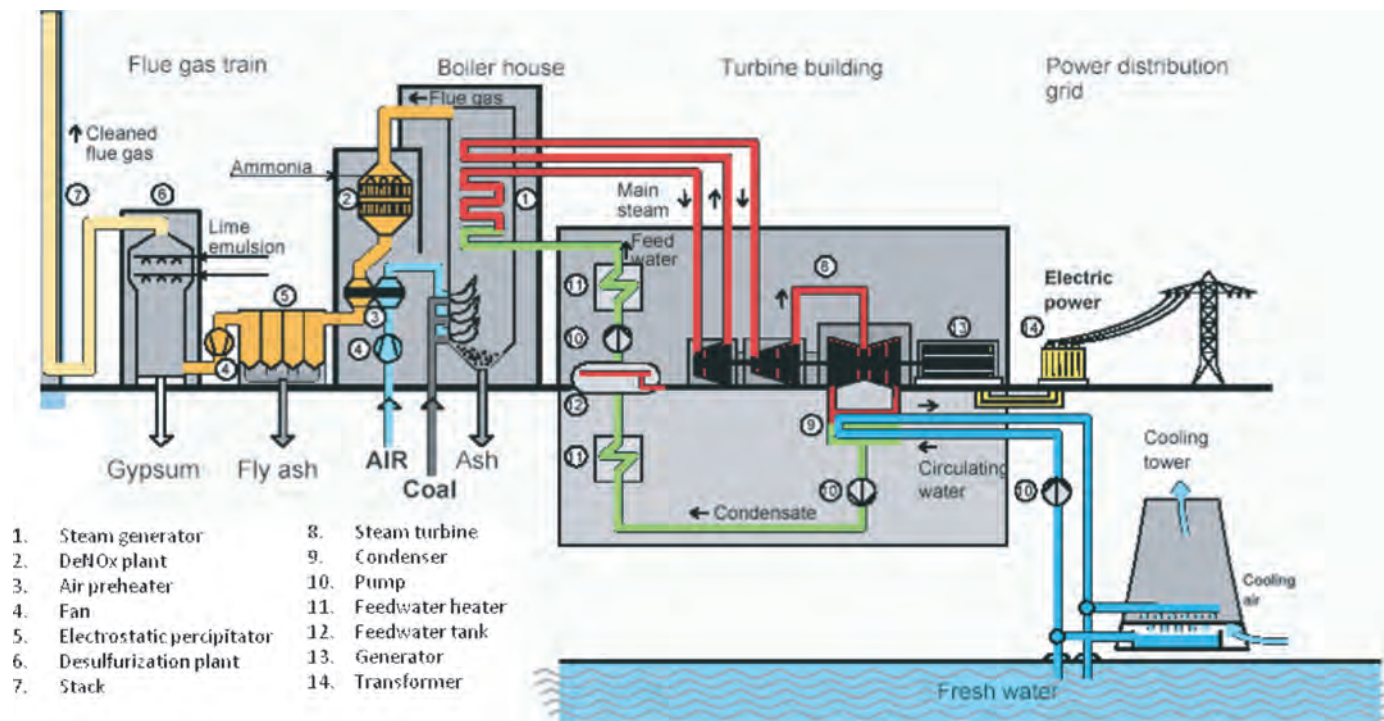13. Generator
14. Transformer

Figure 12.3 | Pulverized coal combustion power plant. Source: Termuehlen and Empsperger, 2003.
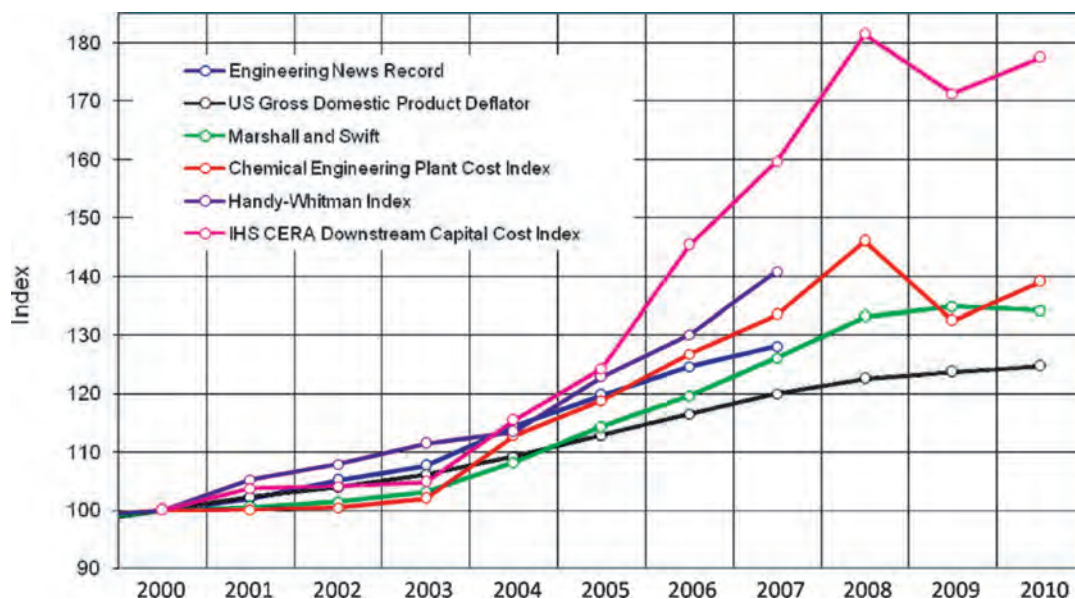
Figure 12.4 | Alternative cost indices, each normalized to 100 in year 2000. The Chemical Engineering Plant Cost Index is the most appropriate one to use for many of the energy supply systems discussed in this chapter. Source: updated from Kreutz et al., 2008.

dust, and then through flue gas desulphurization to get rid of SO$_x$. The cleaned flue gas returns to the atmosphere via the stack.

- Cooling water loop: Low temperature cooling water is sent to the condenser to condense the exhausted steam at the outlet of the steam turbine. Normally, the lower the temperature of the cooling water, the higher the efficiency of the power plant. Cooling water is supplied either from a water pond within the power plant or from the river or sea. In the first case, water is recycled and a cooling tower is required (as shown in Figure 12.3). Evaporation in the cooling tower causes a transfer of cooling water to the atmosphere, comprising the major water use for a power plant.

To further improve the efficiency of pulverized coal power plants, development efforts are ongoing on advanced supercritical pulverized coal designs, with steam operating temperatures of 700°C. The main hurdles are related to development of high-temperature materials. The efficiency target for such plants is as high as 50% (Quinkertz, 2010). Gains in efficiency translate to reduced CO_2 emission/MWh. It is conceivable that this technology may become available before carbon capture and storage can be widely applied, because it represents an incremental improvement on a technology with which there is already considerable commercial experience. Thus, this technology may serve to help reduce carbon emissions from coal-fired power generation in the near term.

12.2.2.2   Efficiency and Steam Conditions

The net efficiency of a power plant is defined as the amount of electric power sent to the grid divided by the total energy input as coal. The efficiency depends mainly on the temperature and pressure of the steam as it enters the steam turbine. Coal-steam power plants can be classified as subcritical, supercritical, and ultra-supercritical, depending on the conditions of the steam entering the turbine. Steam parameters and typical corresponding efficiency levels are shown in Table 12.3.

12.2.2.3   Construction Costs

There were sharp increases in construction costs for new power plants in the middle part of the past decade, particularly in OECD countries. The increases have been especially marked in the United States as evidenced by the much higher rate of increase than GDP of various cost indices relevant to the energy and power sectors (Figure 12.4). Table 12.4 provides a view from one power plant equipment manufacturer of the factors influencing cost trends. The main factors contributing to the increasing

Table 12.3 | Classification of coal-steam power plants according to steam conditions.

Classification of power plant	Temperature (C)	Pressure (MPa)	Efficiency (%)	Typical unit capacity (MW)
Subcritical	~540	16.7	38	300–600
Supercritical	~560	~25	40–42	600
Ultra-supercritical	>560	>25	42–45	600–1000

Table 12.4 | One power plant vendor's view of factors influencing power plant pricing.

	Price trend since 2003
Civil Engineering	
Construction Materials (cement, steel, etc.)	↗
Labour costs (local, international)	↗
Power Plant	
Main mechanical components (boiler, generator, turbine)	↑ (approx. +270%)
Other mechanical equipment (e.g. piping)	↑ (+150%)
Electrical assembly and wiring:	↑
-cables	(+150%)
-transformers	(+60%–90%)
Engineering and plant start up	↗
Additional factors	
Transportation and logistic costs	↗
Power plant demand	↗
Cost of capital and inflation	→

Note: Vertical arrow (↑) = large increase; slanted arrow (↗) = moderate increase; horizontal arrow (→) =no increase

Source: IEA, 2008a.

costs in OECD countries were (i) substantial increases in raw materials costs, e.g., a quadrupling in the cost of iron ore and a doubling in the price of steel between 2003 and 2008 (IEA, 2008a), (ii) higher demand for materials generally, (iii) higher crude oil prices, (iv) increases in labor costs due to shortages of engineering, construction, and procurement personnel, and (v) a weakening US dollar during the decade.

Cost escalations for other parts of the world may be different. As an example, Table 12.5 summarizes the actual capital investment for coal and natural gas power in China. The investment levels were quite stable during 2004–2007. The main reason for this is that the major component technologies are manufactured locally.

In this chapter, unless otherwise indicated, we have expressed costs in US$_{2007}$$. We have used the Chemical Engineering Plant Cost Index (CEPCI) to adjust costs from other year values. As Figure 12.4 shows, using the CEPCI and 2007 as the reference year captures most of the escalation observed in the decade: the index for 2007 is approximately the same as for 2009 (i.e., no relative price increases) and only modestly lower than the preliminary value reported for 2010.[2]

12.2.2.4   Carbon Capture from Coal Steam Power Plant

Two approaches can be considered for capture of CO_2 from a steam electric plant. One way is to capture CO_2 from the flue gases of a conventional

plant (referred to as post-combustion capture). A second alternative is to use oxygen rather than air for the combustion ("oxyfuel" combustion). The advantage of the latter over post-combustion is the greater ease of CO_2 separation from the flue gases, which is accomplished by condensing out water from the combustion product mix of mainly CO_2 and water vapor. Offsetting this advantage are the significant added costs for an air separation plant and the fundamental power plant redesign required. (See Chapter 13 for additional discussion of this technology.)

Representative mass and energy balances of subcritical and supercritical coal power plants with and without post-combustion carbon capture are shown in Figures 12.5 and 12.6. Their energy, economic and environmental performances are shown in Table 12.6.[3, 4] The important messages revealed by comparing power plants without and with CCS are:

- The energy efficiency of both subcritical and supercritical power plants decrease by ~12 percentage points with the addition of carbon capture and storage. This is mainly due to steam consumption for regeneration of the solvent used to capture the CO_2 and mechanical power consumption for CO_2 compression.

- Water consumption more than doubles in both cases due to the large amount of heat required for regenerating the solvent used to capture the CO_2.

- The cost of electricity will nearly double (Table 12.6).

12.2.3   Gasification-based Power Generation

12.2.3.1   Technology

The first demonstration of gasification-based power generation at a significant scale dates to the early 1970s in Europe (163 MW plant in Lünen, Germany (Morehead and Hannemann, 2005)) and the mid-1980s in the United States (100 MWe Cool Water project (Alpert et al., 1987)). Since this time there has been considerable development of the technology, several commercial demonstration projects, and a few fully-commercial implementations in applications with low-cost waste feedstocks such

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2   The GEA technical guidelines provide methodological assistance for readers who want to convert these numbers to alternative year prices, e.g. the 2005 numbers used in most other chapters.

3   In this table, and as much as possible elsewhere in this chapter, we show both lower heating value (LHV) and higher heating value (HHV) for fuels. We have chosen not to use only LHV (the convention in much of Europe) for several reasons: (*i*) LHV can be an ambiguous value in the case of biomass (and we include some analysis of biomass/coal systems in this chapter); (*ii*) the US convention for energy prices is HHV; (*iii*) using LHV implies that the latent heat of condensation from combustion of a fuel is not recoverable. In fact, it can, and is, recovered in some circumstances; and (*iv*) use of HHV in this chapter motivates a search for opportunities to capture this latent heat in other applications – and is thus a good index for a carbon-constrained world.

4   These performance and cost estimates (and some subsequent estimates in this chapter) are based on the work of Woods et al. (2007). At approximately the time the writing of this chapter was completed, an updating of the work of Woods et al. was published (Haslbeck et al., 2010). A comparison of estimates in the original study and the revised study reveals only modest differences in plant efficiencies and installed capital costs. For example, total installed plant costs ($/kW) in the revised study (in US$_{2007}$$) are lower by 1.5–5% for pulverized-coal plants and for natural gas combined cycle plants. Unit costs are 9–16% lower for coal integrated gasification combined cycle (CIGCC) plants.

Table 12.5 | Capital costs (nominal RMB/kW)[a] for thermal power plants in China.

Type / capacity	2004	2005	2006	2007
	Cost (2004 RMB/kW)	Cost (2005 RMB/kW)	Cost (2006 RMB/kW)	Cost (2007 RMB/kW)
Subcritical PC / 2x300 MW	4853	4596	4292	4401
Supercritical PC / 2x600 MW	4074	3919	3608	3643
Ultra supercritical PC / 2x1000 MW	4128	3924	3604	3724
NGCC / 2x300 MW, GE, 9F	3106	3060	3039	3155
NGCC / 2x180 MW, GE, 9E	3137	2946	2912	2998

a For reference, the exchange rate in mid-2008 was US$1 = RMB6.9.

Source: EPPDI and CPECG, 2008.

Figure 12.5 | Mass and energy balance of a typical subcritical power plant without and with carbon capture ('Vent' and 'CCS,' respectively). In the case with CCS, the net power output accounts for CO_2 compression to 153 bar, which is assumed to be sufficient to transport and inject the CO_2 into an underground storage reservoir. Source: based on Woods et al., 2007.

as petroleum residuals. Gasification-based power generation with fossil fuels, including coal and petroleum residuals, is thus commercial technology, but without widespread operating experience. A distinguishing feature of integrated gasification combined cycle (IGCC) technology is the very low emissions of conventional pollutants that can be achieved, especially SO_2 and particulates. Interest in IGCC has grown recently in part because of the prospectively lower cost of producing low-carbon electricity from coal compared to the cost with pulverized coal (PC) combustion technologies with post-combustion CO_2 capture.

Figure 12.7 is a simplified representation of a coal-IGCC system (CIGCC). Coal, water (or steam), and pure oxygen[5] are fed to a

5   The oxygen for gasification is produced in a dedicated air separation unit (ASU), with some or all of the air feed to the ASU coming from the compressor of the gas turbine. When 100% of the air used in the ASU originates from the gas turbine, the plant is regarded as fully integrated (and the name integrated gasification combined cycle derives from this feature) and has the highest efficiency in theory. In practice, however, full integration has proved operationally difficult. Most IGCC facilities today consider a maximum of 50% of the ASU air requirement being provided by the gas turbine.
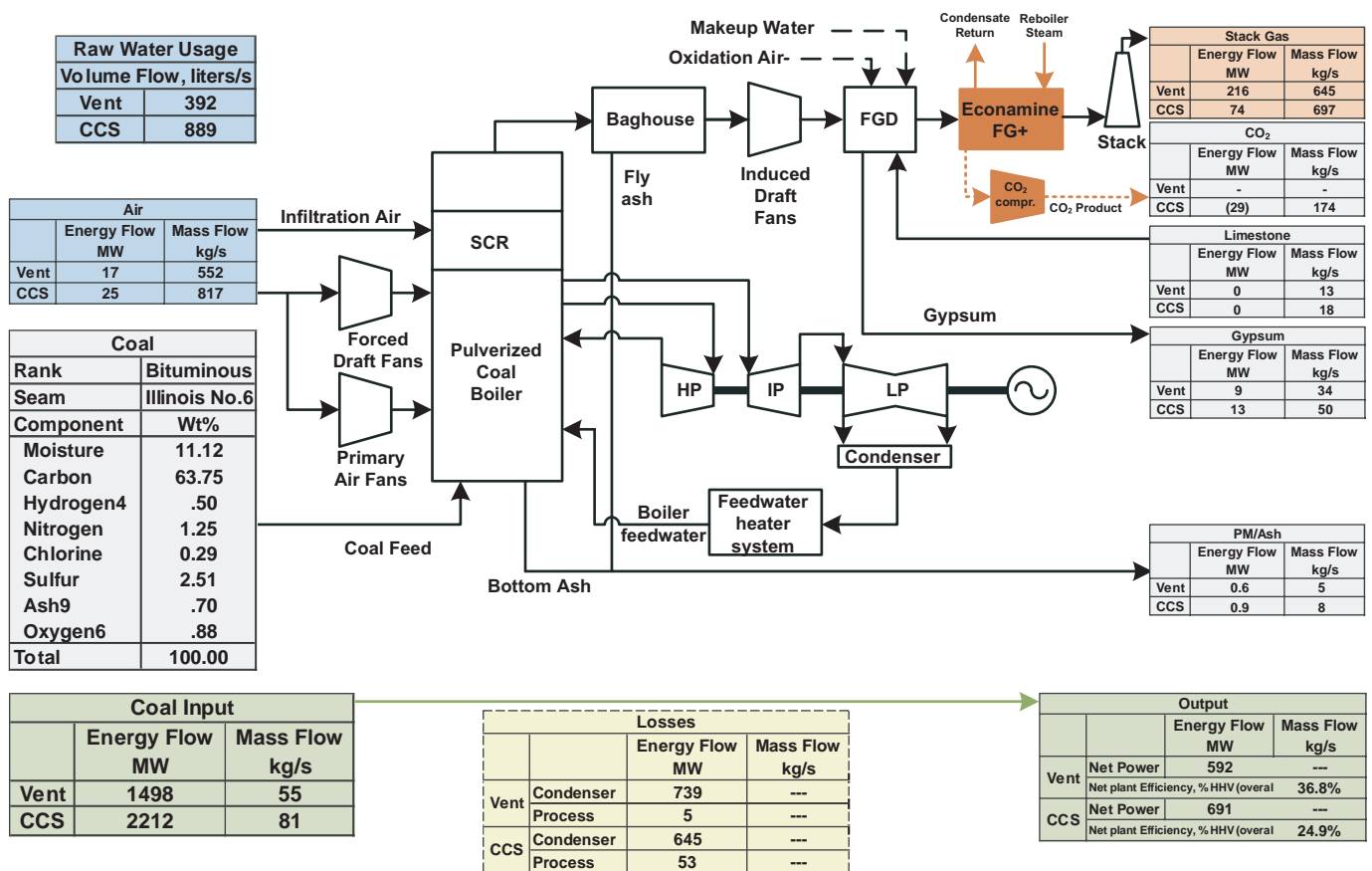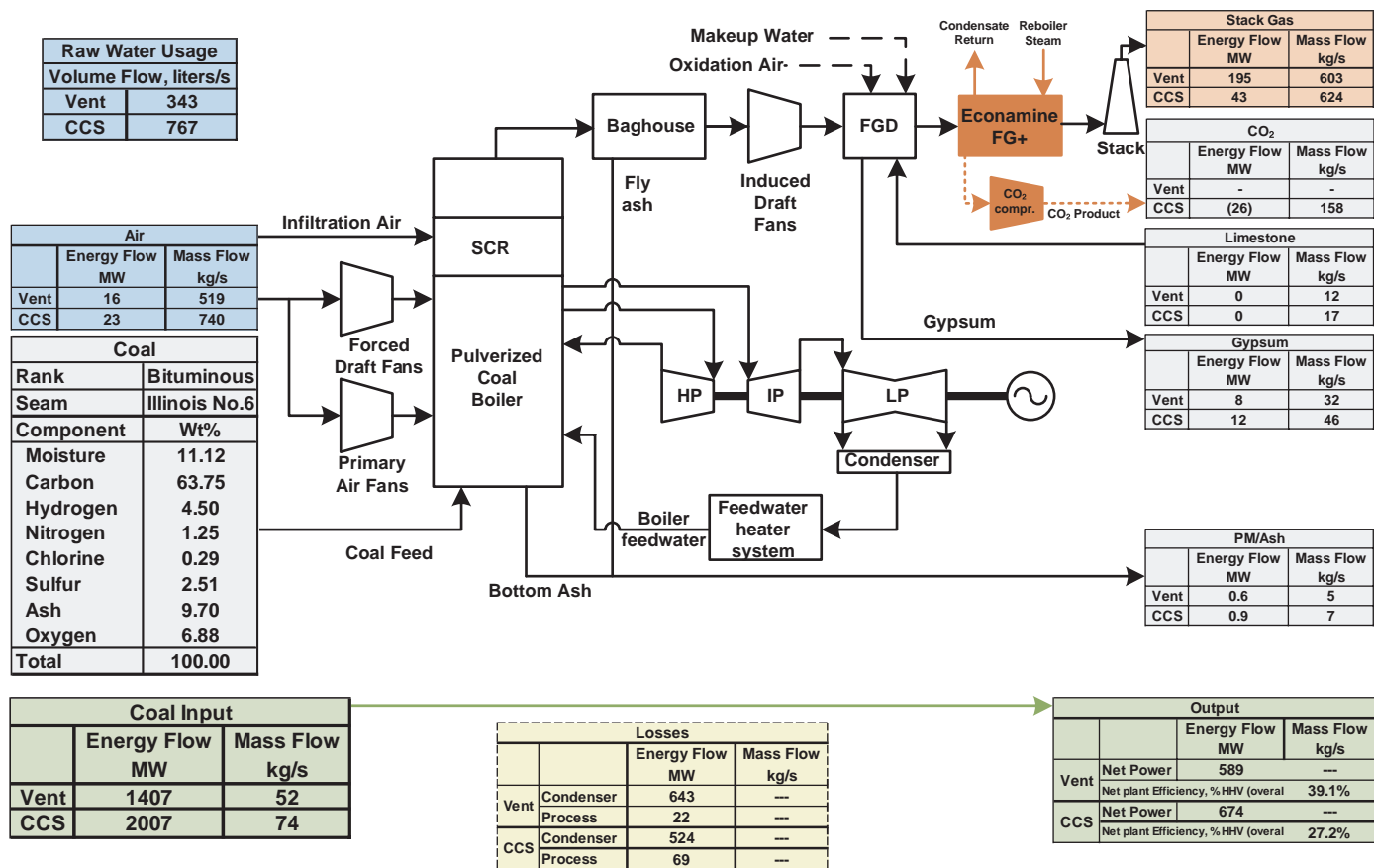
Figure 12.6 | Mass and energy balance of a typical supercritical power plant without and with carbon capture ('Vent' and 'CCS,' respectively). In the case with CCS, the net power output accounts for CO_2 compression to 153 bar, which is assumed to be sufficient to transport and inject the CO_2 into an underground storage reservoir. Source: based on Woods et al., 2007.

pressurized gasifier in which partial oxidation reactions occur, along with some water gas shift reaction. The resultant syngas, composed mainly of CO and H_2, is cooled and cleaned, including removal of essentially all particulate matter, which might otherwise create operating difficulties in downstream processes. Sulfur compounds in the syngas (primarily H_2S, with some COS (carbonyl sulfide)) are then removed, e.g., using the Selexol® physical absorption process, to ensure that air emissions limits are met. The syngas is then fed to a gas turbine designed to operate on a CO and H_2 mixture. The turbine generates power, and its high temperature exhaust passes to a heat recovery steam generator (HRSG) to generate superheated steam. The steam drives a steam turbine bottoming cycle to generate additional power.

If CO_2 is to be captured for storage, three additional steps are required (orange shading in Figure 12.7). First, the composition of the cleaned syngas is adjusted following gasification via the water gas shift reaction to primarily H_2 and CO_2. This is followed by capture of both H_2S and CO_2 in the acid gas removal step, and then by compression of the captured CO_2 to an elevated pressure for pipeline transport to a storage site for underground injection. Typically, CO_2 that would otherwise have been

emitted to the atmosphere can be reduced by 90% using these additional steps.

Several different coal gasifier designs are offered by vendors. Two key features that differentiate designs are the type of feeding system (dry coal feed or coal-water slurry feed) and the syngas cooling strategy (radiant cooling or quench cooling). Dry-feed gasifiers are able to utilize a range of coal types, including lower-rank coals (lignite, sub-bituminous). Slurry-feed gasifiers cannot utilize lower-rank coals because the oxygen requirements for reaching the high temperature needed for effective gasification become prohibitive. Dry-feed gasifiers have higher efficiencies than slurry-feed gasifiers when both are operating on bituminous coal. On the other hand, slurry-feed gasifiers can operate at considerably higher pressures than dry-feed gasifiers, which can be advantageous in some circumstances. The use of radiant syngas cooling generally provides for higher overall plant efficiency than quench cooling, but also requires greater capital investment. For IGCC-CCS systems, the efficiency advantage with radiant cooling is offset to a significant degree by the added benefit with quench cooling of saturating the syngas with moisture, which avoids the need to raise steam for injection to the water gas shift (WGS) reactor.

Table 12.6 | Performance and cost estimates for PC power plants burning bituminous coal.

CO$_2$ vented or captured/stored →	Subcritical steam cycle		Supercritical steam cycle	
	Vent	CCS	Vent	CCS
As-received coal input, t/day	4,768	7,044	4,477	6,386
Coal input, MW HHV	1,496	2,211	1,405	2,004
Coal input, MW LHV	1,427	2,108	1,340	1,911
Gross electricity production, MW	583.3	679.9	580.3	663.4
On-site power consumption, MW	32.9	130.3	30.1	117.5
Net power generation, MW	550.4	549.6	550.2	546
Net generating efficiency (% HHV)	36.8	24.9	39.2	27.2
Life cycle GHG emissions,[a] kgCO$_2$eq/MWh$_{net}$	896	187	831	171
CO$_2$ emissions, kgCO$_2$/MWh$_{net}$	855	126	792	115
SO$_2$ emissions, gSO$_2$/MWh$_{net}$	357	negligible	335	negligible
NO$_x$ emissions, gNO$_x$/MWh$_{net}$	295	436	277	398
PM emissions, gPM/MWh$_{net}$	55	81	51	74
Hg emissions, gHg/MWh$_{net}$	0.005	0.007	0.005	0.007
Installed capital cost (US siting, US$_{2007}$$)				
Total plant cost (TPC), million US$_{2007}$$	880	1,642	894	1,617
Specific TCP, US$_{2007}$$/kWnet	1,598	2,987	1,625	2,961
Levelized generating cost, US$_{2007}$$/MWhb				
Capital (at 14.38% capital charge rate)	33.1	61.8	33.6	61.3
O&M (at 4% of TPC per yr)	8.6	16.0	8.7	15.9
Coal (at 2.04 US$/GJ, HHV)	19.9	29.5	18.7	26.9
CO$_2$ transportation and storage	0	7.0	0	6.4
Levelized cost of electricity, US$_{2007}$$/MWh	61.6	114.4	61.1	110.5

a Life cycle GHG emissions include CO$_2$ emissions at the plant plus emissions (expressed as CO$_2$-eq) that occur during coal mining and transportation.

b The following assumptions, representing US financial conditions, are adopted for all levelized cost calculations: coal price (US$/GJ$_{HHV}$) is 2.04; annual operating and main-tenance (O&M) costs are 4% of total plant cost; the annual capital charge rate on TPI is 14.38%; TPI is total plant investment (TPC plus interest during construction); the capacity factor for power-only plants is 85%; the capacity factor for plants (described later) that produce liquid fuels or hydrogen (with or without coproduct electricity) is 90%. Also, costs for pipeline transportation and underground injection of compressed (150 bar) CO$_2$ are estimated based on work by Ogden, 2003; Ogden, 2004, as discussed in Liu et al., 2011a.
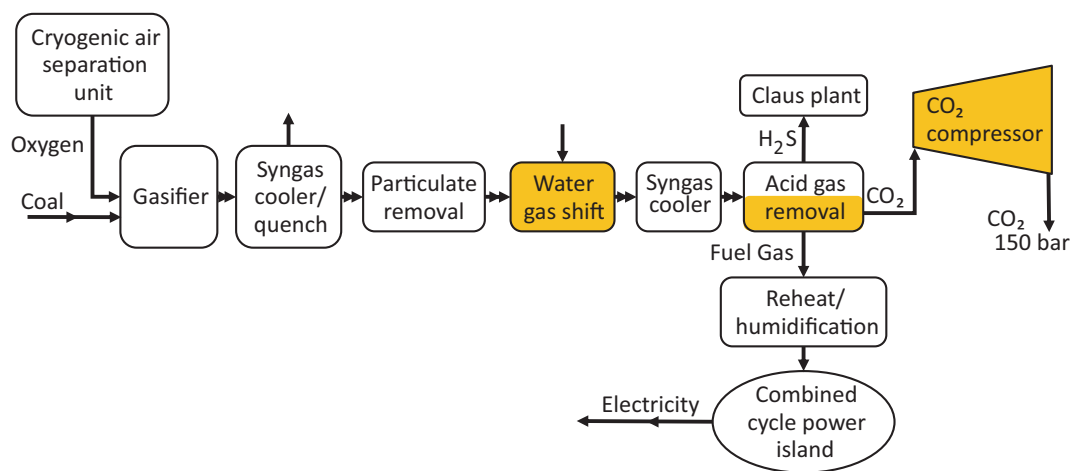
Source: Woods et al., 2007.

Figure 12.7 | Generic representation of coal-IGCC technology. Shaded blocks indicate units added for carbon capture and storage (CCS). When CCS is utilized, the acid gas removal unit is re-designed to capture CO$_2$ in addition to H$_2$S.
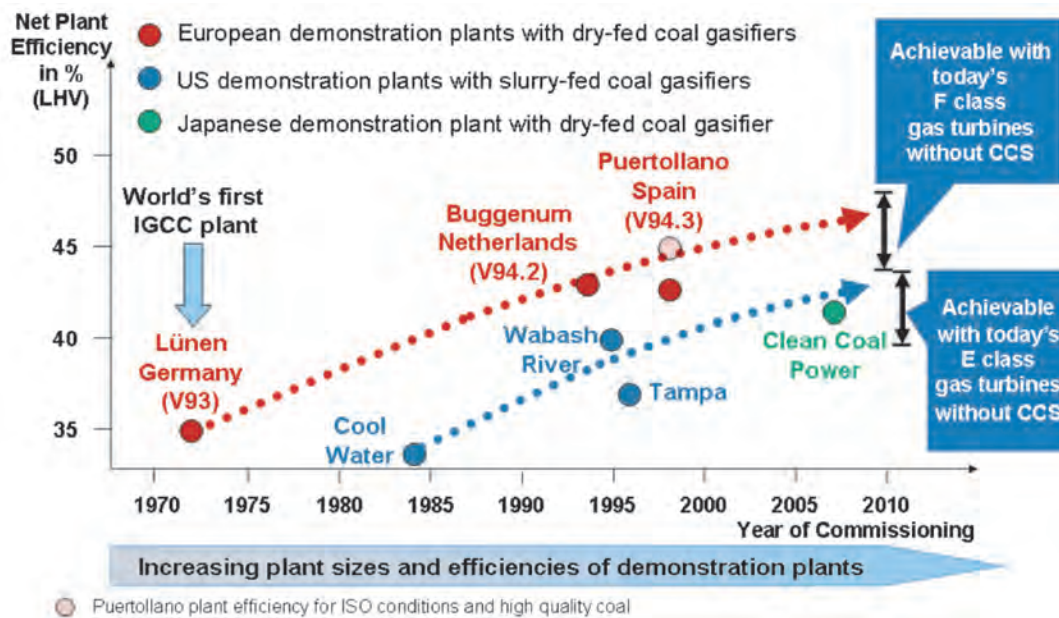
Figure 12.8 | Development of IGCC net plant efficiencies for coal-based plants without CCS. Source: Karg, 2009.

12.2.3.2 IGCC Energy and Environmental Performance

Figure 12.8 illustrates the rising trend in plant efficiencies for IGCC systems since the first plant was installed in the early 1970s. The figure also illustrates the generally higher efficiencies achievable using dry-feed gasifiers. There is a future potential for raising IGCC efficiencies through various technological means, e.g., by adapting the latest generation of gas turbines to operate on syngas, by adopting more efficient air separation technologies that are under development today, and others.

A detailed material and energy balance developed by engineers at the US National Energy Technology Laboratory (Woods et al., 2007) is shown in Figure 12.9 for a coal-IGCC system using a slurry-feed gasifier and venting CO_2 to the atmosphere. Figure 12.9 also shows a balance for a similar IGCC design, but with CO_2 capture and compression. Table 12.7 summarizes the performance of these two designs and shows estimates also from Woods et al. (2007) for two alternative IGCC designs using different gasifier technologies. With venting of CO_2, the electricity generating efficiencies for these three designs range from 38–41% (HHV basis). Capturing 90% of the generated CO_2 and compressing it for storage incurs a six to nine percentage point efficiency penalty depending on the design (or a 16–22% reduction in electricity output per unit of coal input). Emissions of conventional pollutants are low, especially SO_2 and PM, regardless of whether CO_2 is vented or captured.

Gasification-based power generation can also be utilized with biomass feedstocks. The right two columns in Table 12.7 show performance estimates for biomass-IGCC (BIGCC) systems made for this chapter by a team at the Princeton Environmental Institute (PEI) at Princeton

University. For consistency of comparisons, PEI estimates for two CIGCC systems are also shown.[6] Feedstock collection and delivery logistics for biomass use will generally limit BIGCC plant sizes. The BIGCC systems shown in Table 12.7 are designed for a biomass input capacity of about 3000 t/day dry biomass fed to a pressurized oxygen-blown fluidized-bed gasifier (such as the one originally developed at the Gas Technology Institute (GTI) in the 1980s, the license for which is now owned by Carbona).

With venting of CO_2, the BIGCC system efficiency exceeds that of a CIGCC system by several percentage points due primarily to three factors: reduced onsite electricity use for supplying oxygen (since biomass itself contains some oxygen and the gasification temperature with biomass is much lower than with coal), no requirement for sulfur removal (since most biomass has negligibly low sulfur content), and less nitrogen injection in the gas turbine for NO_x control due to the higher methane content of biomass-derived syngas (which yields lower combustion flame temperatures compared with coal-derived syngas).

A key benefit of utilizing biomass is the negative greenhouse gas emissions that can be achieved. Even with CCS, a CIGCC will still release some CO_2 to the atmosphere. When biomass is used, the CO_2 that is stored underground originated in the atmosphere, so net life cycle GHG emissions (including emissions associated with growing the biomass) are negative (Table 12.7).

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6 The Princeton CIGCC estimates, which are based on designs with slurry-feed gasification and syngas quench cooling (rather than radiant cooling), are consistent with the estimates of the National Energy Technology Laboratory, US Department of Energy.
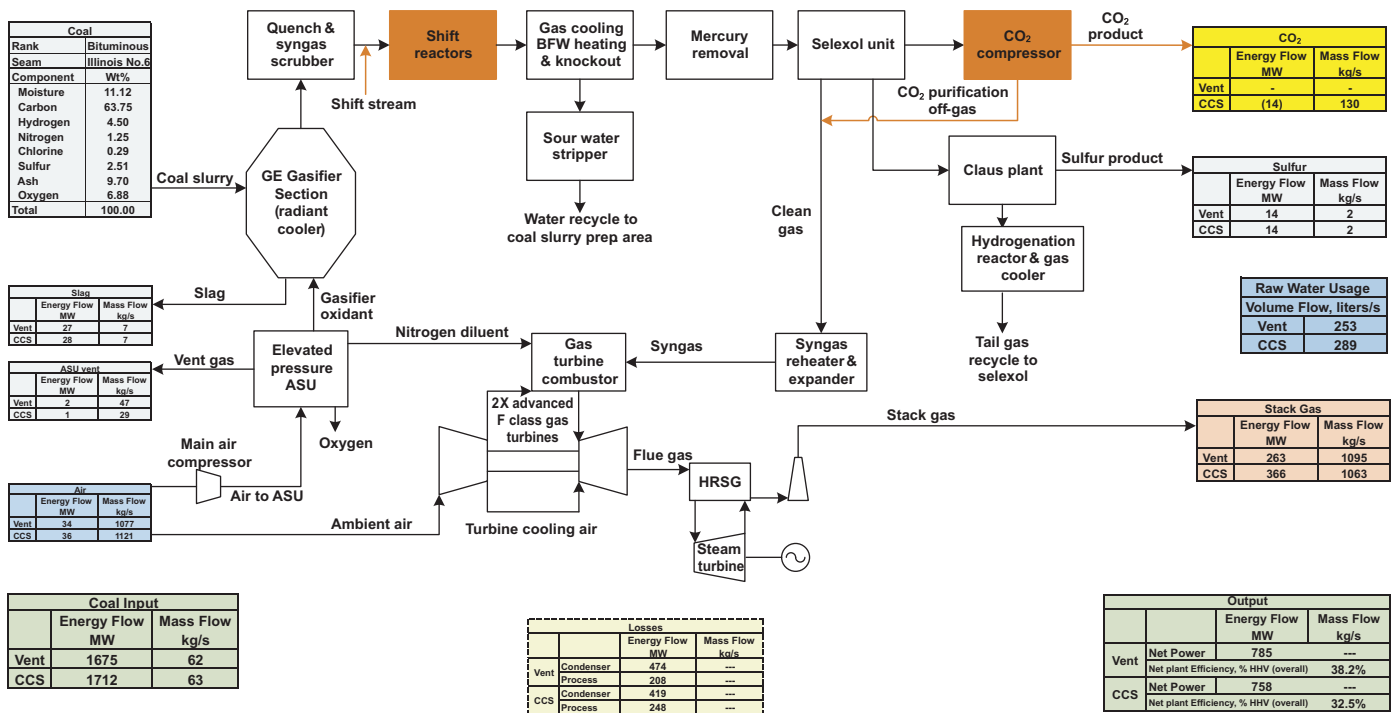
Coal	
Rank	Bituminous
Seam	Illinois No.6
Component	Wt%
Moisture	11.12
Carbon	63.75
Hydrogen	4.50
Nitrogen	1.25
Chlorine	0.29
Sulfur	2.51
Ash	9.70
Oxygen	6.88
Total	100.00

Quench & syngas scrubber → Shift reactors → Gas cooling BFW heating & knockout → Mercury removal → Selexol unit → CO_2 compressor → CO_2 product

Shift stream

GE Gasifier Section (radiant cooler)

Coal slurry

Sour water stripper

Water recycle to coal slurry prep area

CO_2 purification off-gas

CO_2	Energy Flow MW	Mass Flow kg/s
Vent	-	-
CCS	(14)	130

Claus plant — Sulfur product

Sulfur	Energy Flow MW	Mass Flow kg/s
Vent	14	2
CCS	14	2

Hydrogenation reactor & gas cooler

Raw Water Usage	Volume Flow, liters/s
Vent	253
CCS	289

Clean gas

Slag	Energy Flow MW	Mass Flow kg/s
Vent	27	7
CCS	28	7

Slag

Gasifier oxidant

Nitrogen diluent

Vent gas

ASU vent	Energy Flow MW	Mass Flow kg/s
Vent	2	47
CCS	1	29

Elevated pressure ASU

Main air compressor

Oxygen

Air to ASU

Gas turbine combustor ← Syngas

Syngas reheater & expander

Tail gas recycle to selexol

Stack Gas	Energy Flow MW	Mass Flow kg/s
Vent	263	1095
CCS	366	1063

2X advanced F class gas turbines

Flue gas

Stack gas

Air	Energy Flow MW	Mass Flow kg/s
Vent	34	1077
CCS	36	1121

Ambient air

Turbine cooling air

HRSG

Steam turbine

Coal Input	Energy Flow MW	Mass Flow kg/s
Vent	1675	62
CCS	1712	63

Losses		Energy Flow MW	Mass Flow kg/s
Vent	Condenser	474	---
	Process	208	---
CCS	Condenser	419	---
	Process	248	---

Output		Energy Flow MW	Mass Flow kg/s
Vent	Net Power	785	---
	Net plant Efficiency, % HHV (overall)	38.2%	
CCS	Net Power	758	---
	Net plant Efficiency, % HHV (overall)	32.5%	

Figure 12.9 | Mass/energy balance for a coal-IGCC plant using slurry-feed gasifier, radiant syngas cooling without and with CO_2 capture ('Vent' and 'CCS,' respectively). In the CCS case, the net power output accounts for CO_2 compression to 153 bar, which is assumed to be sufficient to transport and inject the CO_2 into an underground storage reservoir. Source: based on Woods et al., 2007.

12.2.3.3   IGCC Economic Performance

The lack of a clear cost advantage for IGCC technology is an important reason that the technology has not yet seen widespread commercial deployment, despite having been first demonstrated commercially in the 1970s. While IGCC systems have clear environmental benefits over combustion systems for coal power generation, the least costly IGCC electricity (under US conditions, Table 12.7) is not less costly than electricity from a new supercritical-steam pulverized coal (PC) plant when CO_2 capture/storage is not considered (Table 12.6).

For CIGCC systems with CCS, specific capital costs (US$/kW) increase by 30–40% compared with IGCCs that vent CO_2 (Table 12.7), with correspondingly higher levelized costs of electricity generation. But the levelized cost of electricity (LCOE) generation for a CIGCC-CCS system is considerably lower than for a PC-CCS system, because supercritical pulverized coal plants require even higher incremental capital investment for CCS and sacrifice more efficiency points in the process. As shown in Figure 12.10, the LCOE for CIGCC-CCS reaches the LCOE for a pulverized coal plant with CO_2 venting (PC-V plant) at a much lower GHG emission price (US$55/tCO$_2$-eq) compared to that for the PC-CCS plant (US$75/tCO$_2$-eq). In the BIGCC-CCS case, although the LCOE at US$0/tCO$_2$-eq is much greater than for all the other options shown, its LCOE reaches that for a PC-V plant at a still lower GHG emission price (US$42/tCO$_2$-eq) because of the strong downward slope of the LCOE curve that arises from the negative GHG emissions for this option.

12.2.4   Natural Gas Combined Cycle Technology

Natural gas-fired combined cycles are among the cleanest and most efficient fossil fuel based power generating technologies. A natural gas combined cycle (NGCC) consists of a Brayton (gas turbine) cycle, the exhaust heat from which passes through a heat recovery steam generator to raise steam for a Rankine (steam turbine) bottoming cycle. The mass and energy balance shown in Figure 12.11 is for a NGCC with an overall efficiency of 50.8% on a HHV basis. With state of the art gas turbine technologies, NGCCs can reach efficiencies up to about 55% (HHV basis).

Since the hydrogen/carbon ratio of methane is relatively high, the volumetric CO_2 concentration in the flue gas of a NGCC is low, typically about 5%. The low partial pressure of CO_2 in flue gases requires use of an amine solvent for post-combustion CO_2 capture (Figure 12.11). (See also Chapter 13.) Regenerating the solvent requires considerable energy, leading to high efficiency penalties for NGCC systems with CCS. In the example case shown in Figure 12.11, the efficiency penalty is about seven percentage points. More detailed comparison data are shown in Table 12.8.

To reduce the energy penalty for CO_2 capture, some companies are developing CO_2 recycling processes that re-circulate part of the exhaust gas back to the inlet of the gas turbine compressor, resulting in a higher CO_2 concentration in the flue gases.

Table 12.7 | Estimates for coal or biomass fueled IGCC performance and costs in US_{2007}\$.

Source of estimate>>>	US National Energy Technology Laboratory (NETL)[a]						Princeton Environmental Inst. (PEI)[b]			
Feedstock>>>	Bituminous Coal						Bituminous Coal		Switchgrass biomass	
Gasifier technology >>>	GE Energy (slurry)		Conoco-Phillips (slurry)		Shell (dry)		GEE-Quench		GTI fluid bed	
CO_2 vented or captured>>>	Vent	CCS	Vent	CCS	Vent	CCS	Vent	CCS	Vent	CCS
Coal input rate										
As-received, metric t/day	5,330	5,447	5054	5206	4927	5151	4,477	4,477	0	0
Coal, MW HHV	1673	1709	1586	1634	1546	1616	1,405	1,405	0	0
Biomass input rate										
As-received, metric t/day	0	0	0	0	0	0	0	0	3,792	3,792
Biomass, MW HHV	0	0	0	0	0	0	0	0	699	699
Electricity output										
Gross production, MW	770	745	743	694	748	694	594	582	348	306
On-site consumption, MW	130	189	119	176	112	176	67	146	31	47
Net exports, MW	640	556	623	518	636	517	528	435	317	259
Efficiency (HHV)	38.3%	32.5%	39.3%	31.7%	41.1%	32.0%	37.5%	31.0%	45.3%	37.0%
Pollutants, grams per MWh										
SO_2	51.4	45.7	49.1	41.7	39.4	50.9	not estimated			
NO_x	222	223	234	243	220	236				
Particulate matter	28.9	34.1	28.1	34.6	26.7	34.7				
Carbon dioxide										
CO_2 vented, tonne/hr	508	51	489	60	477	46	418	34	224	15
CO_2 stored, tonne/hr	0	469	0	444	0	453	0	385	0	209
LC GHG emis., kgCO$_2$eq/ MWh	833	138	823	162	787	136	833	126	25	-776
Economics and metrics[c]										
Total plant cost (TPC), $10^6 US_{2007}$\$	1194	1370	1115	1300	1320	1424	1003	1166	636	720
Specific TCP, US_{2007}\$/kWe	1865	2466	1788	2508	2076	2755	1901	2677	2008	2779
Levelized cost of electricity (US_{2007}\$/MWh)[c]										
Capital (at 14.38% of TPI)	38.6	51	37.2	51.9	43.0	57.0	39.3	55.4	41.6	57.5
O&M (at 4% of TPC per yr)	10	13.2	9.6	13.5	11.2	14.8	10.2	14.4	10.8	14.9
Coal (at 2.04 US\$/GJ, HHV)	19.1	22.5	18.6	23.1	17.8	22.9	19.5	23.6	0	0
Biomass(at 5 US\$/GJ, HHV)	0	0	0	0	0	0	0	0	39.7	48.6
CO_2 transportation & storage	0	5.6	0	5.9	0	5.9	0.0	6.2	0.0	7.6
Cost of electricity, US2007\$/MWh	**68**	**92**	**65**	**94**	**72**	**101**	**69**	**100**	**92**	**129**

a Performance and capital costs from Woods et al., 2007. Capital costs escalated to January-mid US_{2007}\$ costs using the ratio of the 2007 average chemical engineering plant cost index to the January 2007 value (1.03). Levelized electricity costs calculated assuming financing parameters described in note (c) below.

b These are previously unpublished estimates that have been made for this chapter using the methodology and assumptions consistent with the work of Liu et al., 2011a. For cases utilizing biomass, the moisture content of the delivered biomass is 15%. No separate biomass drying step is included.

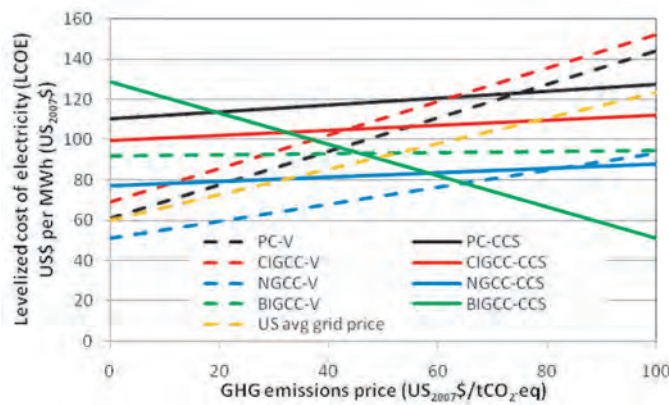c See note (b) of Table 12.6 for financial parameter assumptions.

Figure 12.10 | Estimated levelized cost of electricity generation (LCOE) for alternative technologies as a function of GHG emissions price. (See Table 12.6, Table 12.7, and Table 12.8 for detailed cost assumptions.) The CIGCC and BIGCC systems shown here correspond to the PEI performance and cost estimates shown in Table 12.7.) Also shown is the 2007 average price paid to electricity generators in the United States (at zero GHG price) and how this price would change with GHG emissions price if the emissions are assumed to be the US grid-average for 2007 (636 kgCO$_2$-eq/MWh).

The minimum GHG emissions price needed to motivate adding CCS to a NGCC plant (US$83/tCO$_2$-eq) is even higher than for a PC plant, as a result of the much lower concentration of CO$_2$ in the flue gas and the smaller amount of CO$_2$ emitted per kWh of electricity. However, for the assumed fuel prices in Figure 12.10, the LCOE for NGCC-CCS at this GHG emissions price is lower than for any of the coal options considered.

12.2.5   Health Damage Costs of Power Plants

Air pollution (especially SO$_x$, NO$_x$, and particulate matter) from fossil fuel power generation imposes public health costs that are not reflected in power generating costs discussed to this point in this chapter. The health damage costs vary with the power generating fuel and technology, as well as with income level and demographics of the exposed populations (NRC, 2010). There are inherent and large uncertainties in estimating health damage costs, but a preponderance of published studies suggests that costs are significant in many cases, especially with coal-fired power generation
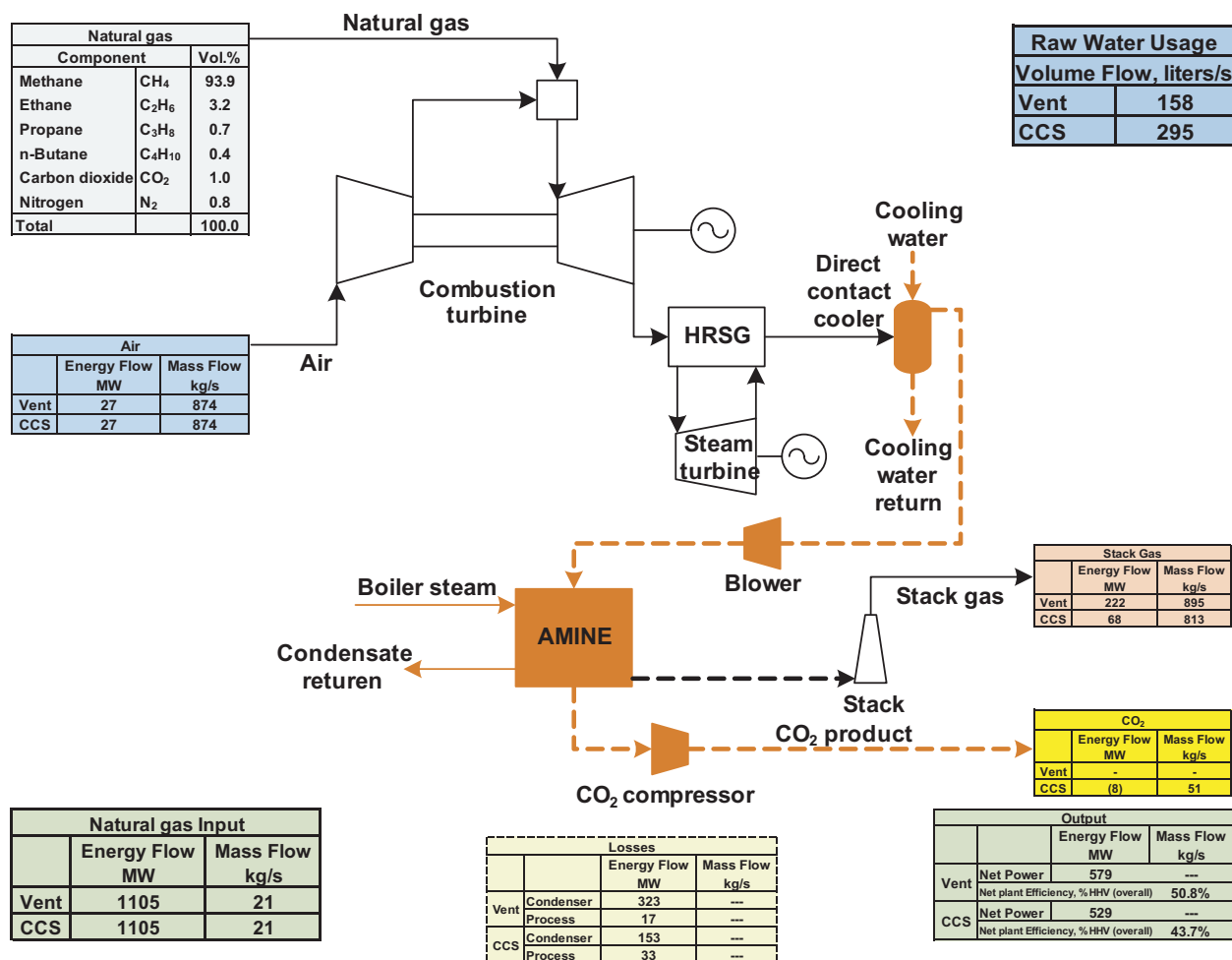

Figure 12.11 | Mass and energy balance of NGCC without CO$_2$ capture (when shaded components are excluded). Including shaded components, the schematic represents NGCC with post-combustion CO$_2$ capture. For the case with CCS, the net power output accounts for CO$_2$ compression to 153 bar, which is assumed to be sufficient to transport and inject the CO$_2$ into an underground storage reservoir. Source: based on Woods et al., 2007.

Table 12.8 | NGCC cost, performance, and environmental profile.

Advanced "F Class" gas turbine	NGCC (NETL)	
CO₂ vented or captured→	V	CCS
Natural gas input rate		
t/day	1,798	1,798
HHV, MW	1,102	1,102
Electricity output		
Gross production, MW	570.2	520.1
On-site consumption, MW	9.8	38.2
Net exports, MW	560.4	481.9
Efficiency (HHV)	50.8%	43.7%
Pollutants, grams/ MWh$_{net}$		
SO₂	-	-
NOₓ	27.7	32.3
Carbon dioxide		
CO₂ vented, t/hr	203.3	20.3
CO₂ stored, t/hr	0.0	183.0
LC GHG emis., kg CO₂-eq/MWh$_{net}$	420.8	109.6
Capital costs		
Total plant cost (TPC), million US$_{2007}$$	321	583
Specific TCP, US$_{2007}$$/kWe	572	1,209
Levelized cost of electricity (US$_{2007}$$/MWh)^a		
Installed capital (at 14.38% of TPI)	11.8	25.0
O&M (at 4% of TPC per yr)	3.1	6.5
NG (at US$5.11/GJ$_{HHV}$)	36.2	42.1
CO₂ transportation and storage	0.0	3.5
Total cost of electricity, US2007$/MWh	51.1	77.1

a See note (b) of Table 12.6 for financial parameter assumptions.

Source: Woods et al., 2007.

located near population centers. We discuss here estimates of costs of damages due to air pollution in the United States, China, and Europe.

The environmental and cost impacts of air-pollution control strategies are explicitly considered in the future-pathways analysis presented in Chapter 17. Details of the pollutant emissions projections are discussed in Section 17.5.2, and Section 17.7 concludes that stringent policies for climate mitigation to decarbonize the energy system may bring the co-benefit of reducing air pollution control costs by up to 75% globally, with attendant reductions in health impacts and related damage costs of the type we discuss here. Also Chapter 4 addresses the interaction of energy and health in detail.

12.2.5.1   United States

Since publication of the pioneering Harvard School of Public Health study (Pope III et al., 1995), it has been known that the most significant

health hazards from air pollution are associated with small "PM$_{2.5}$" particles (particulate matter with particle diameters less than 2.5 microns). Inhaled, these small particles become lodged in and build up in the alveoli of the lungs and give rise to significant life-shortening. PM$_{2.5}$ particles are emitted directly by power plants and other combustion systems and also formed in the atmosphere from gaseous primary emissions of SO₂ and NOₓ.

One study (Abt Associates Inc., 2000) estimated that over 30,000 premature deaths each year were attributable to fine particle pollution from power plants near the turn of the century in the United States. An analysis by the United States Environmental Protection Agency (US EPA, 1997) estimated an average life-shortening of 14 years for a person dying prematurely as a result of exposure to fine particle air pollution in the United States.

A recent Harvard School of Public Health study (Levy et al., 2009) has systematically assessed the public health damage costs for air pollution from 407 coal power plants in the United States that account for over 90% of US power plant SO₂ and direct PM$_{2.5}$ emissions and over 80% of NOₓ emissions. The most significant health damages are the result of premature deaths arising from PM$_{2.5}$ air pollution. The authors of this report estimated median costs of emissions (US$/tonne) based on estimated dollar values of the health damages, as well as values at the 5[th] and 95[th] percentiles for uncertainty. In the left-most column in Table 12.9, the median estimates of health damages (US$/tonne) from this study[7] are applied to average emission rates for US existing coal power plants in 2007. This table shows that SO₂ emissions account for over 70% of the total health damage costs.

At the median level of health damage cost estimates, the specific cost of health damages (US$87/MWh) is 2.5 times the direct cost of electricity from a fully-depreciated coal plant (US$35/MWh).[8] At the 5th and 95th percentiles of uncertainty (see Table 12.9, note d) the public health damage costs would amount to 1.3 times and 4.5 times the private cost of generation for written-off plants.

Coal power plant owners would like to keep old written-off units running as long as possible because they are so profitable – the average US selling price for electricity is about twice the generation cost for a written-off plant. However, these plants are profitable only in terms of private costs – not total societal costs. Taking into account

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7   Another major study for the United States (NRC, 2010) that used a similar methodology as Levy et al. (2009) found considerably lower damage costs, highlighting the inherent uncertainties involved in externality costing. Nevertheless, the two studies can be reconciled largely by the fact that the National Research Council study uses a concentration-response function for premature mortality based on Pope et al. (2002), rather than on the more recent work by Schwartz et al. (2008).

8   This is based on average conditions for US coal power plants in 2009: HHV efficiency of 32.6% and an average coal price for power generators of $2.08/GJ (EIA, 2010b) and an operation and maintenance cost of $11.93/MWh for existing coal power plants as estimated in Simbeck and Roekpooritat (2009).

Table 12.9 | Estimated health damage costs (US$_{2007}$$) from air pollution for alternative power plants.

	US average coal plant (2009)[a]	Subcritical PC[b]		Supercritical PC[b]		CIGCC[b]		NGCC[b]		XTL-OT-CCS[c]
		Vent	CCS	Vent	CCS	Vent	CCS	Vent	CCS	
Emission rates, kg/MWh										
SO_2	2.97	0.357	0.0	0.335	0.0	0.051	0.046	0.0	0.0	0.0
NO_x	1.70	0.295	0.436	0.277	0.398	0.222	0.223	0.028	0.032	0.164
$PM_{2.5}$	0.196	0.034	0.050	0.032	0.046	0.018	0.021	0.0	0.0	0.016
Health damage costs[d], US$_{2007}$$ MWh										
SO_2	62.2	7.5	0.0	7.0	0.0	1.1	1.0	0.0	0.0	0.0
NO_x	9.0	1.6	2.3	1.5	2.1	1.2	1.2	0.2	0.2	0.9
$PM_{2.5}$	15.6	2.7	4.0	2.5	3.6	1.4	1.7	0	0	1.2
Total	87	12	6.3	11	5.7	3.7	3.8	0.2	0.2	2.1
Total relative to average US electricity generation price in 2009	149%	20.1%	10.8%	18.9%	9.8%	6.3%	6.5%	0.3%	0.3%	3.6%
HHV efficiency of power plant	32.6%	36.8%	24.9%	39.2%	27.2%	38.3%	32.5%	50.8%	43.7%	–

a   In 2009 total emissions of SO_2 and NO_x from coal power plants in the US power sector were 5.19 and 1.81 Mt, respectively (US EIA, 2010a) when generation from coal in the power sector totaled 1749 million MWh. For $PM_{2.5}$ it is assumed that in 2009 the $PM_{2.5}$ emission rate is based on the median 1999 estimate of 0.0413 lb per million BTU (17.8 gm/GJ) of coal input for the 407 coal plants investigated in Levy et al. (2009).

b   Emission rates for SO_2, NO_x, and PM from these new plants are from Woods et al. (2007). For PC plants the emission rates are based on BACT (best available control technologies), exceeding NPPS (new source performance standards) requirements. For CIGCC plants, the emission rates are based on the Electric Power Research Institute's Coal Fleet User Design Basis Specification. $PM_{2.5}$ emissions are assumed to be 0.62 x PM emissions, following Dockery and Pope (1994).

c   For XTL-OT-CCS plants emission rates for NO_x and $PM_{2.5}$ are assumed to be the same per MWh of gross gas turbine output as for CIGCC-CCS plants, but the SO_2 emission rate is assumed to be zero because protecting synthesis catalysts requires reducing the sulfurous compounds in syngas essentially to zero.

d   For 407 US coal power plants (which accounted in 1999 for over 90% of US power plant emissions of SO_2 and $PM_{2.5}$ and over 80% of US power plant emissions of NO_x) median estimates of health damage costs were found to be US$20.9, US$5.3, and US$79.3 per kg for SO_2, NO_x, and $PM_{2.5}$, respectively, in 1999 (Levy et al., 2009). These valuations were assumed for all the alternative power plants in this table. At the 5th and 95th percentiles for uncertainty, the damage costs (in US$_{2007}$$) were estimated to be, respectively, US$11.0 and US$35.3 per kg for SO_2, US$2.0 and US$9.4 per kg for NO_x, and US$45.2 and US$198.4/kg for $PM_{2.5}$. At the 5th and 95th percentiles for uncertainty, total health damage costs for US coal-fired power plants are US$45.0/MWh and US$159.5/MWh, respectively.

health damages from air pollution and considering the low estimate of health damage costs presented in Table 12.9 (5th percentile of uncertainty (see Table 12.9, note d)) the total cost of generation (private cost for a written-off plant + air pollution damage cost) would be 37% higher than the US average electricity generation price in 2009 (US$58/MWh). This is the case without any cost assigned to greenhouse gas emissions.

Estimates of health damage costs from air pollution are also indicated for alternative new power plants in Table 12.9, based on emission rate estimates from Tables 12.7 and 12.8. This table shows that damage costs are extremely low for NGCC plants, still significant for new subcritical or supercritical PC-V plants, but quite low for all the plants with CCS. The XTL-CCS plants in the table refer to plants that co-produce electricity and Fischer-Tropsch Liquids (FTL) transportation fuels from X, where X is coal, biomass, or coal+biomass (as will be described in detail in later sections of this chapter). The XTL-CCS plants are characterized by damage costs that are half or less than the damage costs for all the coal stand-alone power plants with CCS. The emission for the PC-CCS plants are low because the SO_2 level in the flue gas has to be reduced to extremely low levels upstream of the

amine scrubber to prevent amine solvent degradation. Similarly, in the XTL-CCS case, protecting downstream process catalysts requires removal of sulfur.

12.2.5.2   China

Studies of health damage costs due to air pollution are more limited for China, and studies specific to pollution from electric power generation are even scarcer. Studies that have estimated public health costs of air pollution in China include those published by the World Bank (World Bank, 1997; World Bank and SEPA, 2007) and jointly by Harvard and Tsinghua Universities (Ho and Nielsen, 2007; Ho and Jorgenson, 2008).

The Harvard/Tsinghua study (Ho and Jorgenson, 2008) is the only one that has attempted to estimate health damage costs due to power generation in China. It estimated total air pollution damage costs (from all activities) in China using a willingness-to-pay approach (Hammitt and Zhou, 2006). The estimated total cost of premature deaths, chronic bronchitis, and asthma attacks was RMB$_{2002}$213 billion, or about

Table **12.10** | Estimated health damage costs in billion RMB$_{2003}$ (billion US$)[a] due to urban outdoor air pollution in China in 2003 (WB and SEPA, 2007).

	Excess deaths	Chronic bronchitis	Direct hospital costs	Indirect hospital costs	Total	% GDP
Adjusted human capital approach						
95th percentile	178.7 (25.5)	47.7 (6.8)	4.82 (0.69)	0.670 (0.096)	231.8 (33.1)	1.8
Average	110.9 (15.8)	42.5 (6.1)	3.41 (0.49)	0.470 (0.067)	157.3 (22.5)	1.2
5th percentile	35.8 (5.1)	36.9 (5.3)	1.88 (0.27)	0.264 (0.038)	74.9 (10.7)	0.57
Willingness-to-pay approach						
95th percentile	641.1 (91.6)	136.7 (19.5)	4.82 (0.69)	0.670 (0.096)	783.3 (111.9)	4.9
Average	394.0 (56.3)	122.1 (17.4)	3.41 (0.49)	0.470 (0.067)	519.9 (74.3)	3.3
5th percentile	135.6 (19.4)	106.2 (15.2)	1.88 (0.27)	0.264 (0.038)	243.9 (34.8)	1.6

a   Estimated costs in 2003 Yuan RMB have been converted to US$ using a nominal exchange rate of 7 RMB/US$.

US$30 billion at a nominal exchange rate of 7 RMB/US$. The study also estimated that 28% of the total damage cost, or about RMB60 billion (US$8.6 billion), was attributable to electric power generation. Assuming that most of the health damage was due to coal-fired generation, which accounted for about 81% of power generated in 2002 (1338 TWh) (National Bureau of Statistics China, 2007), the estimated health damage cost was about RMB0.044/kWh (US$0.006/kWh) of coal fired generation.

The Harvard/Tsinghua estimate of total health damage cost due to air pollution is on the low end of costs estimated in the joint study by the World Bank and China State Environmental Protection Administration. That study found the average health damage costs in 2003 to be equivalent to 1.2–3.3% of GDP (RMB157–520 billion, or US$23–76 billion, assuming 7 RMB/US$). The low estimate was based on a human-capital estimation approach and the high figure was based on a willingness-to-pay approach. Uncertainty ranges in the damage costs were also estimated (Table 12.10). If 28% of total damage costs are attributed to electric power generation (as indicated by the Harvard/Tsinghua study), and coal power generation is assumed to contribute most of these damages, then the range of damage costs per kWh of coal-fired power (1580 TWh in 2003) based on Table 12.10 is RMB0.047–0.14 / kWh (US$0.007–0.02/kWh).[9]

Taken together, the World Bank/SEPA and the Harvard/Tsinghua studies suggest that health damage costs from electric power generation in the middle of this decade were equivalent to between 10–40% of the cost of new coal power generation in China today. This is far lower than damage costs estimated for the United States, and is explained in part by the large difference in per capita income between the two

countries, which reduces individuals' willingness to pay to avoid health damages, as well as lower medical costs in China and fewer health impacts being included in the damage estimates for China as compared to the US estimates (US-China Joint Economic Research Group, 2007).

As per capita incomes rise in China, the willingness to pay to avoid health damages will rise proportionately; China's GDP is expected to more than quadruple between 2005 and 2030 (IEA, 2007). At the same time coal power generation is expected to increase substantially, and pollution controls are expected to tighten significantly in this period. Also, the geographical distribution of population in relation to power plants may be significantly different in 2030 from that at present. Studies taking into account trends for these several factors are needed to understand better prospective health damage costs per MWh of coal power generation in the 2030 time frame.

12.2.5.3   Europe

The ExternE Study in Europe was carried out over a period of more than 15 years beginning in the early 1990s. It involved a comprehensive and detailed assessment of air pollution and global warming damage costs from the lifecycle of energy use in Europe, estimated on the basis of the principle of willingness to pay to avoid damages (Rabl and Spadaro, 2000; Friedrich, 2005). Estimates were published in the late 1990s for 14 countries (CIEMAT, 1999) and additional estimates were published in 2004 for three countries in Eastern Europe (Melichar et al., 2004a). The estimates correspond to the technologies and demographics in these countries in the mid-to-late 1990s. A reassessment of damage costs today would yield different results, but it is difficult to guess whether damage costs would be lower, due to improved pollution controls, or higher, due to higher population densities and higher per capita incomes. (The latter translates into higher levels of willingness to pay to avoid damages.)

The original ExternE estimates indicate that health damage costs from conventional power generation in Europe are not inconsequential. Table 12.11

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9   Another study, involving some of the same authors as the Harvard/Tsinghua study, estimated health damage costs from SO_2 emissions in the power sector to be RMB6555/t (US-China Joint Economic Research Group, 2007). The average SO_2 emissions rate from coal-fired power plants in China in 2005 was 5.4 g/kWh (based on total SO_2 emission from power sector of 11.12 million tonnes (Gao et al., 2009) and 2,047 TWh of thermal power generation (National Bureau of Statistics China, 2007). This gives a much higher damage cost estimate of RMB0.36/kWh (US$0.051/kWh using a nominal exchange rate of 7 RMB/US$).

Table 12.11 | Estimated health damage costs of power generation in 17 European countries, as of mid/late 1990s.

Country[a]	Health damage costs (US$_{2007}$ per MWh)							
	COAL				NATURAL GAS			
	Power Plant Emissions		Other fuel cycle	Total	Power Plant Emissions		Other fuel cycle	Total
	Mortality	Morbidity			Mortality	Morbidity		
Austria					2	1	0	3
Belgium	25	4	0	29				
Czech Rep.[b]	9	4	5	17				
Finland	3	1	1	5				
France	65	13	0	79	15	3	0	18
Germany	17	2	2	21	4	1	2	7
Greece					3	1	0	4
Holland	11	2	0	13	3	1	0	4
Hungary[b]	76	37	1	114	6	3	0	9
Ireland	47	9	0	57				
Italy					9	2	0	11
Norway					0	0	0	0
Poland[b]	30	19	6	56				
Portugal	26	5	11	42	0	0	0	1
Spain	35	6	1	42	5	1	0	6
Sweden	1	0	2	3				
UK	32	6	0	38	4	1	0	5

a Except for Czech Republic, Hungary, and Poland, original estimates given by CIEMAT, 1999 in 1995 ECU/MWh have been converted to US$_{2007}$/MWh by assuming 1.25 US$/ECU and using the ratio of 2007:1995 US GDP deflators (1.3).

b Original estimates given by Melichar et al., 2004b in 2002 Euro/MWh have been converted to US$_{2007}$/MWh by assuming 1.25 US$/Euro and using the ratio of 2007:2002 US GDP deflators (1.15).

shows these estimates by country for coal and for natural gas-fired power generation. Damages with coal are considerably higher than with natural gas. Also, there is a wide range in estimates for coal-fired generation damages from one country to another. Costs in Finland and Sweden are under US$5/MWh, most likely reflecting the low density of populated areas, the high level of pollution control technologies, and the modest amount of coal-fired power generation in these countries. The majority of countries in Western Europe have damage costs in the range of US$40–80/MWh – comparable to the cost of electricity production for a new coal-fired power plant. At the extreme high end is Hungary at US$114/MWh.

12.3 Technological Changes at Refineries and Opportunities for CCS

12.3.1 Context

12.3.1.1 Demand for Liquid Fuels

Liquid fuels are the world's single largest source of energy and are expected by many to remain so for decades to come. The United States

Energy Information Administration (US EIA) (2010b) forecasts an increase in world liquid fuel consumption from 86 million bbl/day in 2007 (192 EJ/yr) to 111 million bbl/day in 2035 (248 EJ/yr) (Figure 12.12). The US EIA projects this increase to occur primarily in non-OECD Asia (a 93% increase for that region), followed by Central and South America, and the Middle East. Liquid fuel share of world energy use drops from 35% in 2007 to 30% in 2035, still remaining the single largest global source of energy. The vast majority of these liquids (96% in 2007 and 80–91% projected for 2035) are from conventional petroleum, with the rest coming from unconventional sources, including heavy oil and tar-sand bitumen (processed in refineries and tar sand upgraders), biofuels, coal-to-liquids and gas-to-liquids plants (Figure 12.13). Biofuels, such as renewable diesel, may be coprocessed in oil refineries but are unlikely to amount to more than 1% of total refinery throughput by 2035. Transportation accounted for nearly half of all liquid consumption in 2007, with industry accounting for about a third. The transportation fraction is projected to reach 60% by 2035, with industry falling to 29% (Figure 12.14).

These projections are consistent with trends over the past decade. From 1998 to 2008, petroleum consumption grew by 15%, with Central and
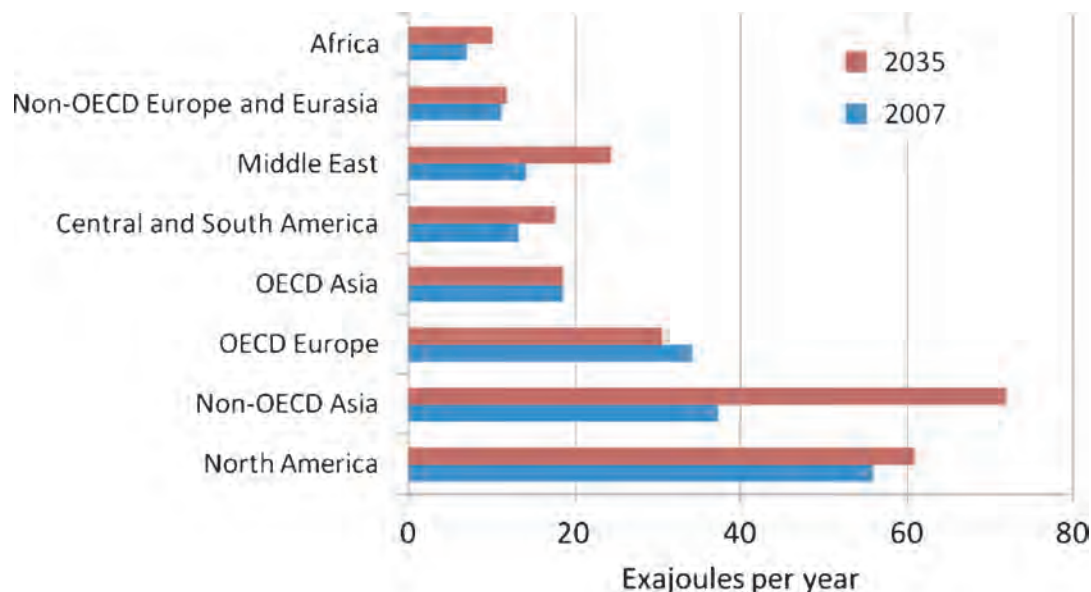
Figure 12.12 | World liquids consumption by region. Source: based on US EIA, 2010a.

South America, China, India, and the Middle East accounting for 72% of the increase (BP, 2009). The US EIA projection is also largely consistent with projections in *The Outlook for Energy: A View to 2030* (ExxonMobil, 2009). ExxonMobil has forecast world liquid fuel demand of 108 million bbl/day by 2030 (241 EJ/yr), with transportation fuel demand of 62 million bbl/day (138 EJ/yr). They expect 94% of the latter demand to be met from oil, 5% from biofuels, and 1% from natural gas. In this *Outlook*, US demand for transportation fuels peaks around 2015 and declines by 10% to 13 million bbl/day by 2030 (29 EJ/yr), the European Union demand stays flat at about 9 million bbl/day (20 EJ/yr), and China's demand triples to 8 million bbl/day (18 EJ/yr).

The IEA (2009a) forecasts global oil demand of 105 million bbl/day in 2030 (234 EJ/yr) with 97% of the increase from transportation fuels and all growth in the non-OECD countries. Their 450 Scenario (an aggressive timetable of actions to limit atmospheric greenhouse gas concentration to 450 ppm CO_2-eq) projects oil demand lower by 12 million bbl/day (27 EJ/yr), but still higher than current demand.

Forecasts of biofuel use are in the range of 3–6 million bbl/day by 2030 (6.7–13 EJ/yr). ExxonMobil expects about 3 million bbl/day (6.7 EJ/yr) with 30% from US corn ethanol, 30% from Brazil sugar cane and the remaining from biodiesel worldwide. The US EIA (2009b) forecasts 5.9 million bbl/day (13 EJ/yr), assuming that cellulosic technology will be significant from 2012.

12.3.1.2   Crude Oil Supply

World oil reserves have increased steadily over the past several decades, despite periodic predictions to the contrary. They have increased from

998 billion barrels (bbl) in 1988 (6088 EJ) to 1069 billion bbl in 1998 (6521 EJ) to 1258 billion bbl (7674 EJ) at the end of 2008 (BP, 2009). Current proven reserves are sufficient for the next 40 years and it is widely assumed that additional reserves are yet to be discovered. (See Chapter 7 for additional discussion of oil reserves.) There is a significant mismatch, however, between the location of reserves and the centers of demand for liquid fuels. This mismatch is likely to become more pronounced. For example, regions where 75% of fuel demand is located hold only 9.5% of the current reserves (Table 12.12). The extensive need to import crude oil that major fuel consuming countries face will continue, with its concomitant supply security concerns. It should be noted, however, that, since the first short oil embargo and the Iranian revolution in the mid- and late seventies, and despite several wars and conflicts in oil-producing regions, there has been no world supply disruption that would justify uneconomic or environmentally unsound measures and investment for the sake of "security." Indeed, the world's fastest-growing oil importer, China, has successfully embarked on a course of securing supplies all over the world through alliances and outright acquisition of reserves.

Crude oil is primarily categorized and priced by its gravity and sulfur content with heavier, more sour crudes being the cheapest and most difficult to process into usable, lighter fuels. About 20% of world reserves are classified as "sweet," i.e., light, low sulfur crudes, 65% are "light or medium sour," and 15% "heavy sour." This mix will change slowly over the next couple of decades, probably with more sour and heavy sour crudes in production. Any new refining capacity being built now will readily accommodate anticipated crude mix changes.

Estimates for reserves of heavy and extra heavy oil, bitumen from oil sands, and shale oil vary depending on technology and economic

feasibility assumptions but are generally considered to be approximately 3735 EJ and resources in place to be approximately 56,000 EJ (Table 7.8), with only a minor fraction produced to date.

12.3.1.3   Oil Refining Capacity

Global refining capacity (Table 12.13) increased by 11% in the last decade with 69% of the increase occurring in China, India and the Middle East and 15% in the United States. These numbers do not include the new 580,000 BD refinery added to the Reliance complex at Jamnagar (India) that started up in 2009 and makes Jamnagar one of the largest and most modern refinery sites in the world. Nor do the numbers include the 240,000 BD Fujian refinery expansion that also started in 2009 in China. Future capacity additions will generally follow the liquid
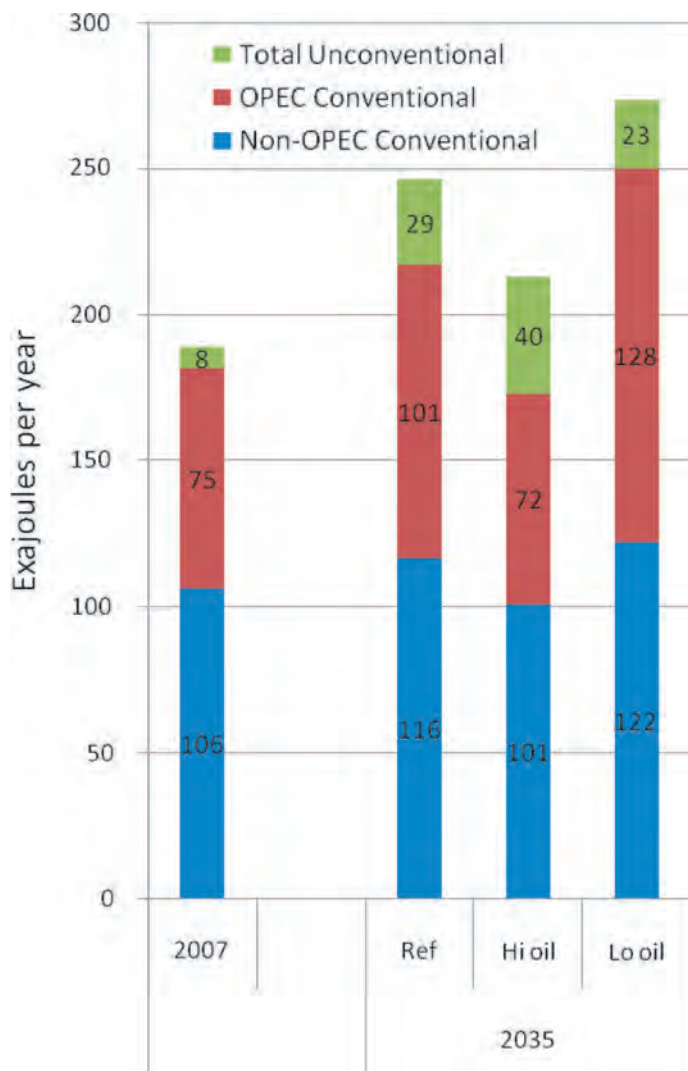
Figure 12.13 | Projections of world liquids supply in 2035 for three alternative oil price projections. Source: based on US EIA, 2010a.
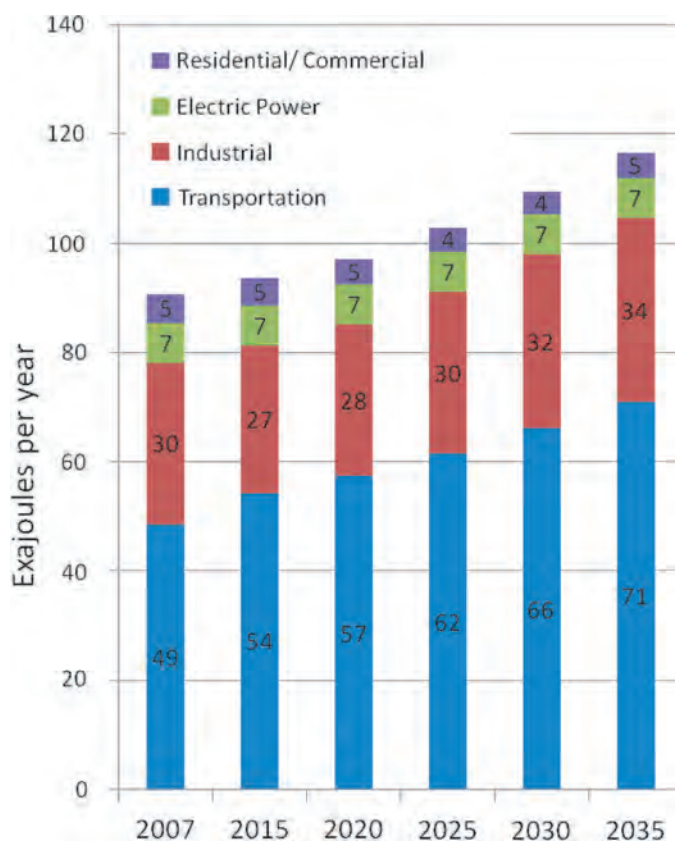
Figure 12.14 | Projections of world liquids consumption by sector. Source: based on US EIA, 2010a.

Table 12.12 | Oil reserves and consumption by region in 2008.

	Reserves 10⁹ bbl (EJ)	Consumption 10³ bbl/d (EJ/yr)	% of Reserves	% of Consumption
World	1,258 (7,674)	84,455 (188)	100	100
United States	30.5 (186)	19,419 (43)	2.4	23.0
European Union	6.3 (38.4)	14,765 (33)	0.5	17.5
China	15.5 (94.6)	7,999 (18)	1.2	9.5
Middle East	754 (4,599)	6,423 (14)	59.9	7.6
Asia Pacific (incl.China)	42 (256)	25,339 (57)	3.3	30.0
North America (incl.US)	70.9 (432)	23,753 (53)	5.6	28.1
N. Am., Asia Pac., & EU	119.2 (727)	63,857 (142)	9.5	75.6

Source: BP, 2009.

Table 12.13 | Refining capacity 1988–2008, 10³ bbl/day.

	1998	2008	Capacity increase	% increase	% of world capacity increase
World	79,699	88,627	8,928	11	100
United States	16,261	17,621	1,360	8.4	15
European Union	15,262	15,788	526	3.4	6
Central and South America	6,114	6,588	474	7.8	5
Middle East	6,202	7,592	1,390	22	16
China	4,592	7,732	3,140	68	35
India	1,356	2,992	1,636	121	18

Source: BP, 2009.

fuels demand with most new capacity expected in non-OECD Asia. In the United States and the European Union, some capacity will be shut down for economic reasons (e.g., in 2010 Valero announced the permanent shutdown of its Delaware refinery, or 7% of its capacity, and BP announced plans to sell its Texas City, Texas, and Carson, California, refineries) while some revamps and expansions will occur in the United States for processing heavy Canadian crude. China is expected to add around 3 million bbl/day of capacity by 2015 while shutting some of the smaller, less efficient refineries that have a combined capacity of between 1 million bbl/day and 1.5 million bbl/day.

12.3.2   Refining Technology and Economics

Refineries are complex processing plants that can generally handle a wide range of crude oil feedstocks and produce hundreds of products of varying specifications. No two refineries are alike. Each one has been designed for a particular market and presumed crude slate and then modified over time as product specifications, environmental regulations, and crude supply economics evolve. The complexity of a particular refinery results from the trade-off between the costs of investment and operating vs the capability to process heavier, less expensive crudes and produce lighter, higher-value transportation fuels or petrochemicals.

The major conversion processes in refining have not changed fundamentally for about six decades, though there have been steady, significant improvements and occasional breakthroughs in product yields, product quality, energy efficiency, and environmental performance. A brief description of refining technology as well as a detailed analysis of life cycle GHG emissions of petroleum-based fuels has been given by the National Energy Technology Laboratory, US Department of Energy (NETL, 2008).

Briefly, crude oil is heated in fired furnaces and separated into different boiling point fractions in atmospheric and vacuum distillation columns. The simplest refining configuration today is a hydroskimming/topping refinery processing a light sweet crude. It includes only a reformer and a distillate hydrotreater in addition to distillation. The reformer increases

the octane of gasoline-range boiling material (naphtha) by dehydrogenating naphthenes into aromatics, isomerizing linear paraffins into branched ones, and converting paraffins into aromatics over a fixed-bed catalyst at moderate pressure. Hydrogen is produced as a by-product. The hydrotreater removes sulfur in a high pressure hydrogen atmosphere by converting it to hydrogen sulfide, also over a fixed bed catalyst. Such a refinery would produce LPG, gasoline, kerosene/jet fuel, diesel/heating oil, and a large amount (30–35%) of low-value heavy fuels.

The next step would be to add a fluid catalytic cracker (FCC) to convert some of these heavy fuels, products from the vacuum distillation column, into diesel, gasoline and lighter gases. The FCC is a complex, atmospheric pressure process where oil vapor is contacted with a fluidized circulating catalyst. Coke is deposited and then burned off continuously from the catalyst in a regeneration step. The FCC is a major source of refinery carbon dioxide and other emissions. In modern refineries, a great deal of equipment is required to reduce sulfur/nitrogen oxides and catalyst particulate emissions from FCC units. An FCC feed hydrotreater, operating at higher pressure than the distillate hydrotreater, would desulfurize the FCC feed and improve the FCC light product yields by saturating aromatic rings. Such a medium conversion refinery would process higher-sulfur crudes and create higher value products than the hydroskimming refinery.

The next step would be to add a coker, a thermal cracking process that can handle the heaviest residue from vacuum distillation and convert it to diesel, gasoline, lighter gases and solid petroleum coke. Such a high conversion refinery could handle the heaviest crudes in its feed and create the maximum value-added between feed and products. In the early 1980s some complex catalytic units were built to hydrotreat heavy residues but the simpler coking process has been the economic choice worldwide since then.

Another major conversion process is hydrocracking, which handles feed similar to the FCC but cracks it in a very high pressure hydrogen atmosphere over a fixed catalyst bed. A refinery can have either of the two catalytic cracking processes or both. Hydrocracking capacity worldwide is about one third that of FCC. Hydrocracking is preferable when a

higher diesel/gasoline ratio is needed and is particularly suited for making very-low-sulfur products. Other refinery processes include (i) naphtha hydrotreating, necessary to treat the reformer feed or for gasoline fractions to meet current low-sulfur specifications, (ii) alkylation that converts FCC gases into high-octane gasoline material, (iii) isomerization, a reforming process that increases the octane of light naphtha, (iv) visbreaking, another thermal process for heavy residues, and (v) a multitude of treating processes to remove impurities and contaminants from various intermediate and product streams.

As refinery complexity and feedstock flexibility increases, more severe hydrotreating for distillates and FCC feed may require more hydrogen than is produced by the reformer; a hydrocracker will definitely require another source of hydrogen. A refinery then needs a hydrogen plant or needs to import hydrogen from an external facility. Most refineries use natural gas and refinery off-gas to produce hydrogen through steam reforming. There are several options and technological opportunities in this area. In 1999, BOC Gases (now a part of The Linde Group) and BP Amoco developed a partial oxidation scheme using the Texaco gasification process to supply hydrogen to a new refinery hydrocracker in Bulwer Island, Australia, and to recover pure carbon dioxide (Ramprasad et al., 1999). Depending on the investment cost and the availability or cost of natural gas, refineries can also use gasification of residues or even of petroleum coke. The Shell Group's Pernis refinery in the Netherlands, one of its largest facilities at 400,000 bbl/day, chose a 1650 t/day heavy residue gasification route to produce hydrogen for a new hydrocracker (Shell, 2009).

12.3.2.1   Heavy Oils Technology

The production of heavy oils and bitumen from tar sands generally requires use of steam in one of several techniques, e.g. cyclic steam stimulation, steam assisted gravity drainage, horizontal cyclic steam, or some combination of these (Anonymous, 2008). If heavy oil is to be transported to a distant refining center, lighter oil must be used as diluent to allow flow in a pipeline. Alternatively, such oil can be partially processed where it is produced and a "syncrude" product then shipped to conventional refineries. The processing of very heavy oil or tar sands occurs through application of essentially conventional refining technology. Coking is the major conversion process, followed by severe hydrotreating of the ensuing products before further processing. As crude oil prices rose in the 2004–2007 period, a great deal of investment was initiated to upgrade Canadian tar sands and to process Canadian heavy oil in northern US refineries.

12.3.2.2   Refining Economics

Refining is a capital-intensive and competitive industry that has not been particularly profitable in the long term, except for short periods and in specific "niche" markets. The most recent example is the "Golden Age" of refining in the United States, lasting less than four years, which was caused by a steep global demand increase and unexpected shut-down of refining capacity. Refining margins are determined by market forces and are affected primarily by factors such as the balance between product demand and available refinery capacity, the differential price between heavy and light crudes, and the global balance of fuel oil. (High differentials and low fuel oil prices tend to cause refineries with simpler "topping" configurations to cut production as their variable margins reach break-even and to favor refineries with cracking capacity that can convert the heavier oils.)

As with other commodities, periodic overbuilding of capacity has caused margins to be cyclical and weather or operational variations in available capacity have caused volatility. New capacity costs have historically been around US$10,000/bbl/day of capacity but have risen to US$20,000–30,000 in recent years. Generally, margins have not justified new capacity construction in OECD countries. Government policies or incentives, niche supply or market conditions, or particular synergies with other petrochemical or power projects have supported new capacity additions, primarily in Asia. With the Golden Age in the past, non-mandatory investments in refining will be difficult to justify in OECD countries in the future.

12.3.3   Greenhouse Gas Emissions

12.3.3.1   Extent of Refinery Emissions in the Life Cycle of Petroleum-based Fuels

Emissions of carbon dioxide from stationary fossil fuel sources account for 60% of total global fossil fuel emissions. Of the major stationary sources, refineries account for 6%, cement manufacture for 7%, and power generation for 78% (CO_2 Capture Project, 2009). A detailed analysis of life cycle GHG emissions of petroleum-based fuels has been conducted by NETL (2008; 2009). The scope of this work is extensive and includes analysis of the impact of different crude sources on the GHG emissions of transportation fuels sold in the United States. A summary of some of their results is given in Figure 12.15. Not surprisingly, a key conclusion is that the extent of GHG emissions that is attributed to refinery processing itself is small (6–10%), compared to the ultimate use of the fuels (80–83%). NETL (2008) conclude that the best way to reduce transportation life cycle GHG emissions is by lower overall use of fuels through more efficient modes of transportation and vehicle efficiency. They estimate, as an example, that seven miles per gallon improvement in light vehicle efficiency would be equivalent to eliminating all oil production, transportation, and processing "well-to-tank" emissions. They consider refineries already efficient and cite ongoing continuous improvement programs in the US industry. Although their study is centered on US transportation fuels, this conclusion is quite general. New capacity in Asia is being built to very high standards of efficiency and environmental performance and, as smaller, less efficient refineries are phased out for economic as well as environmental reasons, global refinery emissions will decrease on a continuing basis.
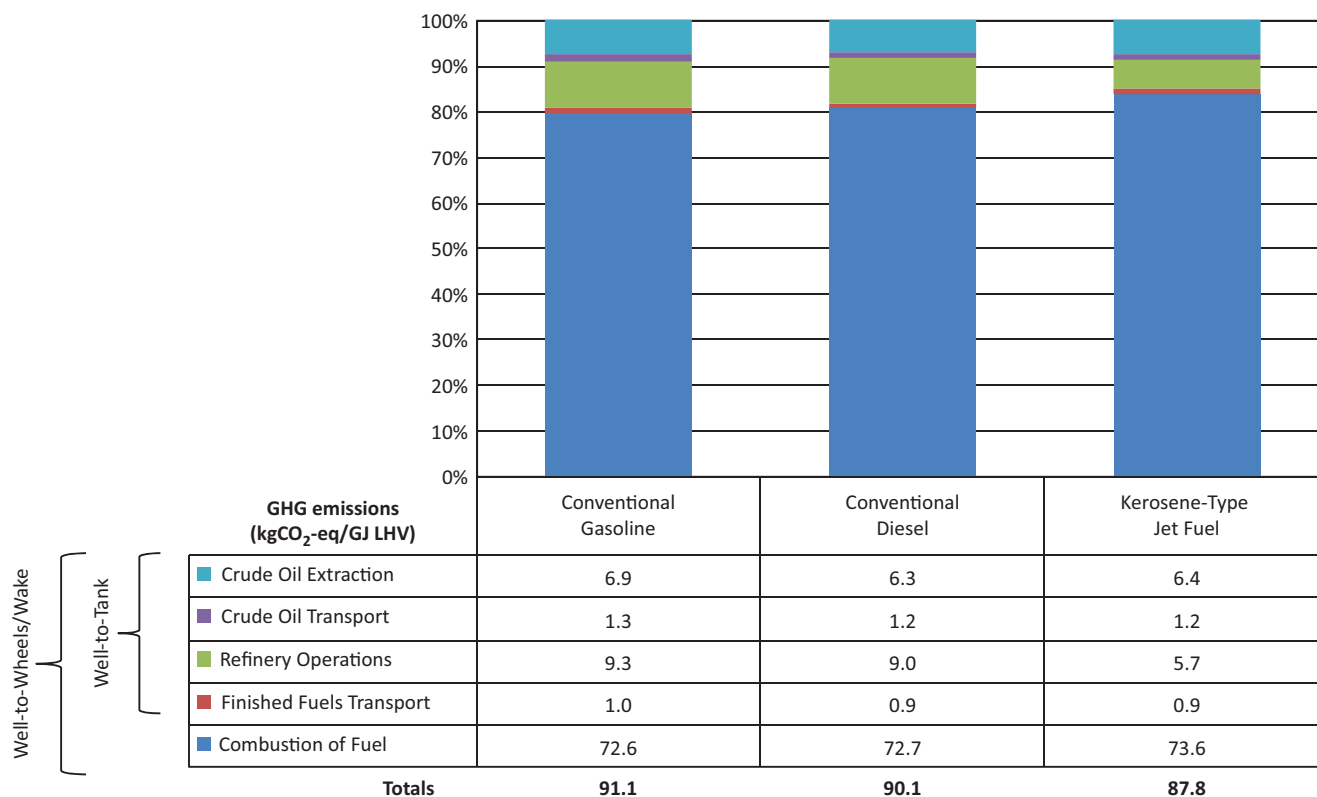
GHG emissions (kgCO$_2$-eq/GJ LHV)	Conventional Gasoline	Conventional Diesel	Kerosene-Type Jet Fuel
■ Crude Oil Extraction	6.9	6.3	6.4
■ Crude Oil Transport	1.3	1.2	1.2
■ Refinery Operations	9.3	9.0	5.7
■ Finished Fuels Transport	1.0	0.9	0.9
■ Combustion of Fuel	72.6	72.7	73.6
Totals	**91.1**	**90.1**	**87.8**

Figure 12.15 | Baseline life cycle emissions of CO$_2$-eq for fuels derived from petroleum and sold or distributed in the United States in 2005. Source: based on NETL, 2009.

Emissions from the production and transportation of heavy oils are higher by 9.5–14 kgCO$_2$/GJ$_{LHV}$ diesel (NETL, 2009), than those from more conventional crudes, which vary by comparable amounts from each other. An analysis of the GHG emissions associated with the production and transportation of different crudes and heavy oils must be conducted in terms of global impact. There is little overall benefit, for example, if the use of particular crude or heavy oil is limited in the United States through a carbon tax or other regulatory measures only to route this crude to an alternative refining center elsewhere in the world. Opportunities for reducing flaring during production, which are higher for some crudes, no doubt will be pursued. The upgrading of heavy oil lends itself to carbon capture and sequestration. Refineries constantly optimize their crude mix on a global basis based on the demand of their market, their configuration, and the cost of crudes relative to their value for a specific refinery. If a globally consistent and well-designed cap-and-trade system emerges, the cost associated with specific feedstocks, including conventional crudes, heavy crudes, or tar sands, should lead to the optimal use of all global resources.

12.3.3.2 Opportunities for Carbon Capture from Refinery Emissions

Carbon dioxide capture at a refinery has been studied by the CO$_2$ Capture Project, a partnership of seven major energy companies working closely with government organizations, academic bodies, and global research institutes (CO$_2$ Capture Project, 2009). The major sources of emissions considered are boilers and fired heaters, fluid catalytic cracker units, and hydrogen production operations. The FCC unit has its own intrinsic combustion emissions due to coke burning during catalyst regeneration. Emissions from other major processes, such as crude distillation, hydrotreating, and hydrocracking, are generated by fired heaters used in the process. Fired heaters can be treated as a group and are amenable to common analysis, optimization, consolidation, and carbon capture approaches. Three CO$_2$ capture approaches are being considered:

- post-combustion: absorption of flue gas CO$_2$ from major sources into MEA (monoethanolamine) solution;

- oxy-firing: use of oxygen instead of air in combustion to produce a high concentration of CO$_2$ in the flue gases thus facilitating capture; and

- pre-combustion: gasification to produce a hydrogen-rich fuel and separate CO$_2$ prior to combustion.

Two recent studies associated with CO$_2$ Capture Project have considered opportunities for carbon capture in refineries. Shell (van Straelen et al., 2009) has evaluated the feasibility of post-combustion capture at a world-scale refinery. They identified scale (1–2 MtCO$_2$/yr) and CO$_2$ concentration (above about 8%) to be major factors in the cost-effectiveness

of refinery carbon capture. They concluded that the best opportunities lie in capturing the emissions from hydrogen production (5–20% of refinery emissions) and large flue gas stacks (another 30% of emissions), finding smaller sources unlikely to be practical. They estimated that such carbon capture would be economical at carbon trading "3–4 times higher than the current." Shell is also studying opportunities for oxy-firing burners and operating the FCC regeneration on oxygen, so as to facilitate CO_2 capture from flue gases. Petrobras and Lummus (de Mello et al., 2009) have studied post-combustion and oxy-firing the FCC and concluded that oxy-firing is feasible and more cost-effective although it would entail higher investment. They did not show absolute cost estimates for using such technology.

The FCC is a major source of refinery emissions. This process has been dominant globally and especially in China for a number of reasons. It was the choice of Reliance for the new refinery in Jamnagar, Gujarat, India. For new capacity, understanding the impact of high carbon costs on the choice of catalytic cracking technology would be worthwhile, especially if demand for diesel continues to increase, as it has in Europe over the last decade.

12.3.4   Conclusions

Current refining technology is likely to continue as the major source of liquid fuels for the next few decades. The global refining industry will grow with some capacity shifting from the OECD, especially the United States, to non-OECD Asian countries, primarily China. Significant technological or regulatory breakthroughs would be needed to change this course, given the scale, technological maturity, and economic fundamentals of this industry. Nevertheless, material opportunities for continuous improvement to decrease refinery GHG emissions and for carbon capture exist and should be developed further.

12.4   Transportation Fuels from Non-petroleum Feedstocks

Fossil fuels other than petroleum can be converted to transportation fuels. Technologies are available and commercially operated today for converting natural gas, coal, or biomass into liquids that closely resemble diesel and gasoline derived from crude oil. These processes involve converting the gas, coal, or biomass first into a synthesis gas (primarily CO and H_2) that is then reacted over specialized catalysts to form liquid hydrocarbons. The most widely used synthesis process for making transportation fuels today is Fischer-Tropsch (F-T) synthesis. The crude Fischer-Tropsch liquid product (FTL) can be refined into middle distillate fuels (65–85% of the final liquid volume produced), naphtha or gasoline (15–25% of the final product), and heavy waxes or lubricating oils (0–30% of the final product) (Fleisch et al., 2002). Oxygenated fuels, such as methanol, higher alcohols (C3 to C8, propanol to octanol), or dimethyl ether (DME), can also be produced from synthesis gas

using different catalysts, and methanol can be further processed catalytically into synthetic gasoline and synthetic liquefied petroleum gas (LPG). There are other technologies, not yet commercialized, that pursue conversion through other intermediates than synthesis gas such as acetylene (Biello, 2009) or methanesulfonic acid (MSA) (Richards, 2005). Technology is also available for direct liquefaction of coal to produce a mix of products, including synthetic gasoline, diesel, LPG, and jet fuel, as well as a variety of chemicals.

12.4.1   Gas to Liquids

It is estimated that nearly 40% (or 71 trillion cubic meters) of the world's current natural gas reserves are "remote" or "stranded," defined as too far from the market place for economic delivery via pipelines. Natural gas resources in Australia, Trinidad and Tobago, and Qatar are good examples. In these instances, gas monetization is sought via liquefying the gas for shipping. The siting of facilities to re-gasify liquefied natural gas is now very challenging in many countries so, increasingly, gas monetization is being pursued via conversion to liquid fuels and chemicals. The high oil prices of recent years are providing a significant impetus for these so-called gas-to-liquids (GTL) efforts. Another driver for the advancement of GTL is the reduction or elimination of the flaring of associated gas. Rather than flaring gas associated with crude oil production, it could be converted via GTL technology into a synthetic crude oil and blended with the produced crude oil for shipping to refineries. The estimated 425 million cubic meters of gas flared daily if converted via GTL technology could produce some 1.5 million bbl/day (3.3 EJ/yr) of additional liquid hydrocarbon products.

Billions of dollars have been invested in GTL technology development over the last several decades by major oil companies and several technology companies. The investment has been primarily in technology for Fischer-Tropsch conversion. (The term GTL in popular usage usually refers to Fischer-Tropsch systems.) A lower level of investment has gone into technologies for producing other liquids, including methanol, higher alcohols, DME, and synthetic gasoline (via methanol). At current rates of commercial deployment, GTL systems could be displacing as much as 1 million bbl/day (2.2 EJ/yr) of petroleum-derived transportation fuels by 2020.

12.4.1.1   Fischer-Tropsch Technology

Transportation fuels are produced by Fischer-Tropsch processing, with chemical feedstocks as byproducts. F-T systems consist of three major integrated sub-systems: (i) syngas production, (ii) syngas conversion to a syncrude, and (iii) syncrude upgrading to finished products.

First, syngas (consisting predominantly of CO and H_2) is produced from methane (CH_4) by reforming using one of a variety of proven technologies. For smaller plants, steam methane reforming (SMR) is the technology of choice where natural gas is reacted with steam at

high temperatures and pressures in an externally-heated multi-tubular reactor over a nickel-based catalyst. At plant sizes over about 10,000 bbl/day, autothermal reforming (ATR) or partial oxidation reforming (POX) have become the norm. (The larger size justifies the costs of a dedicated onsite air separation unit for oxygen production.) In these systems, part of the natural gas is combusted with oxygen and the hot combustion products (CO_2 and H_2O) react with additional natural gas over a nickel-based catalyst to form syngas. Most of the heat requirements of the endothermic reforming reaction are met by the heat from the combustion process.

Following reforming, syngas is converted over a catalyst into predominantly long chain paraffinic hydrocarbons with water as a side product. The reaction is quite exothermic and great care must be taken to remove the heat from the reaction vessels. Cobalt-based catalysts have become the norm because of their much higher activity and selectivity for producing the desired paraffins compared with traditional iron-based catalysts. The former are optimized to produce a heavy wax intermediate and reduce the formation of lighter material (C1 to C5). The CO_2 yield from the F-T reactor is less than 1%. The wax is hydrotreated with additional hydrogen in the "upgrading" section to make primarily diesel and naphtha as well as other high value materials such as lube oils, jet fuel, and detergents. The iron-based catalysts produce a broader product portfolio including branched hydrocarbons (gasoline), olefins, and oxygenates along with the paraffins. They still find applications in coal-to-liquids because of the water gas shift activity of these catalysts, which produces additional hydrogen from CO through reaction with water. Coal-to-liquids are discussed further in Section 12.6.

Upgrading of F-T syncrude to finished products, the third and final step in a GTL system, is a well-proven conventional refining step. Paraffinic hydrocarbon chains are hydrocracked into shorter chains, predominantly in the diesel range (C_8 to C_{13} hydrocarbons). A small desirable degree of isomerisation can be achieved to provide proper diesel blending properties.

The basic catalytic reaction for syngas conversion was discovered in the 1920s by Franz Fischer and Hans Tropsch, two German scientists. It was sparingly used after its discovery, but there has been a resurgence of interest over the last 30 years supported by billions of dollars of research and development investments. A number of technologies that use proprietary catalysts have been developed by Sasol, Shell, ExxonMobil and other companies:

- Sasol, a South African company, has almost 50 years of experience with F-T technology, mostly in connection with coal conversion. Current production at their Sasolburg and Secunda facilities in South Africa is about 135,000 bbl/day (from coal). Cumulative production of F-T fuels using Sasol technology exceeds one billion barrels. The Sasol process has undergone significant advancements over the years from the original fixed bed technology (Arge process) to a circulating bed process (Advanced Synthol Process). The Petroleum Oil and Gas Corporation of South Africa (PetroSA), the state-owned GTL producer, started up its

Mossgas plant in 1993 based on Sasol technology and now produces 22,500 bbl/day of finished products. The latest Sasol technology development is its Slurry Phase process. The process was commercialized in the Oryx GTL facility in Ras Laffan, Qatar, in 2006, which produces about 34,000 bbl/day and cost nearly US$1 billion to build. The process involves bubbling hot syngas through a slurry consisting of catalyst particles suspended in liquid hydrocarbon products. The capacity of a single Sasol slurry reactor is 17,500 bbl/day. In partnership with Chevron and the Nigerian National Petroleum Corporation, Sasol is providing technology, engineering services and engineering support for the construction of a carbon-copy of the Oryx facility on a site adjacent to the Escravos River in Nigeria. The Escravos GTL plant will convert about 8.5 million cubic meters per day of currently-flared gas into 22,300 bbl/day of diesel, 10,800 bbl/day of naphtha and 1000 bbl/day of LPG. The project was hit by global construction cost escalations starting in 2007 and may end up costing more than five times the same-sized Oryx plant, some US$5.9 billion.

- Shell is the other leader in commercial gas-to-liquids experience as a result of its GTL plant in Bintulu, Malaysia (the Shell Middle Distillate Synthesis plant). The Shell technology is a tubular fixed bed reactor containing a proprietary cobalt-based catalyst. The Bintulu plant was designed to convert 2.8 million m^3/day of gas into 12,500 bbl/day of GTL products. It started operation in May 1993. In 1997, an explosion in the air separation unit damaged the plant. The plant was rebuilt and production restarted in mid-2000 and has been operating since that time at full capacity. The Bintulu plant was the inspiration for Shell's Pearl gas-to-liquids project in Ras Laffan, Qatar. Pearl is designed to produce 140,000 bbl/day in four trains of 35,000 bbl/day each. The trains are planned to come online between 2011 and 2014. The overall project cost announced in 2001 of US$5 billion has ballooned to allegedly US$20 billion (nominal estimate, circa 2008), mainly due to escalating construction costs. However, the oil price has risen fourfold as well, making all products more valuable and compensating for the higher capital costs.

- ExxonMobil's Advanced Gas Conversion for the 21st Century (AGC-21) is a Fischer-Tropsch hydrocarbon synthesis process that converts syngas to heavy hydrocarbons over a cobalt-based catalyst suspended in a slurry. The AGC-21 hydrocarbon synthesis technology is protected by about 1200 patents and has not yet been operated commercially. In the last decade, ExxonMobil explored several commercialization options. It advanced a 160,000 bbl/day project in Qatar, but abandoned the project (and perhaps the technology) in 2006.

- BP has been involved with GTL technology since the 1980s. It operated a GTL test facility in Nikiski, Alaska, from 2002–2009 and continues to pursue commercial applications. The test facility converted about three million cubic feet of natural gas into an estimated 300 barrels of synthetic crude a day. The BP technology uses a cobalt-based catalyst in a tubular fixed bed reactor. BP is licensing the technology and is pursuing projects around the globe.

- Conoco was an aggressive player in GTL starting in 1998, pursuing a catalytic partial oxidation process for syngas production and a slurry phase reactor with cobalt-based catalyst for F-T conversion. A 400 bbl/day pilot plant in Ponca City, Oklahoma, was approved in 2001, and a large commercial project in Qatar was being pursued. However, the technology was abandoned shortly after Conoco merged with Phillips in 2002.

- Rentech is focused on the development of an iron-based catalyst in a slurry-phase process to be able to utilize syngas derived from not only natural gas but also solid or liquid hydrocarbon feedstocks. The Rentech F-T process was verified in a 235 bbl/day facility in Pueblo, Colorado, in 1993. Rentech is licensing their technology and pursing numerous projects with different feedstocks.

- Syntroleum's GTL process has been under development since the 1980s. It involves the use of a cobalt-based catalyst in a slurry to convert syngas produced from a proprietary air-fed autothermal reformer. A 70 bbl/day demonstration facility was successfully operated, but no commercial project has advanced.

- World GTL in partnership with Petrotrin, the Petroleum Company of Trinidad and Tobago, is building a small GTL plant using a refurbished and re-engineered methanol plant. They have developed their own cobalt based, multi-tubular F-T technology. There have been significant cost overruns and the project went into receivership in 2010. Nevertheless, the 2,250 bbl/day plant is expected to come on line in 2012, and World GTL is targeting small gas fields and associated gas with its low-cost modular technology.

- There are a number of related advanced technology developments underway. Petrobras is piloting a micro-reactor based GTL system developed by Velocys and CompactGTL (CompactGTL, 2010). Micro-reactors are low-cost modular systems where the reactions and the heat exchange are conducted in small channels of about 1mm diameter. These systems have a much smaller footprint than conventional systems and could be deployed on platforms or floating vessels to convert off-shore associated gas. Another major development underway for more than 15 years is the use of ionic membranes to separate oxygen from air and to react the oxygen with natural gas to syngas. A smaller footprint and cost reduction of 25% or more over conventional reformers have been touted by the lead developer, Air Products (Air Products, 2008).

Energy and Environmental Performance of F-T Systems

The energy efficiency of a large modern commercial GTL plant today (see Figure 12.16) is about 60–65% on a LHV basis (53–58% HHV basis). Its carbon efficiency (fraction of carbon input as natural gas that appears in the liquid products) will reach 75–80%. For comparison, the methanol process is more efficient than GTL with today's advanced technologies
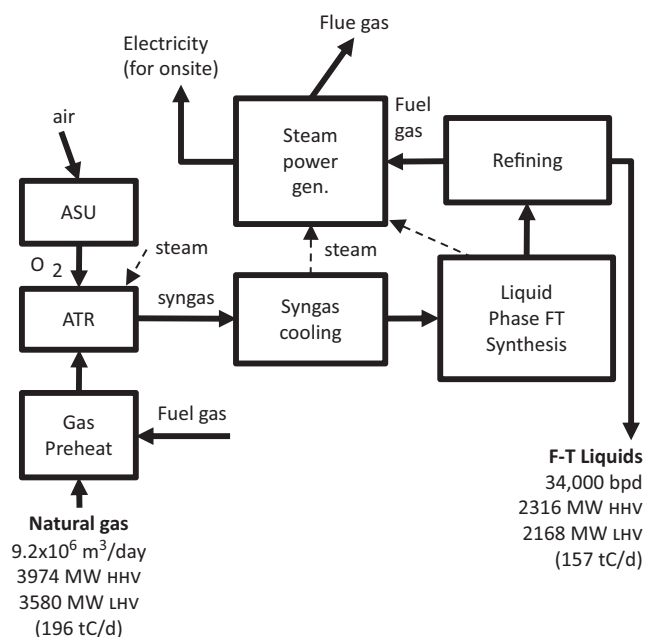

Figure 12.16 | Overall energy and carbon balance for a modern two-train GTL facility. Source: based on Simbeck and Wilhelm, 2007.

already having energy and carbon efficiencies of about 70% and 85%, respectively.

Two processes basically determine the overall efficiency of a GTL plant: (1) the inherent water production in the conversion of methane to higher hydrocarbons (typically one barrel of water will be produced for every barrel of hydrocarbon liquid) and (2) process fuel losses, which refers to the combustion of some of the feed methane (or fuel gas derived therefrom) to provide the heat needed for reforming. From a theoretical perspective, the overall methane-to-liquids reaction can be represented as:

$$(12 + x)CH_4 + (5.5 + 2x)O_2 \Rightarrow C_{12}H_{26} + (11 + 2x)H_2O + x(CO_2) \qquad (1)$$
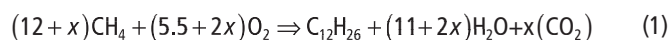
The maximum efficiency will be for the case where x is zero (no net CO_2 produced). This theoretical maximum is 78% (LHV). The remaining 22% of the input energy went into making water. At this maximum thermal efficiency, the methane carbon conversion into liquid products would be 100%. For a carbon efficiency of 75% (approximately the level with current technology), x is about three. Technology advances are projected to raise energy and carbon efficiencies to as high as 73% and 90%, respectively, within the next decade (Fleisch et al., 2003). This would make the carbon efficiency of the GTL process comparable to that of petroleum refining.

For a large, modern GTL facility that vents CO_2, the life cycle GHG emissions associated with the F-T liquid products amounts to some 101 kgCO_2-eq/GJ$_{LHV}$ (where GJ stands for gigajoule) or about 10% above GHG emissions associated with an equivalent amount of crude-oil

derived products.[10, 11] The prospects for reducing these emissions are limited, since only a relatively small amount of CO_2 is available for capture. If available CO_2 were to be captured at a GTL facility today, life cycle GHG emissions would be about 10% below emissions from an equivalent amount of crude-oil derived products. The expectation is that further advances in GTL technology will reduce the amount of CO_2 available for capture, which makes this figure a lower bound on potential GHG emissions of GTL fuels.

Prospective F-T Economics

The gap is widening between the value of natural gas and that of liquid transportation fuels such as diesel and gasoline, influenced by oil prices consistently above US$60/bbl and increasing bullishness regarding future natural gas supplies (see Section 12.7.2.2). In the largest market, the United States, gasoline and diesel sold for two to four times Henry Hub natural gas prices on an energy equivalent basis in recent times (Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange). During most of the 1980s and 1990s, gas hovered around US$2/GJ while diesel and gasoline averaged US$4–6/GJ. More recently, the gap has widened because of plentiful gas supplies and the capping of gas prices by coal in the competition for power generation. In 2009, we have seen gas prices below US$3/GJ while low sulphur diesel was at US$14/GJ and above. These are strong economic drivers for GTL especially with commercially proven technologies. It can be shown that at oil prices of US$60/bbl, a delivered gas price of about US$8/GJ is needed to achieve a similar net present value for GTL and LNG (liquefied natural gas) projects. At higher oil prices and/or lower gas prices, GTL is economically advantaged over LNG while at lower oil prices and/or higher gas prices LNG is the economic choice.

The economics for an integrated upstream gas field and GTL plant will typically be more attractive than those for a stand-alone GTL plant. Shell's 140,000 bbl/day Pearl project is an example of an integrated project. It includes gas production platforms, gas processing plants and the GTL facilities. The economic returns from the condensates and LPG in the natural gas are high, putting less demand on the return from the GTL project.

Capital costs of GTL Fischer-Tropsch projects dropped from about US$_{2005}$$80,000 per bbl/day (US$_{1991}$$60,000) of installed capacity in 1991 for Mossgas to just below US$_{2005}$$29,000 per bbl/day (US$_{2006}$$30,000) installed capacity for Oryx in 2006. These costs made GTL economic with oil at US$20/bbl. Capital costs have more than doubled in the last four years, however, due to sky rocketing oil prices and the corresponding

increases in project costs in the oil and gas industry. Many GTL projects have been delayed for a "cooling down" period. However, the first train of the Shell Pearl project started up in mid-2011, to be followed by the other three trains through 2014. This project may prove the techno-economic attractiveness of large scale GTL once and for all and set the stage for widespread global applications with ongoing improvements. Meanwhile, research and development is continuing and will also contribute to reducing capital costs as it has in the past.

Thus, GTL has the potential to become a prominent part of the international energy business. Continued high oil prices and the widening gap between gas prices and oil prices will favor GTL projects. Most importantly, the concerns of technology risks will wane with commercial plants operating safely and reliably around the world. The problem of technology access will disappear: an increasing number of licensing opportunities and patents are expiring.

12.4.1.2   Methanol to Gasoline

Production of methanol from natural gas is a well-established technology (Cheng and Kung, 1994; Olah et al., 2009). Methanol consumption globally exceeds 40 Mt/yr primarily in chemical processing. Use of methanol as a vehicle fuel attracts considerable interest in some provinces of China today (Dolan, 2008), as it did in the 1970s and 1980s in the United States, where interest has since faded largely as a result of health and environmental concerns from the use of methanol-derived MTBE (methyl tert-butyl ether) as an additive to gasoline. There is renewed interest in higher alcohols for both gasoline and diesel blending (IGP, 2010). These alcohols overcome some disadvantages of methanol and ethanol and have been shown to increase engine efficiencies and lower tailpipe emissions (Yacoub et al., 1997). Furthermore, there is now growing interest in China, the United States and elsewhere in the production of synthetic gasoline from synthesis gas via a methanol intermediate. This so-called methanol-to-gasoline process is the subject of this section.

The first step is methanol production by reforming of natural gas into synthesis gas (CO and H_2), which is then converted over a catalyst to methanol. The two most common reforming technologies, SMR and ATR, have been described in Section 12.4.1.1. A syngas H_2/CO ratio of about two leaving the reformer will optimize methanol synthesis yields, but reforming typically yields a syngas with H_2/CO higher than two. One option for reducing the H_2/CO ratio is to feed recycled CO_2 to the reformer. Katofsky (Katofsky, 1993) showed that this has the benefit of increasing methanol yield and overall process efficiency by several percentage points.

Two companies currently offer technology for synthesis of gasoline from methanol. A key distinction between the technologies is that the technology offered by Haldor Topsoe utilizes an initial single-step conversion of syngas into DME/methanol, followed by conversion to gasoline

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10   This estimate includes 9.10 kgCO$_2$-eq/GJ$_{LHV}$ associated with extraction, preprocessing, and transportation of the feedstock natural gas (based on the GREET model (Argonne National Laboratory, 2008)).

11   If natural gas that would otherwise have been flared (a relatively small potential resource for GTL) were the feedstock, then the net life cycle GHG emissions associated with these GTL fuels would be considerably less than for equivalent petroleum-derived fuels, since the GTL fuels would be displacing the petroleum-derived fuels (FWI, 2004) while eliminating the emissions from the flared gas.

in a separate reactor (Nielsen, 2009). The ExxonMobil process involves methanol production from syngas followed by partial conversion of methanol to DME in a separate reactor, followed by conversion of the DME/methanol mixture into gasoline in a third reactor (Tabak et al., 2009). In either case, most of the DME/methanol mixture that flows to the gasoline synthesis reactor is converted in a single pass over the catalyst. Some propane/butane (LPG) and a small amount of methane are coproducts.

Because the H/C ratio of methane is higher than that of the final gasoline product, no significant CO_2 by-product stream is available for capture and storage, giving natural gas-to-MTG systems a carbon footprint not substantially different from petroleum-derived gasoline.

12.4.2   Direct Coal Liquefaction

Direct coal liquefaction refers to a process in which pulverized coal reacts with a hydrogen-donor solvent over a catalyst, causing hydrocracking of the coal into liquids. Direct liquefaction is distinct from indirect liquefaction. As discussed in Section 12.4.3, indirect liquefaction utilizes coal gasification followed by a separate catalytic step to convert the gasified product into liquid fuels. (Fischer-Tropsch fuels are perhaps the best known of the different fuels that can be produced via indirect liquefaction.)

Direct coal liquefaction will produce not only gasoline, diesel, LPG, and jet fuel, but also a variety of chemicals such as benzene, toluene, xylene, and other raw olefins to further produce ethylene and propylene. The reaction can be summarized as follows:

$$nC + (n+1)H_2 \rightarrow C_nH_{2n+2} \qquad (2)$$

The first generation of direct coal liquefaction technology was developed during World War II. Germany was the first country to realize the industrialization of direct coal liquefaction. Twelve direct coal liquefaction plants were built and the total capacity exceeded 4 Mt/yr. However, the first generation technology was limited by its harsh reaction condition (Pressure: around 70 MPa) and costly catalysts. After World War II, all the plants were shut down due to technical defects and economic disadvantage driven by the development of cheap oil. The 1970s oil crisis brought attention back to direct coal liquefaction. Many countries developed a wide range of modern coal liquefaction technologies (Pressure: 10~30 MPa and less expensive catalysts): American H-Coal and Hydrocarbon Technology, Inc. (HTI), the German Integrated Gross Oil Refining (IGOR) technology, the Japanese NEDOL technology, and others. These technologies completed 350~600 t/day pilot tests but did not achieve large scale industrialization. Table 12.14 lists known technologies developed to at least the 50 t/day coal input scale. The main differences between these processes lie in catalysts, reactors, hydrogen donor solvents, and system design.

Table 12.14 | World testing of coal liquefaction technologies.

Single stage processes	Two stage processes
• Kohleoel (Ruhrkohle, Germany) • NEDOL (NEDO, Japan) • H-Coal (HRI, USA) • Exxon Donor Solvent (EDS) (Exxon, USA) • SRC-I and II (Gulf Oil, USA) • Imhausen high-pressure (Germany) • Conoco zinc chloride (Conoco, USA)	• Catalytic Two-Stage Liquefaction (CTSL) (USDOE and HRI, now HTI, USA) • Liquid Solvent Extraction (LSE) (British Coal Corp., UK) • Brown Coal Liquefaction (BCL) (NEDO, Japan) • Consol Synthetic Fuel (CSF) (Consolidation Coal Co, USA) • Lummus ITSL (Lummus Crest, USA) • Chevron Coal Liquefaction (CCLP) (Chevron, USA) • Kerr-McGee ITSL (Kerr-McGee, USA) • Mitsubishi Solvolysis (Mitsubishi Heavy Industries, Japan) • Pyrosol (Saarbergwerke, Germany) • Amoco CC-TSL (Amoco, USA) • Supercritical Gas Extraction (SGE) (British Coal Corp., UK)

Source: DTI, 1999.

The most active country today in direct liquefaction is China, which became a net oil importing country in 1993. Since then, the fraction of oil imported has been increasing, and it reached about 50% by the end of 2008. Concern about energy security gives impetus for making oil from coal in China. Direct coal liquefaction became a major candidate because it is believed to be more energy efficient and less water consuming than many alternatives.

In 2001, China's Shenhua Group, the largest coal company in the world, started development of a demonstration project to produce one Mt/yr of liquids from coal by direct liquefaction. In early 2009, the facility conducted the first test run which lasted about 300 hours and then shut down as planned. This project is ongoing and is expected to provide improved understanding about potential energy and economic performances of this technology (see Box 12.2).

12.4.2.1   Process Description

Direct coal liquefaction includes a catalytic liquefaction step in the presence of hydrogen followed by solid-liquid separation and upgrading. Pulverized coal is blended with a solvent and the catalyst, together making a coal slurry. In the liquefaction unit, weak-bond breaking is achieved, leading to free radical hydrogenation. Then, the inorganic minerals and un-reacted coal are removed by a series of solid-liquid separation processes such as vacuum distillation, filtration, extraction, and sedimentation. Finally, a catalytic hydrogenation process is required to increase the hydrogen-to-carbon ratio in the liquid product and remove impure elements.

Generally speaking, apart from anthracite, all other types of coal can be liquefied to some extent. In rough terms, the difficulty of liquefaction increases with the age of the coal: peat < young lignite < lignite < high-volatile bituminous coal < low-volatile bituminous coal. In addition, excessive ash content also has a negative impact on coal liquefaction.

Box 12.2 | Shenhua Direct Coal Liquefaction Demonstration Project

China's Shenhua Group's direct coal liquefaction demonstration project in Ordos, Inner Mongolia Autonomous Region, China, is designed to produce 1 Mt/yr of oil. The Chinese government approved the project in 2001, construction started in August 2004, and the first testing run succeeded in early 2009.

Shenhua developed its own synthetic catalyst to lower costs. Hydrogen donor solvent cycle is used to mitigate the slurry properties. A slurry bed compulsory intra-circulation reactor is used to improve the capacity of reaction. A mix of advanced and mature unit technologies reduces project risks.

The process flow of Shenhua direct coal liquefaction project is shown in Figure 12.17. At present, 1.08 Mt of liquefied oil can be produced with the input of 4.10 Mt of coal, of which 1.32 Mt is used for hydrogen production and 0.53 Mt for industrial boiler firing. Of the liquefied oil, 70% is diesel and 20% is naphtha. The naphtha products, with a high content of aromatics, are very good reforming materials. The water consumption in this project is about 7 to 8 tonnes of water per tonne of product.
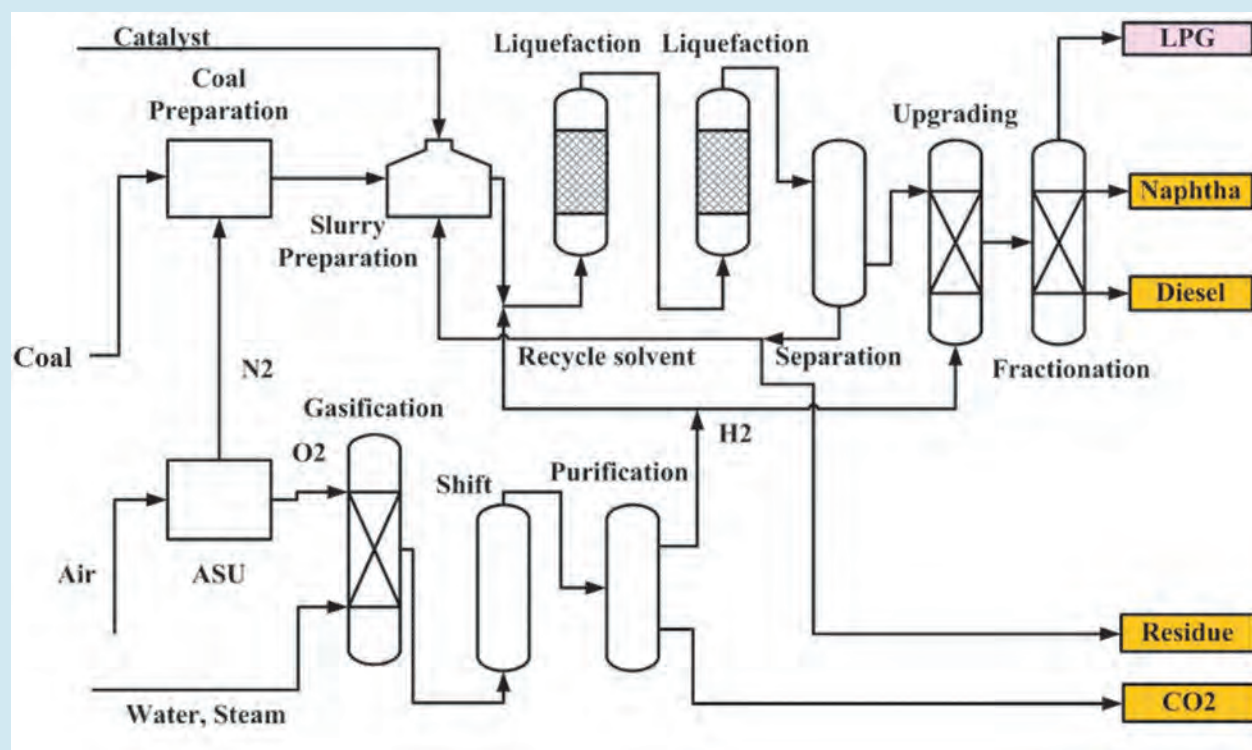
Figure 12.17 | Shenhua direct coal liquefaction demonstration project process flow.

The liquefied oil from direct coal liquefaction, including naphtha, diesel, and liquefied heavy oil, retains some characteristics of raw coal, such as a high content of aromatic hydrocarbons and hetero-atoms (e.g., Oxygen, Nitrogen). A process of hydrogenation is carried out to upgrade the quality of the liquefied oil, which causes the refining costs to be much higher than for conventional petroleum refining.

12.4.2.2   Resource Consumption and Economic Performance

Compared with indirect coal liquefaction and other coal conversion technologies, the efficiency of direct coal liquefaction is higher, up to 60%. Shenhua estimates that the coal consumption of a direct coal liquefaction project is about 0.061 tonne of coal equivalent (tce) per

GJ of liquid product, compared with 0.075 tce/GJ for indirect coal liquefaction.

Water consumption is always a big concern for coal conversion. Compared to other conversion technologies, direct coal liquefaction appears to be relatively lower in specific water consumption at about 8 t water per metric tonne of product (t/t), compared with about 11–12 t/t for indirect coal liquefaction. Water is mainly consumed in the gasification unit for providing hydrogen for hydrocracking and the hydrogenation upgrading processes.

The investment of a direct coal liquefaction plant is still uncertain. The first-of-a-kind plant may cost US$100,000 to US$150,000 per bbl/day output capacity. This number can be decreased with further technology development and improvements in engineering.

12.4.2.3   Carbon Dioxide Emissions

In a coal liquefaction plant producing one Mt/yr of liquids, the carbon dioxide emissions will amount to more than 3.6 Mt/yr, excluding emissions from combustion of the liquid products. The plant CO_2 emissions are predominantly (about 80% of emissions) from the hydrogen production unit. The CO_2 leaves this unit in high concentration (87–99%), which can facilitate low-cost capture of CO_2 for underground storage. (Other CO_2-containing emission streams, e.g., flue gas from the flare system, have relatively low concentrations of CO_2, making capture for storage more difficult.) About one-third of carbon input as coal is available for capture as a relatively pure stream from the H_2 production plant. In this respect, direct coal liquefaction has some similarity to gasification-based coal-to-fuels and coal-to-chemicals processes, since a pure stream of CO_2 is available (just as there is in gasification-based processes). For additional discussion of direct versus indirect liquefaction, see Williams and Larson (2003) and Lepinski et al. (2009).

12.4.3   Gasification-based Liquid Fuels from Coal (and/or Biomass)

There is growing interest in making synthetic fuels from coal – known as coal-to-liquid (CTL) fuels – in light of coal's relatively low prices and the abundance of coal in China, the United States, and other countries that are not politically volatile. Much of this attention has been focused on so-called indirect liquefaction to produce Fischer-Tropsch liquids (Bechtel Corporation et al., 2003; van Bibber et al., 2007; Bartis et al., 2008; AEFP, 2009). Synthetic gasoline (made via a methanol intermediate, see Section 12.4.1.2) is also beginning to attract interest (AEFP, 2009).

Coal can do much to improve energy security if it is used to make liquid fuels. Moreover, these synfuels would be cleaner than the crude oil products they would displace (having essentially zero sulfur and other

contaminants and low aromatics content). Also, if produced using modern entrained flow gasifiers, the air pollutant emissions from the production facility would be extremely low. When synthetic fuels are made from coal without capture and storage of by-product CO_2, however, net fuel-cycle GHG emissions are about double those from petroleum fuels they would displace (AEFP, 2009). And even with carbon capture and storage (CCS), the net GHG emission rate would be only about the same as the crude oil products displaced.

One approach to reducing GHG emissions below petroleum-fuel levels is to exploit negative GHG emissions opportunities to offset the emissions. One important opportunity is synthetic fuels production from biomass with CCS (Larson et al., 2006). An intrinsic feature of synthetic fuels production from coal or biomass is the production of a by-product stream of pure CO_2, accounting for about one half of the carbon in the feedstock. If this CO_2 can be captured and stored via CCS while producing synthetic fuels from sustainably grown biomass, the biofuels produced would be characterized by strong negative GHG emissions, because of the geological storage of photosynthetic CO_2. However, sustainably-recovered biomass is expensive, and the size of the biomass-to-liquid (BTL) facilities will be limited by the quantities of biomass that can be gathered in a single location – which implies high specific capital costs for BTL.

The shortcomings of the BTL with CCS option could be overcome to an extent by coprocessing biomass with coal in the same facility. The economies of scale inherent in coal conversion could thereby be exploited and the average feedstock cost would be lower than for a pure BTL plant. And if CCS were carried out at the facility, the negative CO_2 emissions associated with the biomass could offset the unavoidable positive emissions with coal (Figure 12.18), leading to liquid fuels with low, zero, or negative fuel-cycle emissions depending on the relative amounts of coal and biomass input (AEFP, 2009; Larson et al., 2010; Liu et al., 2011a). Interest in the CBTL-CCS concept is growing in the United States (Tarka et al., 2009).

The equipment for gasification-based production of liquid fuels from coal and biomass are commercial or nearly-commercial in all cases. Coal gasifiers are commercially available and deployable today, with more than 420 gasifiers already in commercial use in some 140 facilities worldwide (AEFP, 2009). The technology for cogasifying biomass and coal is close to being ready for commercial deployment; the commercial Buggenum IGCC facility in the Netherlands has been cogasifying coal and some biomass in a coal gasifier since 2006 (van Haperen and de Kler, 2007). Stand-alone biomass gasification technology is an estimated five to eight years from being ready for commercial-scale deployment (AEFP, 2009). Technologies for converting syngas into Fischer-Tropsch diesel and gasoline are in commercial use today. Those for making synthetic gasoline via methanol can be considered commercially deployable (AEFP, 2009), with technology offered by vendors such as Haldor-Topsoe (Nielsen, 2009) and ExxonMobil (Tabak et al., 2009), and projects in development (Doyle, 2008; ExxonMobil, 2009). See Section 12.4.1.2.
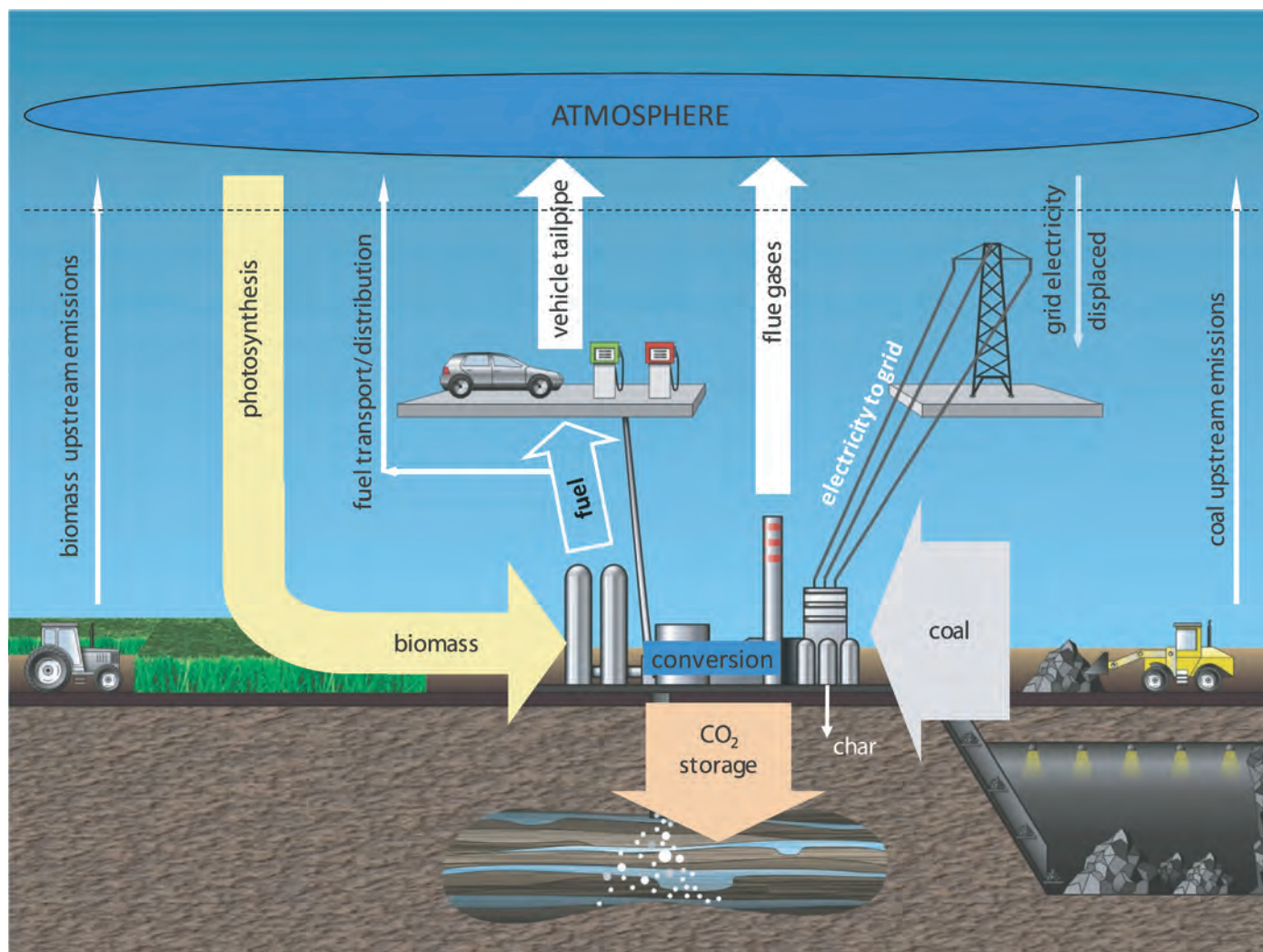
Figure 12.18 | Carbon flows for conversion of coal and biomass to liquid fuels and electricity. When biomass is approximately 30% of the feedstock input (on a higher heating value basis), the net fuel cycle GHG emissions associated with the produced liquid fuels and electricity would be less than 10% of the emissions for the displaced fossil fuels. Source: Larson et al., 2010.
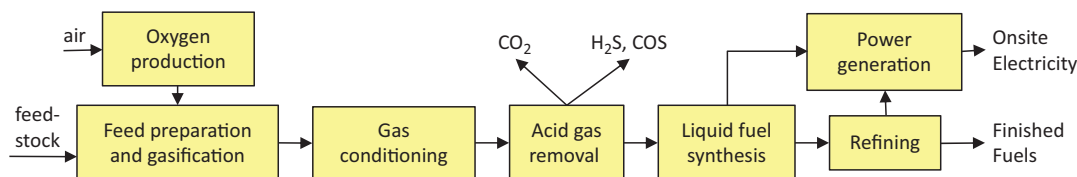

Figure 12.19 | Production of liquid fuels from coal and/or biomass feedstocks.

12.4.3.1   Process Descriptions

Figure 12.19 illustrates generically gasification-based production of liquid fuels from coal or biomass. The feedstock is gasified in oxygen and steam, with subsequent gas conditioning that includes cleaning of the raw synthesis gas (syngas) and in some cases adjusting the composition of the syngas using a water gas shift reaction to achieve the requisite H_2:CO ratio for downstream catalyst-assisted synthesis into liquids. Prior to synthesis, CO_2 and sulfur compounds are removed in

the acid gas removal step to increase the effectiveness and reduce the required size of downstream equipment, as well as avoid sulfur poisoning of catalysts. The CO_2 may be vented (-V) or captured and stored underground (-CCS). The liquid fuel synthesis island is designed with recycle (RC) of unconverted syngas to maximize liquids production. A purge stream from the recycle loop, together with light gases generated in the refining area, provide fuel for power generation, which primarily goes to meet onsite needs. (Alternatively, as discussed in Section 12.6, if none – or only some – of the unconverted syngas is recycled, the
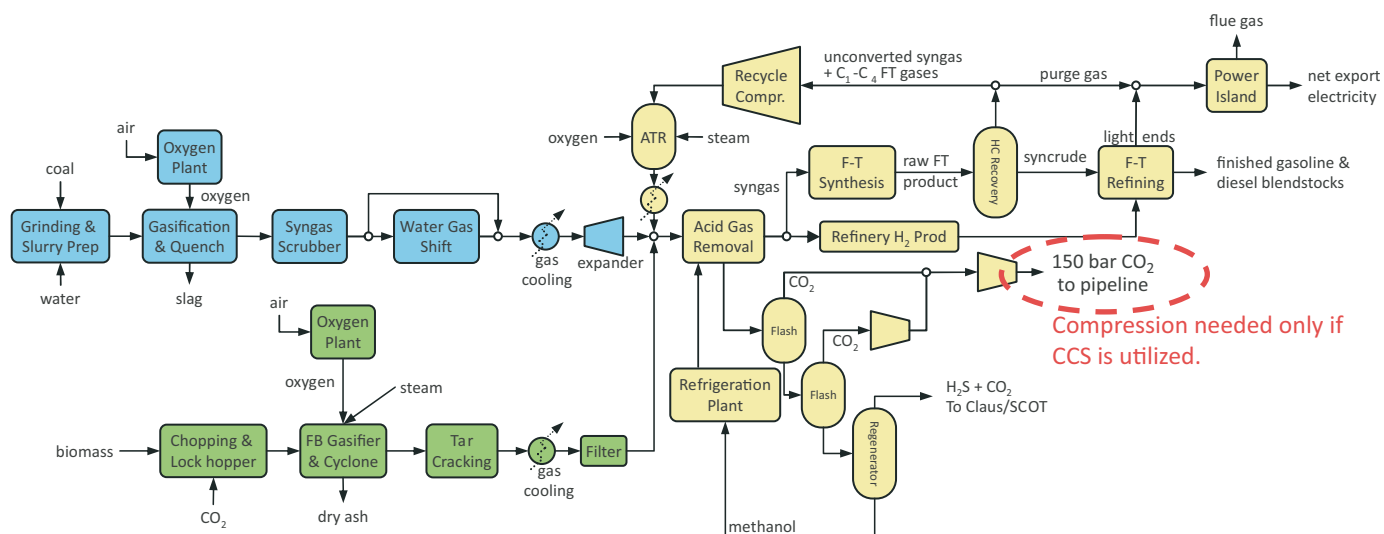
Figure 12.20 | Alternative process configurations for maximizing production of FTL from coal (CTL-RC-CCS, blue-shaded components) or from biomass (BTL-RC-CCS, green-shaded components) with capture and storage of carbon. Yellow-shaded components are common to both CTL and BTL systems.
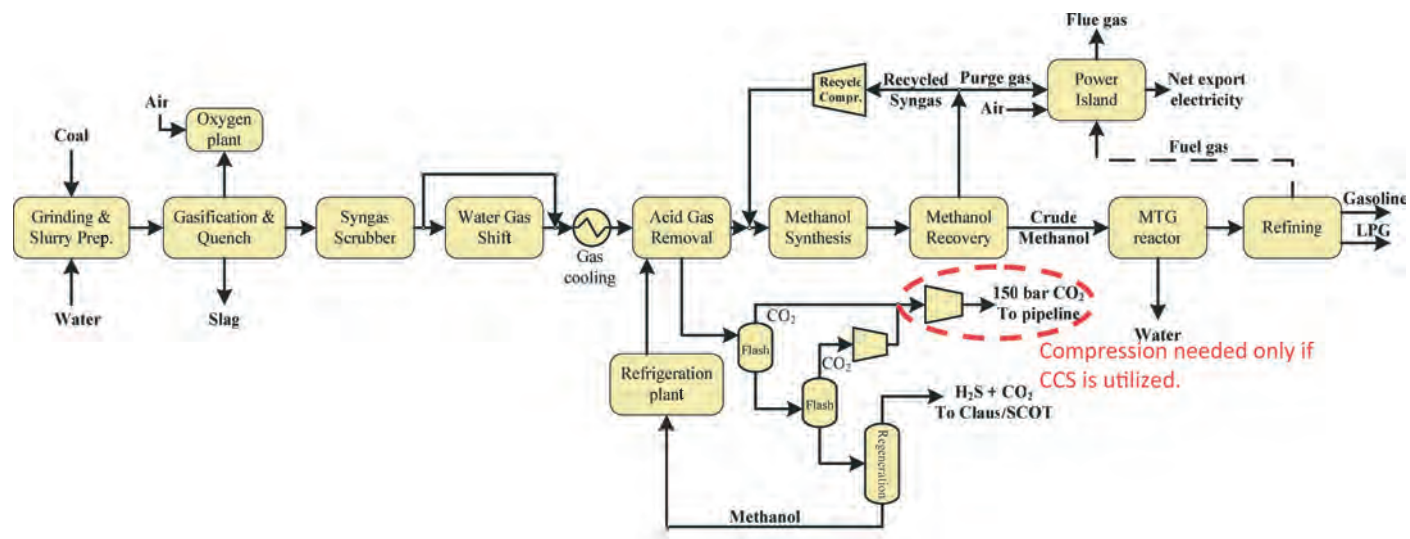

Figure 12.21 | Plant configurations for maximizing gasoline output with only coal as input feedstock.

unconverted syngas can be used to increase electricity generation and provide an exportable electricity co-product.)

More detailed process depictions of coal conversion into F-T fuels are shown in Figure 12.20 (blue and yellow shading). Figure 12.21 shows coal conversion to synthetic gasoline. In these particular plant designs, a slurry of bituminous coal and water is fed into a pressurized gasifier along with oxygen from a dedicated onsite cryogenic air separation unit. The syngas leaving the gasifier is wet-scrubbed before some of it enters a water gas shift reactor. The fraction of the syngas sent to the WGS reactor is adjusted to ensure an appropriate H_2:CO ratio for the later synthesis reactor. Following the WGS reactor, the syngas is cooled in preparation for acid gas removal and, in the case of F-T production, expanded to near the pressure required

for later synthesis. CO_2 and H_2S are then removed by the acid gas removal system. Several acid gas removal technologies are commercially available (see Chapter 13). A physical absorption process using chilled methanol (e.g., Rectisol®) is indicated in Figures 12.20 and 12.21. The captured H_2S is processed via a Claus/SCOT system into elemental sulfur. The captured CO_2 can be either vented to the atmosphere or compressed to a supercritical state for pipeline delivery and underground injection for storage. Following acid gas removal, the syngas is delivered to the synthesis reactor.

In the case of F-T synthesis (Figure 12.20) most of the syngas passes to the synthesis reactor, where it reacts over a catalyst to produce a mixture of olefinic and paraffinic hydrocarbons. When an iron-based synthesis catalyst is used, the syngas H_2:CO ratio entering the reactor

is about one, and the raw liquid product is a mix of hydrocarbons with a wide range of carbon numbers. With a cobalt-based catalyst, the ratio is about two, and the liquid product is largely heavy hydrocarbons (waxes). After synthesis, unconverted syngas and light gases generated during synthesis are recycled back to the synthesis reactor to increase F-T liquids production. (In some situations, separation for sale of the light components that constitute LPG may be economic.) The recycled gases undergo ATR to convert light hydrocarbons, resulting in a stream returning to the synthesis reactor that consists primarily of CO, H_2, and CO_2. A small portion of the recycle gases are drawn off as a purge stream to avoid the buildup of inert gases in the recycle loop. The purge gases are mixed with light hydrocarbons produced in the F-T refining area, and the mixture of gases is burned in the boiler of a steam turbine power system. Electricity production is primarily to meet onsite needs.

The final step in FTL production is refining of the raw liquid product (mostly a crude diesel and naphtha). Hydrogen addition is typically required in this step. In the design shown in Figure 12.20, some syngas is diverted upstream of synthesis for use in producing the requisite hydrogen. A minimum refining step is required to stabilize the liquid products if they are to be shipped to a conventional refinery for further refining. This minimum step includes hydrogenation of the naphtha and diesel range hydrocarbons and hydrocracking of the heavier hydrocarbons (waxes). Alternatively, further refining to finished diesel and gasoline blendstocks can be done onsite. Reforming of the naphtha fraction is required in this case to produce an acceptable gasoline blendstock (Liu et al., 2011a; Guo et al., 2011). The naphtha could be sold instead as a chemical feedstock, thereby avoiding added cost and energy expenditures for catalytic reforming, but chemical markets for naphtha are relatively small (compared to gasoline markets), so this would be a limited option if FTL production were to become widespread.

In the particular process shown in Figure 12.21 for making synthetic gasoline via methanol (MTG) from syngas, the first step following acid gas removal is methanol synthesis, for which the requisite syngas H_2:CO ratio is about two and optimal pressure is 50–100 bar (considerably higher than for F-T synthesis). Most of the unconverted syngas is recycled to increase methanol production, with a small purge stream extracted to avoid building up inert gases. (No reformer is required in the recycle loop as in the FTL design, since there is no significant hydrocarbon content in this stream.) The crude liquid methanol is vaporized and sent to a DME reactor, where it is catalytically converted to an equilibrium mixture of methanol, dimethyl ether and water. The mixture flows to the MTG reactor, where most of the gas is converted in a single pass over a catalyst into gasoline-range hydrocarbons. Some propane/butane (LPG) and a small amount of methane are coproducts. The liquid products are sent for fractionation and finishing (primarily durene treatment), resulting in finished gasoline and LPG products. The purge gas from the methanol synthesis area and light gases evolved in the MTG area fuel the power island, where a steam cycle generates all the electricity needed to run the facility plus a modest amount of export electricity.

Process designs for making FTL or MTG from biomass feedstocks would be similar to those described above for coal conversion. Figure 12.20 shows a configuration for FTL from biomass (BTL) (green plus yellow shading). There are important differences from the coal design (also shown in Figure 12.20): (i) a pressurized fluidized-bed gasifier, which avoids the energy-intensive grinding of biomass that is required with an entrained flow gasifier and enables ash to be removed as a dry material that might be returned to the field for its inorganic nutrient content; (ii) a tar cracking step following gasification to convert into light gases the heavy hydrocarbons that form at typical biomass gasification temperatures (which are lower than coal gasification temperatures) and that would otherwise condense and cause operating difficulties downstream; (iii) reforming of the recycle stream in the MTG design due in part to the higher methane production from biomass gasification compared to coal gasification.

As noted earlier, shortcomings of the BTL option include high feedstock costs and steep scale economies for the plant capital cost. These challenges can be mitigated by coprocessing some biomass with coal (CBTL) (Blades et al., 2008; Tarka et al., 2009; Liu et al., 2011a). Figure 12.20 (all colors of shading) shows a detailed design for a coal/biomass coprocessing system to make FTL fuels (CBTL) utilizing separate coal and biomass gasifiers. With different downstream processing steps, synthetic gasoline could similarly be produced from coal and biomass (CBTG).

12.4.3.2   Performance Estimates

Results from a set of detailed and self-consistent designs and performance simulations of coal and/or biomass conversion to FTL and MTG transportation fuels are presented in Table 12.15. (Illinois #6 bituminous is the coal type, and switchgrass is the biomass type.) The simulations utilize design assumptions for each unit operation (gasification, water gas shift, acid gas removal, FTL synthesis, MTG synthesis, etc.) that are consistent with performance that has been demonstrated in existing commercial applications for all except biomass gasification/tar cracking. For the latter, design assumptions are based on pilot-plant performance. The greenhouse gas emissions estimates include net life cycle emissions for synfuel production and consumption, including emissions associated with activities upstream of the conversion plant, such as coal mining and biomass growing, harvesting, and transportation, as well as emissions downstream of the plant, including transport of the liquid products to refueling stations and combustion of the fuels in vehicles. The process of making synthetic gasoline has some efficiency benefit. For systems using only coal as feedstock and producing liquid fuels at a rate of 50,000 petroleum-fuel-equivalent barrels per day of liquids, Table 12.15 indicates that when making synthetic gasoline (MTG) more of the input coal is converted to liquid fuel (and less to electricity) than for the FTL designs considered here. The result is an overall efficiency advantage of about 5 percentage points for MTG due to the intrinsically higher thermodynamic efficiency of converting syngas to liquids compared to converting it to electricity. There is only

Table 12.15 | Performance estimates for conversion of coal, biomass, and coal + biomass to FTL or MTG.

Process configuration >>>	CTL-RC-V	CTL-RC-CCS	CTG-RC-V	CTG-RC-CCS	BTL-RC-V	BTL-RC-CCS	BTG-RC-V	BTG-RC-CCS	CBTL-RC-CCS	CBTG-RC-CCS
Coal input rate										
As-received, metric t/day	24,087	24,087	20,869	20,869	–	–	0	0	2562	2489
Coal, MW HHV	7559	7559	6549	6,549	–	–	0	0	804	781
Biomass input rate										
As-received metric t/day	0	0	0	0	3581	3581	3581	3581	3581	3581
Biomass, MW HHV	0	0	0	0	661	661	661	661	661	661
% biomass HHV basis	0	0	0	0	100	100	100	100	45	46
Liquid production capacities										
LPG, MW LHV	–	–	309	309	–	–	28	28	–	69
Diesel and/or Gasoline, MW LHV[a]	3159	3159	2913	2913	286	286	270	270	622	610
bbl/day crude oil products displaced (excl. LPG)	50,000	50,000	50,000	50,000	4521	4521	4630	4630	9845	10476
Electricity										
Gross production, MW	849	849	545	545	77	77	78	78	157	145
On-site consumption, MW	445	555	419	509	35	46	46	58	104	134
Net exports, MW	404	295	126	36	42	31	32	20	53	11
ENERGY RATIOS										
Liquid fuels out (HHV)/Energy in (HHV basis)	45.0%	45.0%	52.8%	52.8%	46.5%	46.5%	48.4%	48.4%	45.7%	50.2%
Net electricity/Energy in (HHV)	5.3%	3.9%	1.9%	0.6%	6.4%	4.7%	4.9%	3.1%	3.6%	0.7%
Total products (HHV)+ electricity/ Energy in (HHV)	50.3%	48.8%	54.7%	53.4%	52.9%	51.2%	53.3%	51.5%	49.3%	51.0%
CARBON ACCOUNTING										
C input as feedstock, kgC/sec	178	178	154	154	17	17	17	17	35	35
C stored as CO_2, % of feedstock C	0	52	0	49	0	56	0	60	54	54
C in char (unburned), % of feedstock C	4.0	4.0	4.0	4.0	3.0	3.0	3.0	3.0	3.5	3.5
C vented to atmosphere, % of feedstock C	51.6	10.3	56.9	8.2	63.9	8.2	63.4	3.8	9.0	6.7
C in liquid fuels, % of feedstock C	34.1	34.1	39.1	39.1	33.1	33.1	33.7	33.7	33.7	36.1
C stored, 10^6 tCO_2/yr (at 90% capacity)	0	9.54	0	7.80	0	0.96	0	1.03	1.98	1.95
Lifecycle GHG emissions, kgCO$_2$-eq/GJ liquid fuels LHV[b]	207	101	195	100	7.9	−110	8.5	−125	3.2	1.9
GHGI[c]	1.71	0.89	1.76	0.97	0.063	− 0.95	0.066	− 1.07	0.029	0.018

a Finished diesel and gasoline for FTL cases (63.5% and 36.5% on LHV basis). Finished gasoline in the MTG case.

b If all emissions are charged to gasoline and/or diesel fuels.

c GHGI, the greenhouse gas emissions index, is the system wide life cycle GHG emissions for production and consumption of the energy products relative to emissions from a reference system producing the same amount of liquid fuels and electricity. For FTL systems, the reference liquid fuels are a mix of gasoline and diesel from crude oil for which the average GHG emission rate is 91.6 kgCO$_2$-eq/GJ$_{LHV}$. For MTG systems the reference liquid fuels are gasoline and LPG having life cycle GHG emission rates of 91.3 kgCO$_2$-eq/GJ$_{LHV}$ and 86.0 kgCO$_2$-eq/GJ$_{LHV}$, respectively. In all cases the reference system electricity is assumed to be from a new supercritical pulverized coal power plant for which the average GHG emissions rate is 830.5 kgCO$_2$-eq/MWh$_e$.

Source: Liu et al., 2011a; Liu et al., forthcoming.

about 1.5 percentage points penalty in efficiency (with either MTG or FTL) when CCS is added. The penalty is primarily due to the added electricity needed onsite to compress the captured CO_2 for transport and injection underground.

For systems described in Table 12.15 that use biomass it is assumed that the total biomass input is 1 Mt/yr (dry basis), a practical limit on the biomass delivery rate. For pure biomass systems (see Figure 12.20), this implies a liquid fuel production capacity of 4500–4600 bbl/day. The

overall efficiency for the biomass FTL design is modestly higher than that for the coal-FTL plant. For the MTG plant, however, the efficiency is lower than for the coal-only design due to the syngas compression required in the biomass design to raise the pressure of the syngas to that needed for methanol synthesis. (The gasification pressure is higher for coal than for biomass, so no syngas compressor is required in the coal-to-gasoline designs.) The need for reforming in the recycle loop also contributes to the reduced efficiency for biomass conversion to MTG relative to coal.

The carbon mitigation performance of alternative options is indicated by a greenhouse gas emissions index (GHGI), the system wide life cycle GHG emissions relative to emissions from a reference system producing the same amount of fuels and electricity. It is assumed that the reference system consists of equivalent crude oil-derived liquid fuels and electricity from a new stand-alone supercritical pulverized coal power plant venting CO_2. The GHGI for each option is listed at the bottom of Table 12.15 and
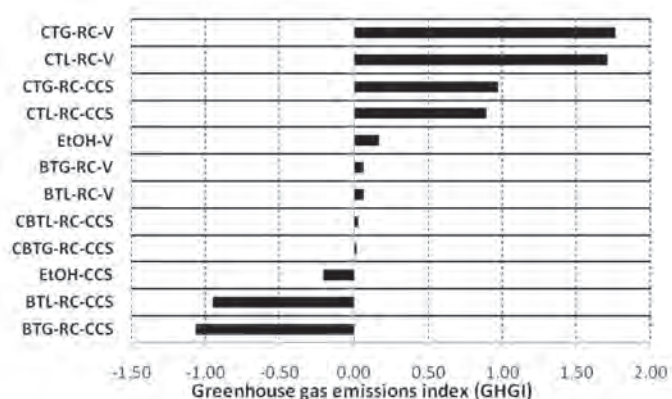

Figure 12.22 | Values of GHGI for the synthetic fuel options described in Table 12.15, along with the GHGI for future cellulosic-biomass ethanol technologies. See Table 12.15, note (c) for definition of GHGI. For details on the cellulosic ethanol options see Box 12.3 and Liu et al., 2011a.

summarized in Figure 12.22. For coal conversion to FTL or MTG without capture of CO_2, GHGI is 1.7 to 1.8 and GHGI is 0.9 to 1.0 with CCS. For biomass conversion, fuel cycle GHG emissions are < 0.07 when CO_2 is vented and strongly negative when CO_2 is captured and stored. For the designs coprocessing coal and biomass (see Figure 12.20), a mix (about 55% coal and 45% biomass, HHV basis) is chosen so that GHGI < 0.1. This GHGI constraint and the assumption of a biomass processing rate of 1 Mt/yr dry biomass imply that the liquid fuel production capacity is about 10,000 bbl/day in the CBTL and CBTG designs.

Biomass is a relatively scarce resource and the only carbon-bearing renewable energy source. Thus, the effectiveness of its use is an important consideration. Figure 12.23 shows one measure of effectiveness: liters of low/zero-GHG gasoline-equivalent FTL or MTG fuel produced per dry tonne of biomass consumed. Shown for comparison is an estimate for future cellulosic ethanol (EtOH) made (without and with CCS) from switchgrass biomass via enzymatic hydrolysis. Not surprisingly, with the FTL and MTG systems that coprocess coal and biomass, the total liquid fuel produced per unit of biomass input is high (because of the coal coprocessing). In the case of pure biomass FTL and MTG and EtOH systems with CCS, it is assumed that the negative GHG emissions provide "room in the atmosphere" for using some conventional crude oil-derived fuels while maintaining overall zero net GHG emissions. The total low-C liquid fuel yields for the cellulosic ethanol production options would be comparable to the biomass-only FTL and MTG systems that vent CO_2 but less than half the yields of low carbon fuels realized for all FTL and MTG systems with CCS.

12.4.3.3   Cost Estimates

For each of the plant designs described in Table 12.15, cost estimates are given in Table 12.16. Costs are reported here in US$_{2007}$$ as discussed in Section 12.2.2.3.
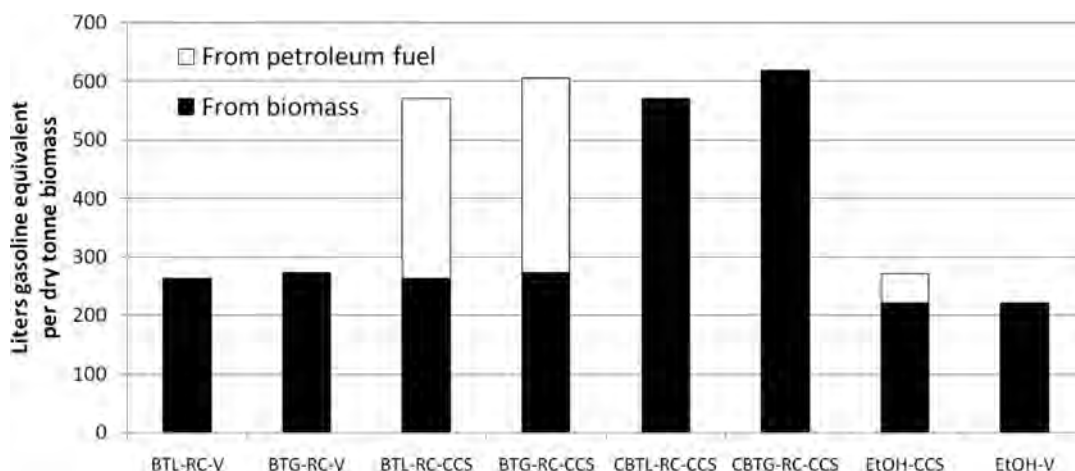

Figure 12.23 | Yields of low/zero net GHG emitting liquid fuels from biomass, liters of gasoline equivalent per dry tonne. For the biomass-only designs that incorporate CCS (BTL-RC-CCS, BTG-RC-CCS, and EtOH-CCS), life cycle GHG emissions are negative, leaving "room in the atmosphere" for some crude oil-derived fuel that can be used while keeping zero net GHG emissions for the biomass + crude oil-derived liquid fuels. Based on Liu et al., 2011a. See also Box 12.3 for a discussion of the cellulosic ethanol options.

Table 12.16 | Capital cost and production cost estimates (US$_{2007}$$) for conversion of coal, biomass, and coal+biomass to FTL or MTG.

Process configuration >>>	CTL-RC-V	CTL-RC-CCS	CTG-RC-V	CTG-RC-CCS	BTL-RC-V	BTL-RC-CCS	BTG-RC-V	BTG-RC-CCS	CBTL-RC-CCS	CBTG-RC-CCS
Coal input rate, MW HHV	7559	7559	6549	6549	–	–	0	0	804	781
Biomass input rate, MW HHV	0	0	0	0	661	661	661	661	661	661
Diesel and/or gasoline production, MW LHV	3159	3159	2913	2913	286	286	270	270	622	610
bbl/day crude oil products displaced, excl LPG	50,000	50,000	50,000	50,000	4521	4521	4630	4630	9845	10,476
Co-product LPG, MW LHV	–	–	309	309	–	–	28	28	–	69
Net export to grid, MW	404	295	126	36	42	31	32	20	53	11
Plant capital costs, million US2007$										
Air separation+ O_2 and N_2 compression	808	808	645	645	100	100	109	109	208	211
Biomass handling, gasification, and gas cleanup	0	0	0	0	336	336	340	340	335	347
Coal handling, gasification, and quench	1468	1468	1301	1301	0	0	0	0	226	189
water gas shift, acid gas removal, Claus/SCOT	849	849	589	598	59	59	89	89	158	162
CO_2 compression	0	67	0	59	2	14	2	14	22	22
F-T synthesis & refining or methanol synthesis	882	882	506	506	137	137	89	89	244	147
Naptha upgrading or MTG synthesis & refining	86	86	526	526	21	21	80	80	33	141
Power island topping cycle	35	27	0	0	0	0	0	0	7	0
Heat recovery and steam cycle	723	0	470	470	69	69	86	86	136	135
Total plant cost (TPC), million US$_{2007}$$	4852	4919	4038	4105	724	737	794	806	1369	1354
Specific TPC, US$_{2007}$$/bbl/day	97,033	98,372	80,757	82,099	160,189	162,927	171,520	174,131	139,091	129,200
Liquids production cost, US$_{2007}$$/GJ$_{LHV}$ (with zero GHG emissions price)[a]										
Capital charges (at 14.38% of Total Plant Inv., TPI)	8.34	8.45	7.52	7.65	13.77	14.00	15.97	16.22	11.95	12.03
O&M charges (at 4% of TPC/year)	2.16	2.19	1.95	1.98	3.57	3.63	4.15	4.21	3.10	3.12
Coal (at 2.04 US$/GJ$_{HHV}$, 55 US$/t, as-received)	4.87	4.87	4.58	4.58	0.00	0.00	0.00	0.00	2.63	2.60
Biomass (at 5 US$/GJ$_{HHV}$,94US$/t, dry)	0	0	0	0	11.56	11.56	12.24	12.24	5.31	5.41
CO_2 emissions charge	0	0	0	0	0	0	0	0	0	0
CO_2 disposal charges	0	0.52	0	0.46	0	1.38	0	1.41	0.94	0.90
Coproduct electricity (at 60 US$/MWh)	–2.13	–1.56	–0.72	–0.21	–2.46	–1.81	–1.98	–1.26	–1.42	–0.29
Co-product LPG revenue (at 100 US$/bbl)	–	–	–2.19	–2.19	–	–	–2.16	–2.16	–	–2.16
Total, US$_{2007}$$/GJ LHV	**13.24**	**14.48**	**11.14**	**12.27**	**26.44**	**28.76**	**28.22**	**30.67**	**22.51**	**21.62**
Total, US$_{2007}$$/gallon gasoline equivalent	1.59	1.74	1.33	1.47	3.17	3.45	3.38	3.68	2.70	2.59
Breakeven oil price, US$_{2007}$$/bbl[b]	61	67	48	53	133	145	126	137	111	96
Cost of avoided CO_2, US$_{2007}$$/t	–	12.4	–	12.8	–	20.9	–	19.3	16.9	29.4

a See note (b) of Table 12.6 for financial parameter assumptions.

b The breakeven oil price (BEOP) is calculated assuming the LPG co-product is sold for its wholesale price assuming the crude oil price is US$100/bbl. The wholesale price of LPG is determined as a function of crude oil price from a regression correlation of wholesale propane prices and refiner crude oil acquisition costs in the United States (propane (US$/bbl) = 0.7212 * Crude acquisition cost (US$/bbl) + 5.2468). See Kreutz et al., 2008 for additional discussion of the BEOP calculation.

Source: Liu et al., 2011a; Liu et al., forthcoming.

Specific capital costs for coal conversion without CCS range from US$81,000 per bbl/day to US$98,000 per bbl/day. Adding CCS involves a relatively small cost increment, since the primary additional cost is equipment for CO_2 compression. Specific costs for biomass conversion are considerably higher due largely to the much smaller scale of the conversion facility. Systems coprocessing coal and biomass are larger in scale than biomass-only systems, but smaller than the coal-only systems, which largely accounts for the intermediate level of specific capital costs.

Table 12.16 also shows both the levelized cost of fuel (LCOF) production and the crude oil price at which the FTL and MTG fuels would compete with petroleum-derived fuels when the price of GHG emissions is zero. For the coal-only plants, capital charges are the most significant production cost component, while for biomass-only facilities capital and feedstock are of comparable importance. For systems that vent CO_2 the breakeven oil price (BEOP) is in the range US$48–61/bbl for coal plants and US$126–133/bbl for biomass plants. For systems with CCS the BEOP is in the range

US$53–67/bbl for coal plants, US$137–145/bbl for biomass plants, and US$96–111/bbl for plants that coprocess coal and biomass.

As shown in Figure 12.24, when non-zero GHG emissions prices are considered, the relative economics of alternative process designs can be considerably different from those in Table 12.16. At GHG emission prices above a modest US$10–20/tCO$_2$-eq the –CCS variant of each option realizes a lower BEOP than the –V variant because the cost of CO_2 capture is low as a result of the production of a by-product stream of pure CO_2 as an intrinsic part of the design of gasification-based liquid fuels production. At GHG emission prices above US$65–75/tCO$_2$-eq the biomass –CCS option realizes a lower BEOP than the corresponding coal –CCS option (with more than 10 times the output capacity), as a result of the strong negative GHG emission rates for the biomass with –CCS options.

12.4.4   Hydrogen from Non-petroleum Feedstocks for Transportation

Hydrogen production from fossil fuels, the subject of this section, is well-established commercially in petroleum refining, ammonia production, and other industries where hydrogen is needed as a chemical feedstock.

H_2 produced electrolytically from non-carbon energy sources (wind, solar) is more costly than projected costs of making H_2 with ultra-low GHG emissions from coal or natural gas with CCS (Williams, 2002). The higher cost is largely because electricity purchases account for the largest share of total H_2 production costs with electrolysis. Wind and solar electricity are still more expensive than fossil fuel electricity today, despite reductions in costs for wind or solar electricity and escalations in

costs for construction of fossil energy conversion facilities. A key point is that electrolytic H_2 could plausibly be competitive as a transportation fuel (via use in fuel cell vehicles) only if offpeak/low-cost electricity (regardless of source) is used to make H_2. But only a tiny fraction of transportation fuel demand (which globally is 1.6 times electricity generation) could be satisfied with H_2 from offpeak electricity (a small fraction of total electricity).

Hydrogen is not used as a transportation fuel today, but its attractions in this application include the potential for low emissions of local pollutants and of greenhouse gases, as well as the energy security benefits arising from being able to shift transportation from oil dependence. Such attractions have made research on distribution and end-use systems for H_2 as a transportation fuel the focus of important government research and development programs in the United States, China, and elsewhere beginning in the 1990s. However, these R&D efforts have brought recognition that there are still major challenges to be overcome in H_2 delivery infrastructure and end use before it can become a real option for the transportation sector (CASFHPU, 2004; Agnolucci, 2007; CARNFCHT, 2008). Here we limit our discussion to a review of technologies for hydrogen production.

Globally, natural gas is the most commonly used feedstock for hydrogen production (Consonni and Vigano, 2005; Rostrup-Nielsen, 2005), but hydrogen can also be made from coal (Chiesa et al., 2005; Kreutz et al., 2005), as is the predominant commercial practice in China. Hydrogen can also be produced from biomass in systems closely resembling those for coal conversion (Hamelinck and Faaij, 2002; Lau et al., 2002).

Figure 12.25 shows a simplified block flow diagram for hydrogen production from coal. Gasification technologies for production of CO and H_2-rich synthesis gas from coal and biomass have been discussed in Section
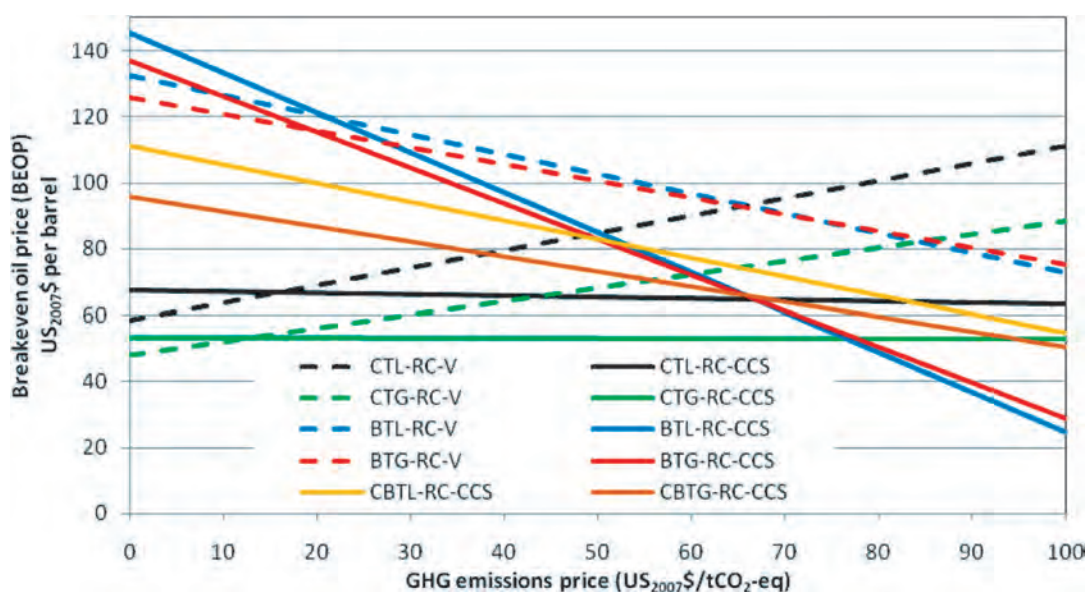

Figure 12.24 | Breakeven oil prices (US$_{2007}$$) as a function of GHG emission price for coal, biomass, and coal/biomass conversion to FTL or MTG. (See Table 12.6, note (b) for financial parameter assumptions. Also, electricity sales are assumed at the US average grid price plotted in Figure 12.10.)
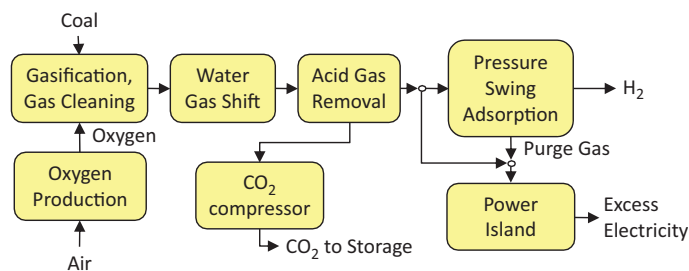
Figure 12.25 | Simplified process diagram for H$_2$ production from coal with CO$_2$ capture.

Figure 12.26 | Simplified process diagrams for H$_2$ production from natural gas via steam-methane reforming (top) or via autothermal reforming (bottom). When CO$_2$ is captured for storage (as shown), import of electricity may be required to meet on-site needs. Without CO$_2$ capture, there can be net electricity exports to the grid from the facility.

12.4.3.1. Gasification is followed by a water gas shift, after which sulfur species are removed to prevent poisoning of downstream catalysts. This presents a natural point for also removing CO$_2$ with little added capital cost. Acid gas removal using a physical solvent (e.g., methanol, as in the Rectisol process) would typically be used because of the elevated pressure of the gas mixture containing the acid gases. The captured sulfur is recovered from the solvent and converted, for sale or disposal, to elemental sulfur using the Claus/SCOT process. The captured CO$_2$ can be compressed for pipeline transport to an underground storage site. Following acid gas removal, the remaining hydrogen-rich stream is concentrated using pressure swing adsorption (PSA) technology to purity as high as 99.999%. Purge gases from the PSA, supplemented as needed by some syngas bypassing the PSA, are burned in the power island to provide the electricity needs of the plant and additional exportable power.

For hydrogen production from natural gas (Figure 12.26), syngas can be produced using any of several different reforming technologies (Rostrup-Nielsen and Rostrup-Nielsen, 2002). The two most common, SMR and ATR, have been discussed in Section 12.4.1.1. With natural gas conversion based on SMR (Figure 12.26, top), sulfur removal is not needed following the water gas shift, since any sulfur present in the methane input to the plant has been removed prior to the SMR to avoid poisoning the SMR catalyst. If CO$_2$ is to be captured for storage, this would most effectively be accomplished using an acid gas removal system on the flue gases from the power island and the reformer furnace. This design enables maximum CO$_2$ capture, because all flue gases are collected before CO$_2$ removal. However, the low-pressure of the CO$_2$ in the flue gases requires using a chemical solvent (such as MEA) to effectively capture the CO$_2$. The work to subsequently compress the captured CO$_2$ for pipeline transport will be higher than in the systems producing hydrogen using ATR, for which the CO$_2$ is available at a higher starting pressure. For a system using ATR (Figure 12.26, bottom), capture of CO$_2$ would take place after the water gas shift using a physical solvent, such as Rectisol.

Table 12.17 summarizes comparative mass and energy balance simulation results developed for this chapter for hydrogen production. It is based on detailed system designs represented in simplified form in Figures 12.25 and 12.26. For designs that capture CO$_2$, the overall energy efficiency of coproducing hydrogen and electricity is 67% with coal and 74% with natural gas. The efficiency penalty for systems that
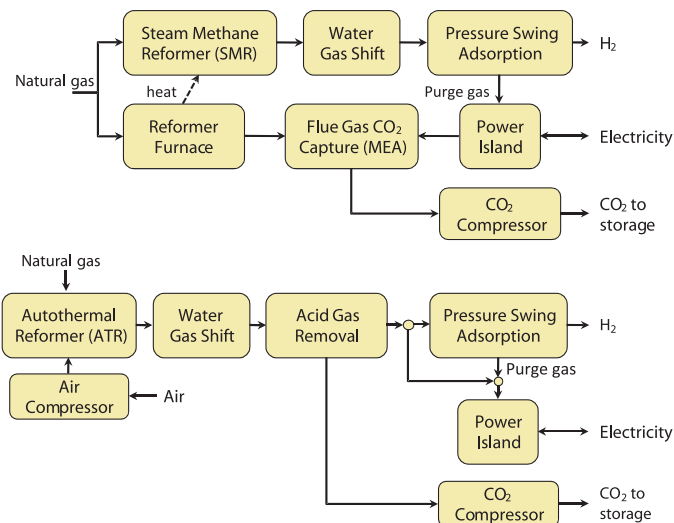
capture CO$_2$ compared with systems that vent the CO$_2$ is largest for the natural gas case using SMR (Figure 12.26, upper). This is due to the substantial heat required to liberate the dissolved CO$_2$ from the solvent used to capture it. The heat is provided as steam extracted from the power island, which reduces the on-site power generation significantly. Natural gas conversion using the ATR also requires some net import of electricity due to the substantial power requirements for air separation and CO$_2$ compression.

Capital and operating cost estimates for the systems described in Table 12.17 are provided in Table 12.18 using the same framework and component capital cost database as for systems described in Sections 12.4.3 and 12.6. Hydrogen production costs using natural gas, despite the considerably lower capital cost intensity compared with coal designs, are nevertheless higher than for coal due to the much higher assumed feedstock prices. Production costs with natural gas are also higher in the CCS cases due to the need to purchase electricity to operate the facility rather than selling excess electricity to the grid.

The final row of Table 12.18 shows the avoided cost of CO$_2$ emissions when CCS is considered. The avoided cost for coal is modest (US$11/tCO$_2$-eq) because capturing the CO$_2$ at these plants involves only adding a CO$_2$ compressor. The situation is similar for the natural gas system using ATR, but the avoided CO$_2$ cost is higher than for a coal-CCS design of comparable scale because the added cost includes that for acid-gas capture in addition to a CO$_2$ compressor. (The cost for acid gas removal is modest because only half as much CO$_2$ must be captured as in the coal case due to the lower carbon intensity of natural gas.) In the SMR design for natural gas, costs for the added equipment to capture dilute CO$_2$ from flue gases and compress it are charged against the CO$_2$, leading to relatively higher avoided costs.

Table 12.17 | Mass and energy balances for hydrogen production for different feedstocks.

Feedstock >>>	Coal[a]		N. gas – SMR[b]		N. gas – ATR[b]	
CO₂ vented or captured >>>	Vent	CCS	Vent	CCS	Vent	CCS
Power island technology >>>	Combined Cycle		Steam Rankine Cycle			
Coal input, as-received t/day	12,615	12,615				
Coal input, MW HHV	3,817	3,817				
Biomass input, as-received t/day						
Biomass input, MW HHV						
Natural gas input, t/day			5,561	5,561	5,519	5,519
Natural gas input, MW HHV			3,335	3,335	3,310	3,310
Hydrogen Production, MW LHV	2,083	2,083	2,083	2,083	2,083	2,083
Hydrogen Production, MW HHV	2,461	2,461	2,461	2,461	2,462	2,462
Electricity						
Gross production, MW	424.8	424.8	217.5	85.6	262.0	262.0
On-site consumption, MW	272.4	349.2	27.2	103.4	220.4	274.3
Net export to grid, MW	152.4	75.6	190.3	-17.8	41.6	-12.3
ENERGY RATIOS (HHV basis)						
H₂ out / energy in	64.5%	64.5%	73.8%	73.8%	74.4%	74.4%
net electricity / energy in	4.0%	2.0%	5.7%	-1.4%	1.3%	-0.4%
H₂ + electricity / energy in	68.5%	66.5%	79.5%	72.4%	75.6%	74.0%
CARBON ACCOUNTING						
C input as feedstock, kgC/sec	**89.5**	**89.5**	**47.7**	**47.7**	**47.3**	**47.3**
C stored as CO₂, % of feedstock C	0.0	91.2	0.0	90.0	0.0	82.8
C in char (unburned), % of feedstock C	0.8	0.8	0.0	0.0	0.0	0.0
C vented to atmosphere, % of feedstock C	99.2	8.0	100	9.9	100	17.1
C stored, MtCO₂/yr (90% capacity factor)	0.0	8.5	0.0	4.5	0.0	4.1
Lifecycle GHG emissions						
Net emissions, kgCO₂-eq/ GJ H₂ LHV	163	19.1	84.3	10.8	83.6	16.1
GHGI[c]	1.74	0.22	0.86	0.14	1.03	0.21

a Results based on performance simulations of Chiesa et al., 2005.

b Results based on performance simulations of Zhang, 2005.

c GHGI, the greenhouse gas emissions index, is the system wide life cycle GHG emissions for production of H₂ and electricity relative to emissions from a reference system producing the same amount of H₂ and electricity. The reference system consists of large-scale centralized H₂ production by steam reforming of natural gas, with lifecycle emissions of 9.22 kgCO₂-eq/kgH₂ (NRC, 2004), plus electricity from a supercritical pulverized coal power plant with GHG emissions rate of 830.5 kgCO₂-eq/MWhe.

d In the GHGI calculation, net electricity consumed in these process designs is charged 830.5 kgCO₂-eq/MWhe. All other designs in this table have net exports of electricity.

Table 12.18 | Cost estimates (US$_{2007}$$) for hydrogen production systems described by Table 12.17.

Feedstock >>>	Coal		N. gas – SMR		N. gas – ATR	
CO$_2$ vented or captured >>>	Vent	CCS	Vent	CCS	Vent	CCS
Coal input rate, MW HHV	3817	3817				
Biomass input rate, MW HHV						
Natural gas input rate, MW HHV			3335	3335	3310	3310
hydrogen production rate, MW LHV	2083	2083	2083	2083	2083	2083
Net export to grid, MW	152.4	75.6	190.3	-17.8	41.6	-12.3
Plant capital costs, million US$_{2007}$$ [a]						
Air separation unit + O$_2$, N$_2$, air compressor	404	404	0.0	0.0	79	79
Biomass handling, gasification, gas cleanup	0.0	0.0	0.0	0.0	0.0	0.0
Coal handling, gasification, and quench	791	791	0.0	0.0	0.0	0.0
Reforming (SMR or ATR)	0.0	0.0	737	737	244	244
WGS, acid gas removal, Claus/SCOT[b]	581	581	161	161	222	264
MEA system for SMR case (CO$_2$ removal)	0.0	0.0	0.0	135	0.0	0.0
CO$_2$ compression	9.3	62	0.0	48	0.0	38
PSA section (including H$_2$ compression)	83	83	34	34	76	58
Power island topping cycle	62	62	0.0	0.0	0.0	0.0
Heat recovery and steam cycle	139	139	110	79	222	237
Total plant cost (TPC), million US$_{2007}$$	2067	2120	1042	1194	844	920
US$_{2007}$$/kW$_{HHV}$ of input feedstock	542	555	312	358	255	278
Levelized hydrogen cost with no carbon emission price, US$_{2007}$$/GJ LHV[c]						
Capital charges	5.4	5.5	2.7	3.1	2.2	2.4
O&M charges	1.4	1.4	0.7	0.8	0.6	0.6
Coal (at 2.04 US$/GJ, HHV; 55 US$/t, as-rec'd)	3.7	3.7	0.0	0.0	0.0	0.0
Biomass (at 5 US$/GJ, HHV; 93.7 US$/t, dry)	0.0	0.0	0.0	0.0	0.0	0.0
NG (at 5.11 US$/GJ, HHV)	0.0	0.0	8.2	8.2	8.1	8.1
CO$_2$ transportation and storage	0.0	0.7	0.0	0.4	0.0	0.4
Electricity sales or purchase (at 60 US$/MWh)	-1.2	-0.6	-1.5	0.1	-0.3	0.1
Total hydrogen cost, US$_{2007}$$/GJ LHV	9.3	10.8	10.1	12.7	10.6	11.7
Cost of avoided CO$_2$, US$_{2007}$$/tCO$_2$e[d]	–	11	–	47	–	17

a Component costs are based on Liu et al., 2011a, except for: SMR (Simbeck, 2004); ATR (Simbeck and Wilhelm, 2007); MEA system (Kreutz et al., 2005; Woods et al., 2007).

b In the case of N.gas SMR with CCS, only the WGS cost is included in this line since acid gas removal is done via MEA (separate cost line) and no sulfur treatment via Claus/SCOT is needed.

c See note (b) of Table 12.6 for financial parameter assumptions.

d Levelized H$_2$ production cost for system with CCS minus that for system without CCS, divided by the difference in system-wide life cycle emissions of CO$_2$-eq/GJ$_{LHV}$ of H$_2$ (given in Table 12.17).

Figure 12.27 plots hydrogen production costs as a function of the price of greenhouse gas emissions. Coal provides the least costly low-GHG hydrogen (US$10–12/$GJ_{LHV}$) in the system with CCS for a GHG emission price above US$10/$tCO_2$-eq.

An important final comparison is between the costs of hydrogen production with CCS and those for low-GHG liquid fuels. For GHG emission prices from US$0–100/$tCO_2$-eq, the lowest production costs for low-GHG liquid fuels are with systems that coproduce liquids and power (see Section 12.6). Liquid fuel costs from such systems are $US15–17/$GJ_{LHV}$ depending on the GHG emissions price (see Figure 12.36). This is higher than the US$10–12/$GJ_{LHV}$ estimated for hydrogen (Figure 12.27). But use of hydrogen for transportation will require new delivery and refueling infrastructures, as well as new vehicle technologies, unlike for petroleum-like liquid fuels.

Cost estimates in the literature for new infrastructure in the United States delivering H_2 from centralized production facilities to vehicle fuel tanks are much higher than for new infrastructure for liquid fuels. Published hydrogen infrastructure cost estimates include $US_{2007}$$14–16/GJ_{LHV} (Ogden et al., 2004), $US_{2007}$$9–20/GJ_{LHV} (Mintz et al., 2002), and $US_{2007}$$44/GJ_{LHV} (Simbeck, 2003). Compared to these costs, the new-infrastructure costs for delivery of liquid fuels, particularly petroleum-like fuels, would be small. Moreover, in the industrialized countries, the investment in a full liquid fuel infrastructure has already been made. Thus, when production and delivery infrastructure costs are considered together, delivered hydrogen costs would be significantly higher than delivered costs for liquid fuels.

Beyond questions around fuel delivery infrastructure, it remains uncertain when the cost of hydrogen fuel cell vehicles, which have been the focus of considerable development efforts over the past two decades, can be reduced to competitive levels. One study (IEA, 2009a) estimates that in the near term the GHG emissions price needed to induce by market forces a shift to hybrid fuel cell vehicles is more than US$1000/$tCO_2$-eq when the crude oil price is US$60/bbl and almost US$800/t with US$120/bbl of crude oil. The major technical challenges for fuel cell vehicles are difficulties of onboard H_2 storage due to its low volumetric energy density and high projected costs for fuel cell engines (in part due to platinum requirements). These challenges may not be insurmountable, but overcoming them will require time and sustained large government investments in R&D (CARNFCHT, 2008).[12] Thus, it is likely to be many decades before H_2 fuel cell vehicles will be in a position to make significant contributions toward reducing GHG emissions.
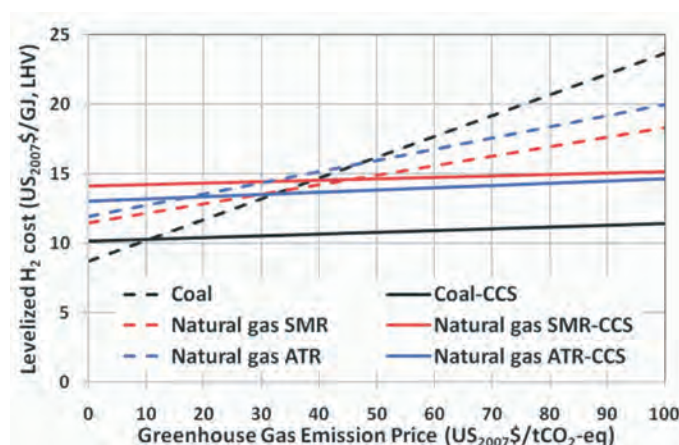

Figure 12.27 | Levelized hydrogen production costs as a function of GHG emissions price. (See Table 12.6, note (b) for financial parameter assumptions. Also, electricity sales are assumed at the US average grid price plotted in Figure 12.10.) Source: based on Simbeck, 2004; Simbeck and Wilhelm, 2007; Liu et al., 2011a.

12.5 Clean Household Fuels Derived from Non-petroleum Feedstocks

Studies have shown that human welfare, as measured by the Human Development Index (HDI), increases with diminishing returns as the level of modern energy services provided increases (WEA, 2004). The HDI increase is especially large for provision of the first increments of modern energy carriers to satisfy basic needs such as cooking and heating, for which demand is very inelastic (cooking and boiling water are essential for survival). There is wide recognition of the importance of the role that electricity plays in economic development and the fact that more than a billion people do not have access even to the minimal amounts of electricity required to satisfy basic needs. Similarly, it is recognized that there are nearly three billion people who cook their food today using traditional open fires inside their homes, suffering considerable health damages in the process (see Hutton et al., 2006 and Chapters 4, 17, and 19).

Fluid hydrocarbon fuels offer a much cleaner means of providing cooking services than solid fuels (Smith, 2002). Moreover, fluid fuels enable much higher efficiency (Dutt and Ravindranath, 1993) and controllability than cooking with solid fuels.[13] Historical real data confirm the gains from efficiency and controllability (Figure 12.28). Such gains along with consideration that a shift to cooking with clean fuels leads to demands on a global basis that are relatively small compared to energy demands for other purposes, means that a relatively small amount of fluid fuel would be sufficient to replace all current solid fuel used for cooking.

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12 Waning enthusiasm for addressing these challenges was evident in the Obama Administration's proposed 2010 Department of Energy (DOE) budget, which included a cut in the federal hydrogen fuel cell research and deployment budget by more than two thirds, eliminating funds for the H_2 fuel cell vehicle program and market transformation programs.

13 Consider LPG stoves. Not only are they much more energy-efficient than biomass stoves, but also an LPG stove can be instantly turned on and off with the demand for cooking services, whereas a biomass stove must be started up long before cooking begins and continue burning long after cooking stops. Of course, the continued burning of biomass after a meal is cooked in the evening may often be for lighting. This implies that, if LPG is to be substituted for biomass for cooking, this cooking fuel switch should often be accompanied by the introduction of alternative means for lighting.
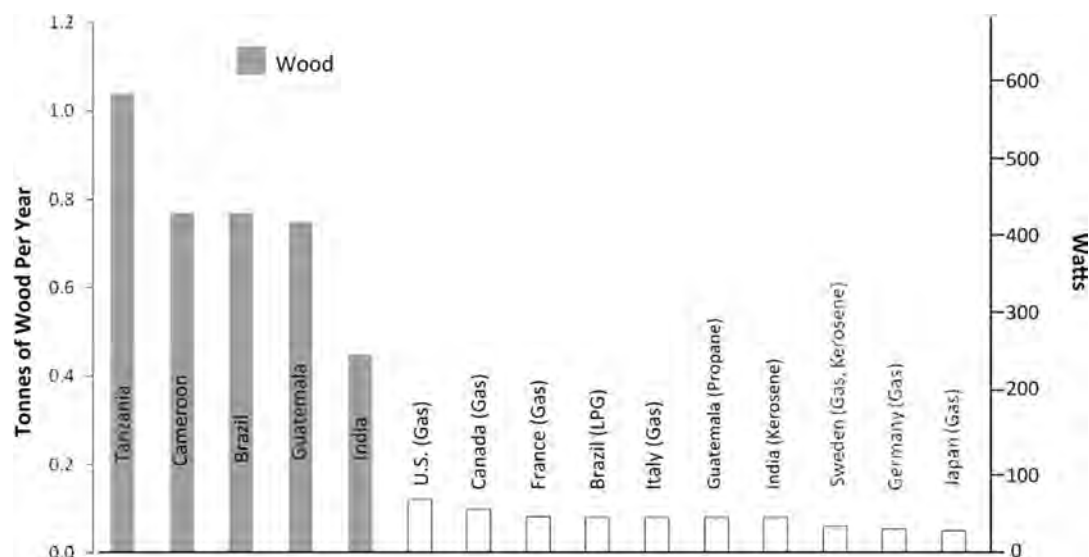
Figure 12.28 | Per capita energy use rate for cooking in the early 1980s. For both wood stoves and stoves burning high-quality energy carriers, the per capita energy use rate is in Watts; for wood fuel, the rate is also in t/yr of dry wood. (Assuming 1 tonne = 18 GJ, 1 t/yr = 570 Watts). Source: Goldemberg et al., 1985.

For perspective, suppose that all three billion people currently using solid fuels for cooking were instead to use liquefied petroleum gas (LPG) at an estimated average needed rate of 25 kg/capita/yr (36 W/capita).[14] The total annual requirement would be 3.4 EJ/yr, or 1.3% of current total global oil and gas consumption.

A shift from solid to fluid fuels for cooking would yield substantial public benefits in terms of improved public health and time saved not spent collecting solid fuels, which would make time available to pursue educational and other opportunities (see Chapter 4). Another benefit would be reduced deforestation, to the extent that some biomass collected for cooking is removed unsustainably from forests.

Such considerations have led to proposals for concerted global efforts to replace solid cooking fuels with clean fluid fuels worldwide (Goldemberg et al., 2004; IEA, 2006; WHO, 2006; GACS, 2011).

Concerns about rising costs of and overdependence on petroleum imports have created interest in alternatives to petroleum-derived fluid cooking fuels such as kerosene and LPG. This section discusses production systems for expanding clean fluid cooking fuel supplies. It considers the use of synthetic fluid fuels (synthetic LPG and DME) derived via gasification of coal and/or biomass, without and with carbon capture and storage. Coal and biomass are the most widely available feedstocks in regions where solid fuels are now used for cooking. DME as a cooking

fuel could also be made from natural gas (Naqvi, 2002). The growing optimism that shale gas might prove to be widely available (see Section 12.7.2.2) suggests also giving close attention to DME derived from natural gas for cooking, though this topic is not covered here.

12.5.1   Dimethyl Ether from Coal

Dimethyl ether is a colorless gas at ambient temperature and pressure, with a slight ethereal odor. It requires mild pressurization, similar to that required for LPG, to be stored as a liquid. It burns with a clean blue flame over a wide range of air/fuel ratios. It can be used as a diesel engine fuel (Semelsberger et al., 2006) or blended with LPG for use as a household or commercial sector fuel. In the latter application, the focus of the discussion here, the DME can be blended up to about 25% by volume without the need to change end-use combustion equipment. Table 12.19 compares some physical properties of DME with those of the two main constituents of LPG.

Until recently, DME was used primarily as an aerosol propellant in hair sprays and other personal care products and was produced globally at a rate of about 150,000 t/yr (Naqvi, 2002).This production level has increased dramatically in the past few years, with the added DME being used primarily as an LPG supplement for household use. The increase has been most substantial in China, where an estimated total DME production capacity of nearly 14 Mt/yr from coal have recently commenced production or construction, and a comparable amount of additional capacity is at various planning, feasibility, or engineering stages (Zheng et al., 2010).

Production of DME from synthesis gas is similar in many respects to synthesis of methanol, a well-established commercial process. In fact, a key step in the synthesis process is catalytic synthesis of methanol, followed

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14   In a spreadsheet accompanying the World Health Organization paper (Hutton et al., 2006) that was made available to the authors, estimates were developed by this WHO group of the LPG that would be required to replace direct use of biomass for cooking in regions throughout the world. Worldwide the average per capita amount of LPG needed annually was estimated to be 24.6 kg, but this rate varies from an average of 14.3 kg for Africa, to 25.6 kg for the region including India, to 29.3 kg for the region including China, to 47.0 kg for the region including Brazil.

Table 12.19 | Physical properties of DME, propane, and butane.

	DME	Propane	Butane
Boiling point (°C)	−24.9	−42.1	−0.5
Vapor pressure ant 20°C (bar)	5.1	8.4	2.1
Liquid density at 20°C (kg/m³)	668	501	610
Lower heating value (MJ/kg)	28.4	46.4	45.7
Auto-ignition temperature at 1 atm pressure (°C)	235 – 350	470	365
Flammability limits in air (vol %)	3.4 – 17	2.1 – 9.4	1.9 – 8.4

Source: Larson and Yang, 2004.

by dehydration of methanol to form DME: $2CH_3OH \leftrightarrow CH_3OCH_3 + H_2O$. Methanol can be synthesized at one plant location and transported to another location where dehydration can be done. This is how most DME has historically been produced. Alternatively, methanol and dehydration plants can be integrated at a single facility. Moreover, technology is now available for a single-step synthesis of DME from syngas: some methanol synthesis catalyst and some dehydration catalyst are used together in the same reactor so that methanol is dehydrated as it forms. The single-step synthesis chemistry can be represented as follows: $3CO + 3H_2 \leftrightarrow CH_3OCH_3 + CO_2$. This approach gives rise to higher yields than the traditional two-step process and so is likely to be the technology of choice in the future.

Figure 12.29 illustrates one possible process arrangement for converting coal to DME. Coal is gasified in oxygen to produce a raw syngas that is cooled and cleaned before having its H_2:CO ratio adjusted in a water-gas-shift reactor (using a sulfur-tolerant catalyst) to an optimum value for subsequent catalytic synthesis of DME. The synthesis step can use a recycle of unconverted gas to increase DME production or a single-pass of the gas through the synthesis reactor ("once-through" design). The unconverted gas can be burned in a gas turbine/steam turbine combined cycle to generate coproduct electricity. Removal of CO_2 is an essential part of the DME production process, since excess CO_2 reduces the efficiency of the downstream synthesis step and would also necessitate larger downstream equipment. The captured CO_2 can be released to the atmosphere or compressed for pipeline transport and underground storage.

Celik et al. (2004), building on work by Larson and Ren (2003), present detailed process designs and production costs for large-scale single-step "once-through" DME synthesis systems starting with coal as the feedstock. Designs with and without CCS were analyzed (Table 12.20). For the design labeled "UCAP" (shorthand for "upstream CO_2 capture"), CO_2 for storage is captured upstream of the DME synthesis area (as depicted in Figure 12.29). Only about 30% of the carbon in the coal feedstock is captured in this case. Nearly 70% of the carbon is released to the atmosphere as flue gas from the power island and when the product DME is burned. For the systems labeled DCAP (shorthand for "downstream plus upstream CO_2 capture"), additional CO_2 is removed by subjecting the unconverted syngas after synthesis to varying levels
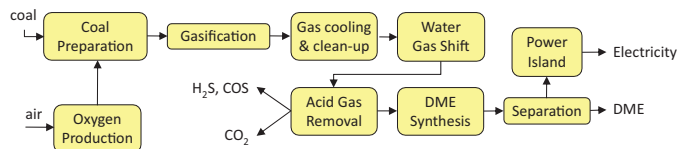
Figure 12.29 | Process steps for DME production from coal.

of water gas shift before the power island. In the case with the highest amount of CO_2 capture (DCAP-3), nearly 80% of the carbon in the coal is captured.

The GHGI, defined in Table 12.20 note (b), without CCS is 1.3. The UCAP design reduces this to 0.94. With more aggressive CCS (DCAP designs), greenhouse gas emissions can be reduced to less than 50% of the reference system emissions. The cost of avoided CO_2 emissions relative to the VENT design are modest for the UCAP case (last row, Table 12.20), since the cost of capture is an intrinsic part of the DME production process regardless of whether CO_2 storage is contemplated. Costs of avoided CO_2 emission are higher for the DCAP designs because the cost for the additional CO_2 capture equipment is fully charged to CO_2 capture.

The added capture equipment also leads to higher DME production costs. For US conditions, with the financial assumptions noted in Table 12.20 (note d), the VENT design produces DME at an estimated cost of US$423/tLPG-eq, corresponding to a breakeven crude oil price (BEOP) of about US$40/bbl. The BEOP is only slightly higher for the UCAP case, but significantly higher for the DCAP cases, reaching US$81/bbl for the DCAP-3 design. Larson and Yang (2004) estimate that costs of DME production in China today might be 15% lower than these estimates for US conditions.

12.5.2   Synthetic LPG from Coal and/or Biomass

Clean cooking fuels can also be produced from coal and/or biomass via the F-T or methanol-to-gasoline processes described in Section 12.4.3. The designs discussed there are for production of synthetic transportation fuels as the primary products, but significant quantities of C3 and C4 hydrocarbons are produced as intermediate or final products. In either system, these lighter hydrocarbons can be separated from the heavier transportation fuel products for sale as synthetic LPG.

For the design of the F-T systems described earlier, it was assumed that the light hydrocarbon fraction was consumed internally as a component of the fuel gas for the power island. Alternatively, the lighter fraction could have been separated as an additional coproduct. The raw synthesis product can contain as much as 20% by weight of C3 and C4 compounds that constitute synthetic LPG.

Table 12.20 | Performance and cost (US$_{2007}$$) estimates for DME production from coal with different levels of CCS. "UCAP" refers to designs with CO_2 removal upstream of DME synthesis (as in Figure 12.29). "DCAP" refers to designs that additionally capture some CO_2 downstream of synthesis. Three alternative downstream capture designs are considered. See Celik et al. (2004) for details.

	No CCS	With varying levels of CO_2 capture			
	Vent	**UCAP**	**DCAP-1**	**DCAP-2**	**DCAP-3**
Coal input, MW LHV	2203	2203	2203	2203	2203
DME output, MW LHV	600	600	600	600	600
Gross power production, MW	628	628	589	590	586
Net power export, MW	490	469	367	365	353
Fraction of coal LHV converted to DME	0.272	0.272	0.272	0.272	0.272
Fraction of coal LHV converted to net power	0.223	0.213	0.167	0.166	0.160
Total efficiency (LHV basis)	49.5	48.5	43.9	43.8	43.2
Plant carbon balance, tC/hr					
Input as coal	199.7	199.7	199.7	199.7	199.7
Buried as char	2.0	2.0	2.0	2.0	2.0
Captured as CO_2	0	57.5	143.5	147.6	156.4
Total C captured, % of coal C	0	30%	73%	75%	79%
System life cycle GHG emissions[a]					
kgCO$_2$-eq/GJ$_{DME}$ LHV	349	251	105	98	84
GHGI[b]	1.27	0.94	0.46	0.43	0.38
Costs					
Overnight Installed Capital (million US$_{2007}$$)[c]	1,306	1,198	1,269	1,308	1,317
Levelized DME production cost (US$_{2007}$$/GJ$_{LHV}$)[d]					
Capital, US$/GJ$_{LHV}$	13.85	12.70	13.46	13.87	13.96
O&M, US$/GJ$_{LHV}$	3.45	3.17	3.35	3.46	3.48
Coal, US$/GJ$_{LHV}$	7.49	7.49	7.49	7.49	7.49
CO_2 transport and storage, US$/GJ$_{LHV}$	0	1.56	3.72	3.84	4.05
Electricity sales, US$/GJ$_{LHV}$	−13.61	−13.03	−10.19	−10.14	−9.80
Total (US$_{2007}$$/GJ$_{LHV}$)	**11.18**	**11.89**	**17.83**	**18.52**	**19.18**
Total (US$_{2007}$$/tDME)	317	337	506	526	544
Total (US$_{2007}$$/tLPG-eq)	514	546	820	852	882
Breakeven crude oil price (US$_{2007}$$/bbl)[e]	50	54	85	88	92
Cost of CO_2 captured (US$_{2007}$$/tCO$_2$ avoided)[f]		7.3	27	29	30

a Including emissions associated with coal mining and delivery (1.024 kgC-eq/GJ$_{COAL,LHV}$), emissions at the conversion plant, and emissions from combustion of the DME.

b GHGI, the greenhouse gas emissions index, is the system wide life cycle GHG emissions for production of DME and electricity relative to emissions from a reference system. The reference system consists of LPG from conventional sources, with estimated lifecycle emissions 86 kgCO$_2$/GJ$_{LHV}$, plus electricity from a supercritical pulverized coal power plant with GHG emissions rate of 830.5 kgCO$_2$-eq/MWhe.

c Converted from US$_{2003}$$ in Celik et al. (2004) to US$_{2007}$$ using the Chemical Engineering Plant Cost Index.

d Assuming 7% interest during construction, 15% per year capital charge, 80% capacity factor, annual O&M cost of 4% of overnight capital cost, coal cost of US$2.04/GJ, electricity revenue of US$60/MWh (the 2007 US average generator sale price), and CO_2 transport and storage cost of US$15/tCO$_2$, and zero GHG emissions price.

e A linear regression of monthly wholesale propane price and refiner acquisition cost for crude oil in the United States for the period October 1990 to March 2009 US EIA, 2009b gives the following correlation: Propane price (US$/gallon) = 0.0168 * (US$/bbl$_{oil}$) + 0.133 [R^2 = 0.92]. Assuming the propane density given in Table 12.19, the breakeven oil price in US$/bbl is (US$/t$_{propane}$ − 70.13) / 8.87. We assume this correlation holds equally for LPG.

f This is the difference in US$/GJ$_{LHV}$ levelized cost of DME production with CO_2 capture and the VENT design divided by the difference in system-wide life cycle emissions of CO_2-eq/GJ$_{LHV}$ of DME.

Table 12.21 | Key features of alternative process designs for producing synthetic gasoline and LPG from coal and/or biomass.

Process description[a]	Output capacities		LPG output (10⁶ kg/y)	TPC (millionUS$_{2007}$$)	Biomass fraction (HHV)	Biomass input (10⁶ dt/y)	CO_2 storage rate (10⁶ t/y)	CCS primary energy penalty (%)	GHGI[b]
	Gasoline (bbl/day)	Electricity (MW$_e$)							
CTG-PB-V	32,579	959	125	4,110	0	0	0	–	1.37
CTG-PB-CCS	32,579	760	125	4,310	0	0	10.2	9.8	0.56
CBTG1-PB-CCS	32,579	782	123	4,526	0.1	0.99	10.3	9.5	0.40
CBTG-PB-CCS	11,582	292	42.2	2,086	0.29	1.0	3.7	8.9	0.098
BTG-RC-V	2,315	16.0	8.72	475	1.0	0.5	0	–	0.066
BTG-RC-CCS	2,315	10.2	8.72	482	1.0	0.5	0.513	5.7	– 1.07

a CTG = coal to gasoline+LPG; CBTG = coal+biomass to gasoline+LPG; CBTG1 = coal+biomass to gasoline+LPG with reduced biomass fraction; BTG = biomass to gasoline+LPG;
   PB = partial bypass of syngas around synthesis island for use in power island; RC = recycle of unconverted syngas to maximize liquids production;
   V = venting of CO_2; CCS = carbon capture and storage.
b GHGI, the greenhouse gas emissions index, is the system wide life cycle GHG emissions for production and consumption of the energy products relative to emissions from a
   reference system producing the same amount of liquid fuels and electricity. The reference system consists of electricity from a stand-alone new supercritical pulverized coal power
   plant venting CO_2 plus equivalent crude oil-derived liquid fuels. For details, see Table 12.15, note (c).

For the MTG systems described in Section 12.4.3, a synthetic LPG coproduct is produced, equivalent to about 10% of the synthetic gasoline output (LHV energy basis, see Table 12.15). Systems such as this one might contribute to addressing the challenge of providing universal access to clean cooking fuels, as discussed in the next section.

12.5.3 Co-providing synthetic cooking and transport fuels in the context of a carbon mitigation policy

Increasing conventional LPG use to meet the basic cooking fuel needs of those currently cooking with solid fuels would make a relatively small total energy impact and GHG emission impact. As such, one might argue that meeting the critical energy needs of the energy poor should not be constrained by a requirement that access to energy be provided in a manner consistent with simultaneously mitigating the climate change impacts of the cooking fuel consumed.

In some cases, however, a strong carbon mitigation policy may actually improve the prospects for providing clean energy to satisfy basic cooking needs. This judgment is illustrated here by considering the technology (Table 12.21) and economics (Figure 12.30) of six MTG process designs. Figure 12.30 shows that for five of these systems the economics improve with GHG price. These five systems (four of which involve CCS[15] and four of which involve biomass) all offer substantial reductions in GHG emission rates relative to the crude oil derived products (CODP) and PC-V coal electricity displaced (see final column in Table 12.21). The two pure biomass designs in this table have been
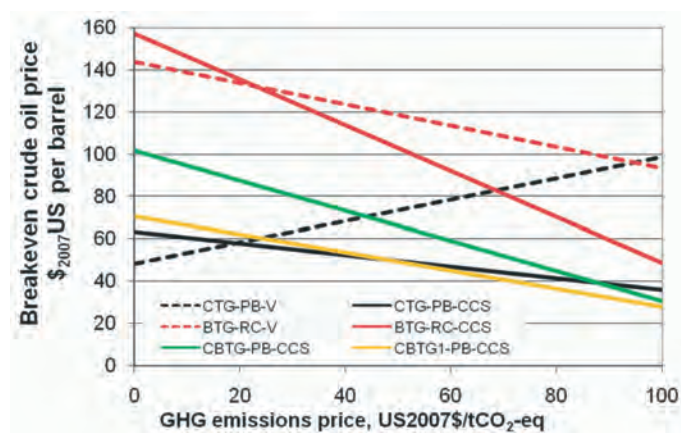

Figure 12.30 | Breakeven crude oil price (BEOP) as a function of the GHG emissions price for the MTG options described in Table 12.21. (See Table 12.6, note (b) and Table 12.16, note (b) for financial parameter and other assumptions. Electricity sales are assumed at the US average grid price plotted in Figure 12.10.)

discussed in Section 12.4.3. The other four designs, which involve the generation of electricity as a major co-product, are described in Section 12.6.

Key observations can be made about the relative economics of the six MTG options:

- CTG-PB-CCS is a coal-only option offering a 44% reduction in system-wide GHG emissions relative to the CODP and PC-V electricity displaced. It offers less costly gasoline than the GHG-emissions-intensive CTG-PB-V for GHG emissions prices greater than US$20/tCO₂-eq.

- CTG-PB-CCS and CBTG1-PB-CCS (an option with biomass accounting for 10% of input energy offering a 60% reduction in system-wide

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15 For all CCS options it is assumed that the captured CO_2 is compressed to 150 bar, transported 100 km, and stored 2 km underground in a deep saline formation via wells for which the maximum injectivity is 2500 tonnes per well per day.

GHG emissions) are both competitive as gasoline providers when crude oil is US$70/bbl at zero GHG emissions price.

- CBTG1-PB-CCS offers less costly gasoline than both CTG-PB-V and CTG-PB-CCS for GHG emissions prices greater than US$50/tCO$_2$-eq.

- CBTG-PB-CCS is an option with biomass accounting for 30% of input energy offering a 90% reduction in system-wide GHG emissions. It could provide gasoline at the least cost of all the options shown at GHG emissions prices greater than about US$100/tCO$_2$-eq.

- BTG-RC-CCS is an option for which biomass accounts for 100% of input energy offering strongly negative GHG emissions. It could provide less costly gasoline than gasoline derived from US$90/bbl of crude oil at GHG emissions prices greater than US$62/tCO$_2$-eq.

- BTG-RC-V can provide less costly gasoline than gasoline derived from US$90/bbl of crude oil at GHG emissions prices greater than US$106/tCO$_2$-eq.

- BTG-RC-CCS can provide less costly gasoline than BTG-RC-V at GHG emissions prices greater than US$23/tCO$_2$-eq.[16]

Analysis in the *World Energy Outlook* 2009 (IEA, 2009b) is helpful in understanding the relative competiveness of alternative technologies in Table 12.21 in a world with high oil prices and policies that constrain GHG emissions. The *Outlook* considers the current situation regarding carbon trading and analyzes prices for crude oil and for GHG emissions for a world on a path toward ultimate stabilization of GHG concentrations in the atmosphere at 450 ppmv. The IEA estimates for its 450 ppmv stabilization scenario that: (i) the world oil price would be stable during 2020–2030 at US$90/bbl (considerably lower than the oil price in this period for the IEA Reference Scenario), (ii) if there were separate emissions trading regimes for OECD+ countries and for other major economies (China, Russia, Brazil, South Africa, Middle East), the GHG emissions price would rise from US$50/t to US$110/t in OECD+ countries between 2020–2030 and would reach US$65/t in other major economies by 2030; and (iii) if there were a single global carbon market for emissions trading, the global GHG emissions price would be US$70/t by 2030.

Thus under such carbon policy constraints, well before 2030, the processes of CTG-PB-CCS and CBTG1-PB-CCS would become cost competitive in both OECD+ and Other Major Economies. Also, CBTG-PB-CCS technologies would be cost-competitive in the post-2030 time frame

in OECD+ countries. Early experience, prior to 2030, with widespread deployment of CTG-PB-CCS and CBTG1-PB-CCS technologies in coal-rich regions such as the United States and China would establish in the market all the technological components needed for subsequent deployment of CBTG-PB-CCS in coal-rich regions and BTG-RC-CCS in coal-poor but biomass-rich regions. The economic prospects for BTG-RC-V are not auspicious, although the BTG-RC-CCS option is prospectively economically viable in coal-poor but biomass-rich regions in the period after 2030 where there is adequate CO$_2$ storage capacity and emissions trading opportunities. For example, when the crude oil price is US$90/bbl, when coal coprocessing is not a realistic option, and the emissions trading price is US$70/t the BTG-RC-CCS option would be highly competitive.

12.5.3.1   Two Thought Experiments

Two thought experiments are presented here, one for China (a coal-rich region) and one for Africa (a biomass-rich but coal-poor region). In this experiment, both regions are under a carbon policy constraint. The discussion focuses on the strategic linkages between providing fuels/electricity for transportation on the one hand, versus providing LPG to satisfy basic human needs for cooking on the other hand.

China
Why China? China is a good candidate for early deployment of CTG-PB-CCS and CBTG1-PB-CCS technologies to make simultaneously liquid fuels for transportation and LPG for cooking. There are many reasons:

- China is a coal-rich country, accounting for more than 70% of coal use by developing countries in 2007 (IEA, 2009b).

- China has a strong coal gasification-based chemical process industry (making gasoline is very much like making chemicals via coal gasification).

- China already has experience with CTG technology. A demonstration plant producing 2600 barrels of gasoline per day came online in 2009, built by Uhde for the Shanxi Jincheng Anthracite Coal Mining Co. Ltd. This plant uses the ExxonMobil methanol-to-gasoline process and is coupled to a fluidized bed hard coal gasifier and a plant for making methanol from coal via gasification.

- Potential demand for clean cooking fuels in China is huge. Hundreds of millions of Chinese still cook with solid fuels.

- As a large food producer, China has substantial crop residue resources that could be used for energy purposes.[17]

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16 This breakeven GHG emissions price for shifting from the V to the CCS variant of the BTG-RC option is higher than the US$20/tCO$_2$-eq indicated for this pair of options in Figure 12.24 because in the present case the assumed biomass input rate is half as large.

17 Prospective crop residue supplies in China have been estimated by Li et al. (1998), who estimate that crop residue supplies potentially available for energy applications in China in 2010 were 376 million dry t/yr.

- China is a good candidate for pursuing synthetic transportation fuels derived from secure domestic coal and biomass supplies because its domestic oil supplies are scarce and its demand for liquid fuels for transportation is rapidly growing.

- The coproduction approach to CCS, which offers low energy and water penalties and low capture costs, may be perceived as an attractive approach for reducing coal-related GHG emissions in China.

The thought experiment: To illustrate the possibilities for early action for coal-based technologies, suppose that in China in the period prior to 2030 enough MTG plants are built to provide LPG sufficient to meet the needs of the 1.06 billion people that were cooking with solid fuels as of 2001.[18]

Assumptions: It is assumed that during this period the carbon policy in China becomes sufficiently stringent to warrant deployment of both CTG-PB-CCS and CBTG1-PB-CCS systems. Furthermore, it is assumed that a mix of these two technologies is deployed such that on average gasoline, LPG, and electricity are provided at one half the GHG emission rate of the CODP and PC-V electricity displaced. This implies that 62% of the capacity would be CTG-PB-CCS plants and 38% would be CBTG1-PB-CCS plants (so that, on average, biomass accounts for 3.8% of primary energy input).

Findings: The system-wide features of this combination of plants would yield 100% satisfaction of the need for clean cooking fuels and a 50% reduction in GHG emissions relative to the energy products displaced. In addition, the features would be the following:

- the required investment (Total Plant Cost (TPC)) would be US$1.1 trillion (US$_{2007}$);

- synthetic gasoline would be produced at a rate of 13.5 EJ/yr (322 Mtoe/yr or 66% of projected transportation energy demand in China in 2030 (IEA, 2009b);

- electricity would be produced at a rate of 1516 million MWh/yr (67% of projected increase in coal electricity generation in China, 2015–2030 (IEA, 2009b);

- the biomass required is 95 Mt/yr dry biomass or 25% of prospective crop residue supplies available for energy in China;[17]

- CO_2 would be stored in deep geological formations at a rate of 2.57 Gt/yr.

This coproduction approach also would offer significant advantages relative to provision of the same energy products via use of CTG-RC-CCS (a coal-only design that maximizes gasoline output) plants plus CIGCC-CCS plants to provide the electricity needed in excess of what can be provided by the CTG-RC-CCS plants. Relative to the case with production in separate facilities, the coproduction with coal/biomass coprocessing approach would involve comparable total investment, total primary input, and CO_2 storage requirements, but would generate 15% less GHG emissions. Moreover, when evaluating the coproduction system as an electricity generator, the levelized cost of electricity at crude oil and GHG emissions prices of US$90/bbl and US$65/tCO_2-eq, respectively, would be only 14% as large as for a 2028 MW$_e$ CIGCC-CCS plant having the same primary energy input as the average coproduction unit that provides 768 MW$_e$ of electricity. The reasons for the outstanding economic performance of coproduction plants evaluated as electricity generators compared to stand-alone power plants are discussed in Section 12.6.3.

Africa

Why Africa? The region of Africa is a good candidate for deployment of BTG-RC-CCS technology in the 2030+ time frame. There are many reasons:

- Much of Africa is biomass-rich but coal-poor (except for Botswana and South Africa).

- Much of Africa is economically poor and in need of industrial development such as that which BTG-RC-CCS technology could help provide.

- Africa has a huge population in need of clean cooking fuels, with some 710 million people (Hutton et al., 2006) dependent on solid fuels for cooking.[19]

- Much of Africa must spend precious export earnings on fuels for transportation as well as on LPG for cooking and thus stands to benefit economically from having a domestic BTG-RC-CCS synfuels industry.

- Preliminary indications are that there might be significant CO_2 storage opportunities in Africa (see Chapter 13).

- Although at low GHG emissions prices it would make more economic sense for biomass-rich/coal-poor countries to import coal and make gasoline by coprocessing coal and biomass, biomass to gasoline plants would become more cost competitive at high GHG emissions prices.[20] So, if there were a reasonable expectation of such high GHG emissions prices in the future, perhaps before 2050, such

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18 Following the findings of Hutton et al., (2006) it is assumed that the average per capita LPG requirement for China is 29.3 kg/yr (43 Watts).

19 In 2006 biomass used for cooking in the developing world (assumed to be total biomass use for energy, minus biomass used for power generation, minus industrial use of biomass, and minus biomass used to make transport fuels) was 229 Mtoe (9.6 EJ) in Africa, 224 Mtoe (9.4 EJ) in China, 131 Mtoe (5.5 EJ) in India, 142 Mtoe (6.0 EJ) in other non-OECD Asia, and 32 Mtoe (1.3 EJ) in Latin America (IEA, 2008b). Thus Africa accounted for about 30% of global biomass use for cooking in 2006.

20 If the competition were between CBTG-PB-CCS and BTG-RC-CCS plants each consuming 0.5 million dry tonnes of biomass annually, the BTG-RC-CCS option would provide gasoline at a lower levelized cost of fuel when the GHG emissions price is greater than US$108/t$CO_2$-eq.

countries might be reluctant to make such coal-related infrastructure investments.

The thought experiment: A thought experiment is presented that envisions widespread deployment of BTG-RC-CCS technology in Africa in the 2030+ time frame.

Assumptions: The following conditions are assumed:

- Before 2030 all the needed technological components are established in the market somewhere in the world via earlier widespread deployment of CTG-PB-CCS and CBTG1-PB-CCS technologies (e.g., as described in the previous China thought experiment).

- The GHG emissions price is high enough (greater than US$62/tCO$_2$-eq) that BTG-RC-CCS is able to sell gasoline that is competitive with gasoline derived from US$90/bbl of crude oil (see Figure 12.30).

- There are concerted multilateral activities prior to 2030 aimed at: (i) identifying geological CO$_2$ storage opportunities in Africa's biomass-rich regions; (ii) identifying prospective biomass supplies that can be provided on a sustainable basis (avoiding supplies that involve deforestation, destruction of soil carbon stores, and competition with food production); (iii) building in currently economically poor, biomass-rich regions the physical infrastructures and human capacity needed to support rapid development of a BTG-RC-CCS industry.

- BTG-RC-CCS plants are deployed at modest scales to keep biomass supply logistics and CO$_2$ infrastructure challenges from being too daunting—producing gasoline at a scale ~2300 bbl/day, processing only 0.5 Mt/yr of dry biomass, and storing underground only 0.5 Mt/yr of CO$_2$, see Table 12.21. To get a sense of the scale of the activities, consider that Campbell et al. (2008) have estimated for tropical regions that yields for growing mixed prairie grasses on abandoned cropland in tropical regions are 7–20 dry t/yr-hectare. For these yields the amount of land required to serve a single bio-fuels plant is 250–714 km^2. The average biomass transport distance is 30–50 km if the biomass is available on 20% of the land around the plant and 40–70 km if the biomass is available on only 10% of the land.

- For the thought experiment it is assumed that the amount of biomass available for prospective BTG-RC-CCS plants is the same as the actual estimated amount of biomass that was used for cooking in 2006 (229 Mtoe/yr = 9.59 EJ/yr).[19] If this much biomass were grown as an energy crop at a yield of 7–20 dry t/hectare-yr, some 27–78 million hectares would be required for all of Africa. To put this into perspective, Cai et al. (2009) estimates that worldwide the amount of land available for growing biomass for energy on both abandoned and/or degraded cropland and grassland, savanna, and shrubland with marginal productivity suitable for use with low-input

high diversity prairie grasses as energy crops is 1343 million ha of which one third to one half (450–670 million hectares) is in Africa.[21]

Making cooking with LPG affordable: The analysis below explores prospects for earning income that current users of biomass for cooking might pursue. They could sell their biomass to "biomass-supply-logistics" agents, who would in turn make the biomass available to operators of BTG-RC-CCS plants. And they could generate thereby enough revenue to cover both purchases of LPG for cooking and the annualized cost of purchasing an LPG stove and storage canisters.

Compare the energy requirements for cooking with these fuels. The current rate of use of biomass for cooking by 710 million people in Africa (229 Mtoe/yr, 9.6 EJ/yr),[19] corresponds to a wood consumption rate of 0.7 dry tonnes per capita/yr = 428 Watts/capita. According to Hutton et al. (2006) the average per capita consumption rate of LPG for cooking in Africa as a substitute for wood would be 14.4 kg/yr or 21 Watts. Both of these cooking rates are consistent with historical rates for cooking with wood and fluid fuels (Figure 12.28).

Energy requirements for cooking via LPG are only ~5% of the energy requirements for cooking via the direct burning of biomass. This makes LPG prospectively affordable even for very poor households. The following illustrative calculation suggests how LPG might be made affordable: Suppose that the crude oil and GHG emissions prices are US$90/bbl and US$70/tCO$_2$-eq, respectively, so that synthetic gasoline produced with carbon capture and storage would be cost-competitive with gasoline from crude oil (Figure 12.30). At these crude oil and GHG emissions prices, the estimated average retail LPG price would be US$1.39/kg in rural Africa.[22] Thus the total average cost of LPG for a family of 4.4 (the average household size in Africa) would be:

$$4.4 \times \left(\frac{US\$1.38}{kg} \right) \times \frac{14.3 \frac{kg}{capita}}{yr} = \frac{US\$87}{yr} \qquad (3)$$

The total cost of cooking also includes capital expenses for the stove and storage canisters, which are estimated to be about US$50 (IEA, 2006) or an annualized cost of US$8/yr,[23], [24] so that the total annualized

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21 Of the global total Cai et al. (2009) estimate that 256–463 million hectares is abandoned and/or degraded cropland. For comparison, Campbell et al. (2008) estimate that globally the amount of land available on abandoned cropland is 385–472 million hectares.

22 Based on a wholesale LPG price of $1.07/kg for $90/bbl + a $0.31/kg markup to retail for rural Africa, as estimated in Hutton et al. (2006).

23 Assuming a 10% discount rate and a 10-year system life, the capital recovery factor is 16.3%/yr for the capital equipment.

24 Some sort of microfinancing program may be needed to overcome the expenditure "lumpiness" hurdle of the stove/canisters investment, but otherwise the required investment would not appear to be a show-stopper for poor households.

cost is US$95/yr per average African household. The price P_W (in US$/t) at which a family would have to sell biomass currently used for cooking to a biomass-supply-logistics agent of a synfuel producer in order to be able to afford the LPG without an additional income stream is given by:

$$4.4 \times \left(0.70 \frac{\text{tonnes} \frac{\text{wood}}{\text{capita}}}{\text{yr}} \right) \times P_W = \frac{\text{US\$95}}{\text{yr}} \Rightarrow P_W = \text{US\$31 per tonne} \quad (4)$$

This is a plausible selling price because it is only 30% of the assumed price of wood delivered to the conversion facility[25] – allowing a margin of revenue to the biomass-supply-logistics agent that is plausibly enough to pay for profitably getting the biomass purchased from cooking fuel consumers to the synfuel producer. (Detailed biomass supply logistics analysis is needed to ascertain the validity of this very preliminary judgment.)

Implications of the thought experiment for Africa: The biomass now used for cooking in Africa could support the operation of 1023 BTG-RC-CCS plants like those described in Table 12.21. If such a shift in biomass use were made, there would be Africa-wide implications:

- a total investment requirement for BTG-RC-CCS plants of US$528 billion;

- enough LPG to meet the cooking fuel needs of 94%[26] of the population currently cooking with biomass;

- 2.28 million bbl/day average gasoline output, equivalent to 90% of Africa's transportation fuel demand for 2030 as projected by the IEA (IEA, 2010) or 11% of world gasoline output of refineries in 2007, some 21.3 million bbl/day (47 EJ/yr) (US EIA, 2009b);

- 88 million MWh/yr of electricity, equivalent to 7% of Africa's electricity generation in 2030 as projected by the IEA; and

- annual storage in geological formations of 562 $MtCO_2$/yr.

Toward a business plan for BTG-RC-CCS technology deployment in Africa: This thought experiment suggests that widespread deployment of BTG-RC-CCS technology in Africa might not only go a long way

towards meeting Africa's transportation fuel needs but also might help to catalyze widespread use of LPG for cooking, even among very poor households.

But much new thinking is needed about business strategies and public policies required to convert this thought experiment into a plausible energy projection for Africa. A list of proposed public policies for both the China thought experiment and the Africa thought experiment is presented in Section 12.5.3.2.

Although articulating appropriate business plans is beyond the scope of the current analysis, we conclude the economic analysis with a suggestion for one possible element of such business plans: involvement of industrial firms that produce and/or use crude oil-derived transportation fuel as investors in BTG-RC-CCS systems.

The reason for this suggestion is that such firms may be interested in procuring credits for the strong negative GHG emissions characterizing BTG-RC-CCS systems to offset emissions from the crude oil-derived products they produce or consume. The production of each barrel of gasoline by a BTG-RC-CCS plant provides enough negative GHG emissions to offset the emissions of 1.37 barrels of crude oil-derived gasoline.[27] Assuming that crude oil and GHG emissions prices are US$90/bbl and US$70/t, respectively, the annual cost of purchasing credits from a single BTG-RC-CCS plant would be US$34 million. The present worth of purchasing such credits over the life of the plant would be US$357 million,[28] which is about three fourth of the investment cost (TPC) for a BTG-RC-CCS plant (Table 12.21).

The industrial firms that are producers and/or users of crude oil-derived transportation fuel could either try to buy emissions credits from BTG-RC-CCS plant owners in an emissions trading market or they could instead invest in BTG-RC-CCS plants. In the former case, they would risk not being able get the full amount of credits they are seeking to obtain, while in the latter case they would have guaranteed access to these credits.

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25 For all the systems presented in Figure 12.30 and involving biomass it is assumed that the delivered price of biomass at the conversion plant is $5.0GJ (HHV), which corresponds to a wood price of $103/dry tonne.

26 The cooking fuel production could be increased to 100% of the current cooking fuel needs by reducing the gasoline output of the BTG-RC-CCS plants in favor of producing some DME as a coproduct and blending this with LPG for use as a cooking fuel. So doing would be straightforward because the first step in the production of gasoline from methanol (CH_3OH) is methanol dehydration, which produces DME (CH_3OCH_3) and water. See additional discussion of DME in Section 12.5.1.

27 Alternatively, offsets might be sought from plants that make electricity via gasification of biomass with CCS, in which case a much larger fraction of the C in the biomass can be stored underground. If the negative emissions from power plants are used to offset emissions from crude oil-derived gasoline, a comparable amount of "effective" zero GHG emitting liquid fuels would be provided via the biomass to power with CO_2 capture and storage route as via the BTG-RC-CCS route (1.04 and 0.94 GJ of zero net GHG-emitting gasoline is provided per GJ of dry biomass input in the BTG-RC-CCS and power-only cases, respectively). In the power-only case, the gasoline provided is 100% crude oil-derived gasoline offsets; in the BTG-RC-CCS case, 42% of the gasoline is actually produced and 58% is in the form of crude oil-derived offsets. Thus if a biomass-rich country seeks to reduce oil imports as well as mitigate climate change, it is likely to choose the synfuel option over the power option. Another consideration that might tip the balance in favor of the synfuel option is that CO_2 storage capacity is a non-renewable resource, and the power option stores 1.6 times as much CO_2 per tonne of biomass as the synfuel option.

28 Assuming a 7% discount rate and a 20-year economic life of a BTG-RC-CCS plant.

12.5.3.2   Public Policy Issues

Despite the huge public benefits and seemingly attractive economics indicated by the China and Africa thought experiments, converting these thought experiments into projects will require new public policy initiatives. There would be many hurdles to overcome, including issues related to the viability of CO_2 storage at gigascale, CO_2 storage potential, sustainable biomass production potential, commercialization of large biomass gasifiers, new industrial collaborations, the rural lighting challenge, and physical infrastructure and human capacity for a BTG-RC-CCS industry. These public policy issues are outlined here.

Viability of CO_2 storage at gigascale: There is widespread belief in the scientific community that CCS is a viable carbon mitigation option at scales storing billions of tonnes of CO_2 annually worldwide (IPCC, 2005 and Chapter 13). Demonstration projects are needed, however, to prove and gain a high degree of confidence in CCS viability and also to provide a solid scientific and engineering basis for widespread deployment of CCS technologies post-2020. Commercial-scale integrated CCS demonstration projects worldwide are needed during the coming decade, with emphasis on CO_2 storage in deep saline formations, which account for most of the geological storage opportunity. Such projects are needed for several reasons. They could address scientific questions that can only be answered in projects that inject and store CO_2 at rates comparable to those for commercial projects. They could demonstrate to the satisfaction of a wide range of stakeholder groups that CCS is a viable major option to be included in the portfolio of carbon mitigation options. And they could provide the experience base needed for formulating practicable regulations governing CO_2 storage.

An international political framework for early CCS action has already been established. In July 2008, an agreement was reached by the G8 countries at the G8 Summit in Japan that 20 large-scale fully integrated CCS demonstration projects worldwide would be deployed by the middle of the next decade, with the aim of establishing the basis for broad commercial deployment of CCS technologies after 2020. In July 2009, the leaders of the G8 countries re-iterated their call for the projects, and in February 2010 US President Obama issued a Presidential Memorandum calling for five to ten commercial scale CCS demonstration projects to be up and running in the United States by 2016.

Much if not all of the incremental cost of CCS for the 20 projects called for by the G8 will probably have to be paid for by governments (individually or collectively) because of the likelihood that carbon prices will be lower initially than what will be needed to make pursuit of CCS a profitable activity for private companies.

If governments will have to pay for the incremental CCS cost, they will want to pursue projects in which they can maximize the learning about the gigascale prospects of CCS per dollar spent.

An important consideration is that coproduction systems based on coal or coal + biomass generate, as a natural part of the process of their manufacture, relatively pure streams of CO_2 for which the incremental cost of CO_2 capture is low. Accordingly, coproduction facilities (such as the CTG-PB-CCS and CBTG1-PB-CCS described in Table 12.21) built in coal-rich countries should be considered seriously as candidates for some of the needed CCS early action projects and supported financially jointly by the governments of several coal-intensive energy economies.

CO_2 storage potential: CO_2 storage prospects are not well known in countries where clean cooking fuels are sorely needed and where attractive economics for providing these fuels to poor households can plausibly be realized in conjunction with the building of synfuel plants with CCS. "Bottom-up" assessments of storage prospects, including the construction of supply curves (storage capacity in tonnes vs cost in US$/t), are needed on a reservoir-by-reservoir basis. These assessments should be carried out in each of the major regions requiring clean cooking fuels – with financial support from the international community.

Sustainable biomass production potential: Assessments should be carried out in biomass-rich regions to determine the prospects for biomass production for energy. Such production should be on a sustainable basis in which conflicts with food production, adverse indirect land-use impacts, and biodiversity conflicts are minimized. Emphasis should be on agricultural residues, forest residues (including mill residues, logging residues, diseased tree removals, fuel treatment thinnings, and productivity enhancement thinnings), and the growing of dedicated energy crops on abandoned croplands and other degraded lands. The growing of bioenergy crops on marginal lands should be done in ways that enhance the wellbeing of poor indigenous populations currently use such lands for their livelihoods. One way of expanding biomass production on marginal lands without forcing off the land local populations would be to encourage the local populations to grow biomass for energy by creating corporate smallholder partnerships that establish agreements for industries to purchase biomass from smallholders. Outgrower schemes such as these have been common for some time in agriculture; smallholders are now playing an increasingly important role in the establishment and management of planted forests (Cushion et al., 2010).

These assessments should be carried out in each of the major regions requiring clean cooking fuels – with financial support from the international community.

Commercialization of large biomass gasifiers: Successful demonstration projects have been carried out for biomass gasifiers at small scales (processing tens of MW of biomass). But there are no commercial biomass gasifiers capable of processing 300–600 MW of biomass – the scales for the conversion systems described here. Policies are needed to encourage commercialization of biomass gasifiers suitable for coupling to synthetic fuel production units at these scales. Such commercialization efforts should be carried out in parallel with early deployment of CBTG1-PB-CCS

systems (designed for ~10% biomass or less) that could involve instead co-gasification of biomass and coal in suitable coal gasifiers.

New industrial collaborations: New public policies are needed to facilitate industrial collaborations between companies producing transportation fuels, electricity, and clean cooking fuels and to encourage coprocessing of coal and biomass in regions having significant supplies of both (e.g., United States and China). It would be desirable to identify policy instruments that specify performance rather than technology and maximize use of market forces in meeting performance goals. Promising approaches along these lines include mandating a Low Carbon Fuel Standard (as in California); a low carbon standard for coal electricity, perhaps modeled after Renewable Portfolio Standards or green certificate markets; and a Universal Clean Cooking Fuel Standard in regions requiring major infusions of clean cooking fuels, perhaps modeled after the "obligation to serve" mandates of the rural electrification programs introduced in the United States in the 1930s. The latter could plausibly facilitate the formation of strategic industrial alliances that would be capable of guaranteeing universal access to clean cooking fuels without major subsidy.

Rural lighting challenge: Policies aimed at inducing a shift from biomass to clean cooking fuels should be complemented by policies to promote universal access to modern lighting technologies (see also Chapter 23).

Physical infrastructure and human capacity for a BTG-RC-CCS industry: Official development assistance (ODA) should be expanded for economically poor but biomass-rich and coal-poor regions. The increment should be directed to developing the physical infrastructures and human capacities needed to build and manage large BTG-RC-CCS industries. This additional ODA should aim for established infrastructures and capacities *before* GHG emission prices are high enough to launch BTG-RC-CCS technologies in the market.

12.6 Coproduction of Liquid Fuels and Electricity from Non-petroleum Feedstocks

Coproduction can enhance cost-competitiveness. The discussion of gasification-based synfuels in Section 12.4.3 was focused on recycle (RC) systems designed to maximize liquid fuel output. In RC systems, syngas unconverted in a single pass through the synthesis reactor is recycled to the reactor to maximize synfuel yield. A major study of alternative system configurations for making FTL from coal, from biomass, and from coal + biomass (Liu et al., 2011a) found that FTL can often be produced more cost-effectively in so-called "once-through" (OT) systems, in which syngas unconverted in a single pass is burned to make coproduct electricity in a gas turbine/steam turbine combined cycle power plant (See also Larson et al., 2010). OT configurations are worthwhile exploring from a synfuels production perspective for the slurry-phase synthesis reactors investigated by Liu et al. (2011a) because these reactors can yield high

one-pass conversion of $CO+H_2$ to liquids – much higher than is feasible with gas-phase reactors. A major study of alternative system configurations for making gasoline via the methanol-to-gasoline process from coal, from biomass, and from coal + biomass (Liu et al., forthcoming) also found that gasoline can often be produced more cost-effectively via systems that produce electricity as a major coproduct.

Here the merits of coproduction for both FTL and MTG systems are discussed for the six systems described in Table 12.22 that involve coal (both –V and –CCS configurations) and coal + biomass (only –CCS configurations). Since detailed descriptions of RC variants of FTL and MTG systems were already made in Section 12.4.3, here only the major differences introduced by the coproduction designs are discussed.

Figure 12.31 shows several OT configurations for coal and coal/biomass FTL systems. When iron-based synthesis catalysts are used (as in the analysis in Liu et al., 2011a), CO_2 removal from synthesis gas in –CCS configurations is required downstream as well as upstream of synthesis because of the water-gas-shift activity of iron-based catalysts, and downstream CO_2 removal accounts for more than half of the total CO_2 removed. Also, a gas turbine/steam turbine combined cycle rather than a steam turbine is used to generate electricity on the power island.

The MTG designs that coproduce electricity and gasoline use a bypass of some of the syngas around the methanol synthesis reactor to directly feed a gas turbine/steam turbine combined cycle power plant in so-called partial bypass (PB) configurations (Figure 12.32).[29] An additional water gas shift reactor is introduced to convert the bypass syngas to mainly CO_2 and H_2, from which the CO_2 is captured for storage, and H_2 is the main constituent of the fuel gas delivered to the combined cycle power plant.

12.6.1 Performance Estimates

Greenhouse gas emissions are the focus of the discussion of performance estimates here. To facilitate comparisons, the coal-only plants (Figure 12.31, Table 12.22) have the same levels of coal inputs as the corresponding RC plants described in Table 12.15 that provided 50,000 bbl/day of crude oil products displaced for both FTL and MTG. As shown in Table 12.22, the OT and PB system configurations produce less liquid fuel and much more electricity from this coal than the corresponding RC systems. As in the RC cases, an important metric for comparing emissions for different system configurations is the GHGI: the ratio of the fuel cycle wide emissions of greenhouse gases from these systems are compared to emissions from a reference system.

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29 A partial-bypass, rather than a "once through" (OT), process design is utilized for the MTG systems here because the assumed methanol synthesis reactor is a gas-phase design, for which the per-pass conversion of syngas is small, making it ill-suited for use in an OT process configuration. A liquid-phase methanol synthesis reactor would have much higher single-pass conversion and as a result might be better-suited for an OT application.

Table 12.22 | Performance estimates for converting coal and coal + biomass to electricity + FTL or MTG.

Process configuration >>>	CTL-OT-V	CTL-OT-CCS	CTG-PB-V	CTG-PB-CCS	CBTL-OT-CCS	CBTG-PB-CCS
Coal input, as received metric t/day	24,087	24,087	20,869	20,869	3220	5260
Coal input, MW HHV	7559	7559	6549	6549	1011	1651
Biomass input, as received metric t/day	0	0	0	0	3,581	3,581
Biomass input, MW HHV	0	0	0	0	661	661
Production of all liquids, MW LHV	2256	2256	2100	2100	508	743
Production of LPG, MW LHV	-	-	202	202	-	68
Production, bbl/day COPD[a], excl. LPG	35,706	35,706	32,579	32,579	8,036	11,582
Gross electricity production, MW	1661	1653	1417	1369	384	521
On-site electricity consumption, MW	401	595	459	609	127	229
Net electricity exports to grid, MW	1260	1058	959	760	257	292
Energy ratios						
Liquids out/energy in (HHVs)	32.1%	32.1%	34.4%	34.4%	32.5%	34.5%
Net electricity/energy in (HHV)	16.7%	14.0%	14.6%	11.6%	15.4%	12.6%
(Liquids+electricity)/energy in (HHVs)	48.8%	46.1%	49.1%	46.0%	48.1%	47.2%
Carbon accounting						
C input as feedstock, kgC/second	178	178	154	154	40	55
C stored as CO_2, % of feedstock C	0.0%	52.2%	0.0%	63.7%	54.0%	64.9%
C in char (unburned), % of feedstock C	4.0%	4.0%	4.0%	4.0%	3.6%	3.7%
C vented to atm., % of feedstock C	71.6%	19.5%	70.5%	6.8%	18.2%	6.3%
C in liquid fuels, % of feedstock C	24.4%	24.4%	25.5%	25.5%	24.2%	25.1%
C stored, 10^6 tCO_2/yr (at 90% cap factor)	0	9.6	0	10.2	2.3	3.7
Full fuel cycle GHG emissions (incl. from feedstock supply and conversion, fuels distribution and use)						
$kgCO_2$-eq/GJ liquid fuel LHV	289.6	139.1	298.3	108.9	19.4	19.7
tCO_2-eq/hr	2352	1129	2038	744	35	48
Reference system emissions, tCO_2-eq/hr	1790	1623	1483	1318	381	538
GHG emissions index – GHGI[b]	1.31	0.70	1.37	0.56	0.093	0.089

a COPD = crude oil products displaced.
b GHGI, the greenhouse gas emissions index, is the system wide life cycle GHG emissions for production and consumption of the energy products relative to emissions from a reference system producing the same amount of liquid fuels and electricity. For details, see Table 12.15, note (c).
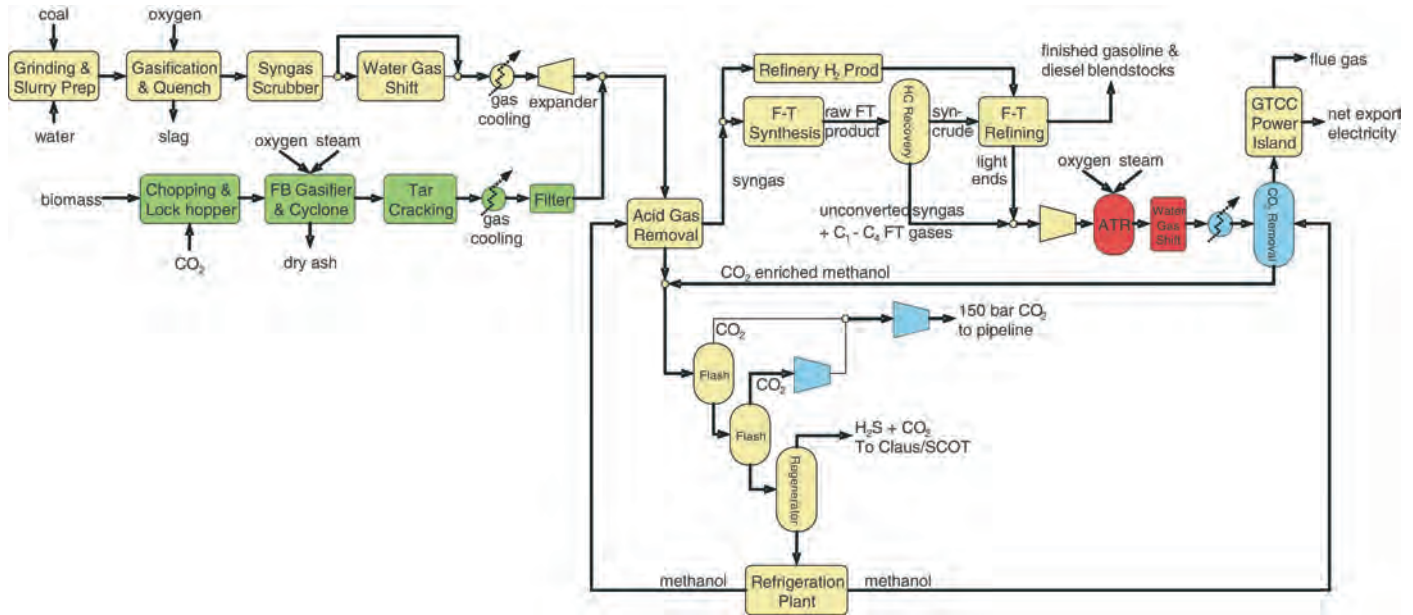
Figure 12.31 | CTL-OT-V system (including only yellow-shaded components) that provides F-T liquids + electricity from coal via gasification while venting the captured CO_2 coproduct. Upstream of the synthesis reactor CO_2 accounting for 25% of the C in the coal is captured along with H_2S using Rectisol. The H_2S is converted to elemental sulfur in a Claus plant and the CO_2 is vented.

With the addition of the blue-shaded components, the system (CTL-OT-CCS) includes capture of CO_2 both upstream of the synthesis reactor (accounting for 25% of C in the coal) and downstream of it (accounting for 27% of C in the coal). The CO_2 is compressed to 150 bar and delivered to a pipeline for transport to a geological storage site.

With the further addition of the green-shaded components, the system (CBTL-OT-CCS) co-processes biomass with coal.

And finally, the further addition of the red components creates a design (CBTL-OTA-CCS) that includes autothermal reforming (ATR) of the C_1-C_4 components in the fuel stream to the power island, followed by water gas shifting. The autothermal reforming (ATR) plus WGS creates more CO_2 for capture downstream of synthesis than is the case with the CBTL-OT-CCS system.

Both the CBTL-OT-CCS and CBTL-OTA-CCS systems have been designed with enough biomass to realize GHGI < 0.10. CBTL-OT-CCS, storing as CO_2 54% of the feedstock C, requires coprocessing 40% biomass, whereas CBTL-OTA-CCS, storing as CO_2 65% of the feedstock C, requires coprocessing only 29% biomass to realize essentially the same GHGI value.
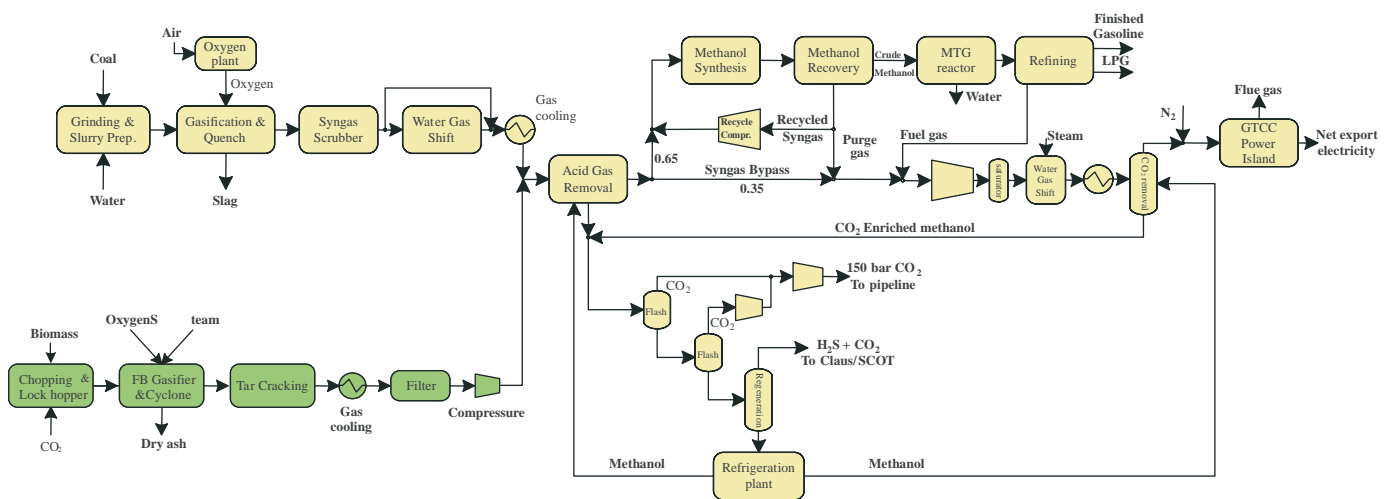
Figure 12.32 | CTG-PB-CCS system (yellow-shaded components) that provides gasoline and LPG + electricity from coal. H_2S is converted to elemental sulfur, and CO_2 is captured both upstream and downstream of synthesis (accounting for 64% of C in the coal), compressed to 150 bar, and delivered to a pipeline for transport to a geological storage site. With the addition of the green-shaded components, the system (CBTG-PB-CCS) produces gasoline and LPG + electricity from coal and biomass. CO_2 accounting for 65% of C in the feedstocks is captured and sent to geological storage.
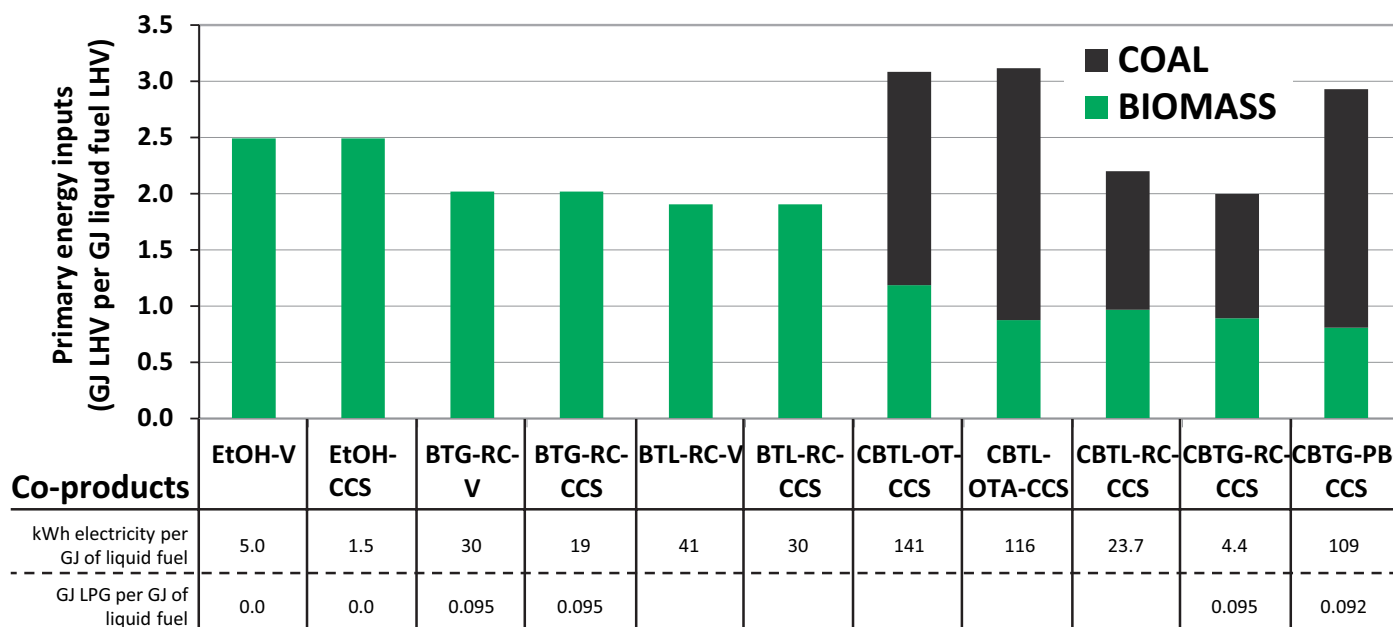
Figure 12.33 | Biomass (and coal) required to produce alternative fuels having low/zero fuel-cycle-wide GHG emissions. For this graph, all primary energy input is allocated to liquid fuels even though all systems also provide electricity. For details on the cellulosic ethanol options (EtOH-V and EtOH-CCS) see Box 12.3. Source: based on Liu et al., 2011a.

For the coal-only designs, the GHGI is 1.3–1.4 for the systems with venting of CO_2, indicating that emissions would be considerably higher than for the reference system. Adding carbon capture and storage reduces emissions relative to the reference system by 30–40% (GHGI = 0.56–0.70).

The two coal + biomass systems described in Table 12.22 are each designed for a total biomass consumption of 1 Mt/yr dry biomass, together with an amount of coal that results in a GHGI of 0.1 or less, i.e., 10% of the emissions of the reference system or less. For the FTL systems, 40% of the input feedstock energy is biomass. It is 29% for the MTG system. Unlike systems that produce liquid fuels using only biomass as a feedstock, the energy content in the near-zero GHG liquid fuels produced from coal/biomass systems is comparable to or greater than the energy contained in the input biomass (see Figure 12.33). The reason is that a large percentage of the energy input for these coal/biomass coprocessing options is provided by coal, as shown in Figure 12.33.

12.6.2   Cost estimates

When coproduction systems are evaluated from a fuels perspective, the LCOF is given by:

$$LCOF = \frac{\text{levelized system cost}\, \frac{US\$}{yr} - \text{levelized value of electricity coproduct}\, \frac{US\$}{yr}}{\text{levelized fuel production rate}\, \frac{GJ}{yr}} \quad (5)$$
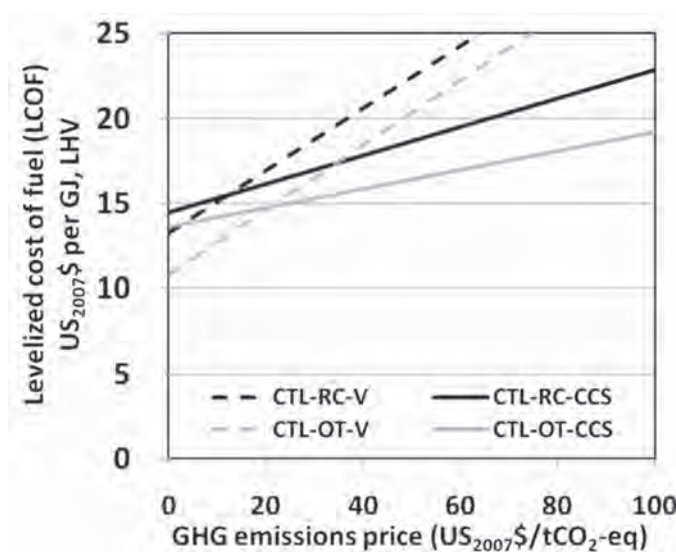
Figure 12.34 | Comparison of CTL production costs ($US_{2007}\$$): OT vs RC options, both with CO_2 vented (–V) and with carbon capture and storage (–CCS). (See Table 12.6, note (b) for financial parameter assumptions. Also, electricity sales are assumed at the US average grid price plotted in Figure 12.10.) Source: based on Liu et al., 2011a.

In Liu et al. (2011a) and in Liu et al. (forthcoming) it is assumed that the electricity coproduct is valued at the US average grid generation price in 2007 (US$60/MWh) augmented by the value of the average grid GHG emission rate in that year (see Figure 12.10).

Figures 12.34 and 12.35 present LCOFs vs GHG emissions price for the coal only – OT and –PB systems, respectively, as well as the corresponding LCOFs for the RC alternatives.
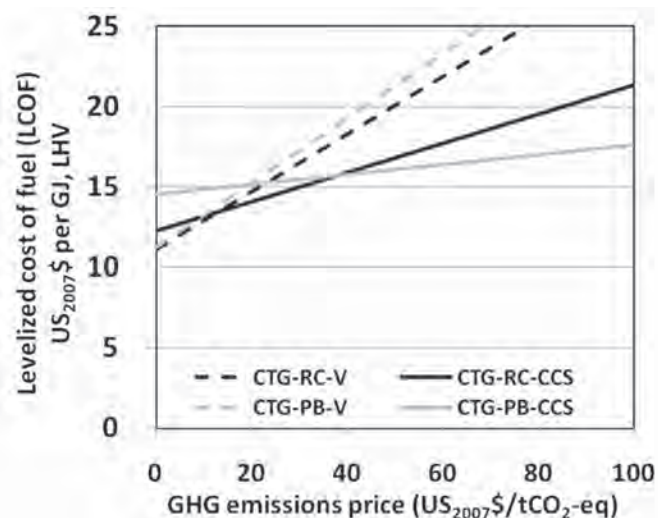
Figure 12.35 | Comparison of CTG production costs (US$_{2007}$): PB vs RC options, both with CO_2 vented (–V) and with carbon capture and storage (–CCS). Same financial parameter and electricity price assumptions as Figure 12.34. Source: based on Liu et al., forthcoming.

Figure 12.36 | Liquid fuel production costs (US$_{2007}$) for alternative FTL-OT and MTG-PB options, involving coal and coal + biomass as feedstocks. Same financial parameter and electricity price assumptions as Figure 12.34. Source: based on Liu et al., 2011a.

Figure 12.34 shows that the LCOF is 18% less for the CTL-OT-V case than for the CTL-RC-V case when the GHG emissions price is zero. This economic advantage of the OT option can be attributed in large part to the high marginal efficiency of power generation (Liu et al., 2011a): for OT and RC plants having the same FTL outputs, the difference in electricity outputs divided by the extra coal required for the OT case is 45% for the –V case and 39% for the –CCS case (HHV basis). In both instances these marginal efficiencies for power generation for OT options are much higher than for stand-alone power plants, e.g., 37.5% and 31.0% for CIGCC in –V and –CCS configurations, respectively (Table 12.7, PEI cases). For CTG systems, there are also gains in marginal efficiency, but the gains are not as pronounced as for CTL systems: the marginal efficiencies of incremental power generation are 38% for the –V case and 32% for the –CCS case.

For CTG systems (Figure 12.35) the PB option offers no cost advantage relative to the RC case when CO_2 is vented, but for GHG emissions prices greater than US$40/t there is a significant production cost advantage for systems with CCS.

One reason why the economic benefit of coproduction is less for MTG systems than for FTL systems is that in the CTL case a shift from an RC to an OT configuration involves elimination of an energy- and capital-intensive autothermal reformer, whereas neither of the MTG recycle systems use autothermal reformers. Also, MTG systems need an extra water gas shift reactor to decarbonize the syngas stream going to the power plant, which is not needed for FTL systems.

OT systems for FTL and PB systems for MTG also offer less costly approaches to decarbonizing power than stand-alone power systems. To see this consider the cost of GHG emissions avoided (US$/tCO$_2$-eq),
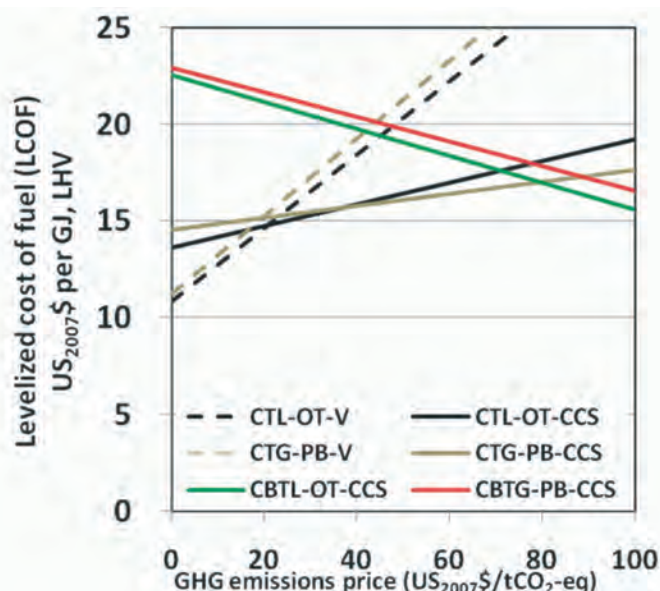
which is the GHG emissions price at which costs are equal for the –V and –CCS system configurations, i.e., the minimum GHG emissions price needed to induce CCS by market forces. This minimum GHG emissions price for both FTL and MTG systems is ~US$20/tCO$_2$-eq (Figures 12.34 and 12.35) compared to US$45/t or more for stand-alone power systems (Figure 12.10). The reason for this large difference is that for synfuels production systems a substantial fraction of the carbon in the feedstock has to be removed from the shifted syngas upstream of synthesis as a natural part of the part of the process of making synthetic fuels. Moreover, in the FTL cases removal of the extra CO_2 downstream of synthesis is not very costly because no extra water gas shift reactors are required.

Figure 12.36 shows the LCOFs for all six OT and PB systems considered as a function of the GHG emissions price, based on the performance information presented in Table 12.22 and the additional economic information presented in Table 12.23. An important feature of the curves presented in Figure 12.36, is the rapid rate of decline in LCOF with GHG emissions price for both the CBTL-OT-CCS system and the CBTG-PB-CCS system – in stark contrast to the flat LCOF curves for the corresponding RC systems presented in Section 12.4.3. This rapid rate of cost reduction reflects the rising value of decarbonized electricity with GHG emissions price (Figure 12.10). As a result of this sharp decline the LCOFs at US$100/tCO$_2$-eq are US$15.6/GJ$_{LHV}$ (US$1.9/gallon of gasoline equivalent) for FTL via CBTL-OT-CCS (73% of the LCOF for FTL via CBTL-RC-CCS) and US$16.6/GJ$_{LHV}$ (US$2.0/gallon of gasoline equivalent) for gasoline via CBTG-PB-CCS (80% of the LCOF for gasoline via CBTG-RC-CCS). In both instances the liquid fuels are characterized by near-zero net GHG emissions, and large quantities of decarbonized coproduct power are provided.

Table 12.23 | Capital cost and production cost estimates (US$_{2007}$$) for coal and coal + biomass to electricity + FTL or MTG.

CO$_2$ vented or captured >>>	CTL-OT-V	CTL-OT-CCS	CTG-PB-V	CTG-PB-CCS	CBTL-OT-CCS	CBTG-PB-CCS
Coal input rate, MW HHV	7559	7559	6549	6549	1011	1651
Biomass input rate, MW HHV	0	0	0	0	661	661
Liquids production rate, MW LHV	2256	2256	2100	2100	508	743
LPG production rate, MW LHV	0	0	202	202	0	68
bbl/day crude oil products displaced, excl. LPG	35,706	35,706	32,579	32,579	8036	11,582
Plant capital costs, million US$_{2007}$$						
Air separation unit (ASU) + O$_2$ & N$_2$ compressors	711	742	681	675	217	270
Biomass handling, gasification & gas cleanup	0	0	0	0	335	353
Coal handling, gasification & quench	1468	1468	1301	1301	263	402
All water gas shift, acid gas removal, Claus/ SCOT	636	727	598	705	151	324
CO$_2$ compression	0	60	0	70	24	34
F-T synthesis & refining or Methanol synthesis	519	519	347	347	171	155
Naphtha upgrading or MTG synthesis & refining	71	71	359	359	29	190
Power island topping cycle	272	280	227	231	80	141
Heat recovery and steam cycle	713	708	597	622	155	219
Total plant cost (TPC), million US$_{2007}$$	4390	4574	4110	4310	1427	2086
Specific TPC, US$_{2007}$$/bbl/day	122,958	128,093	126,154	132,293	177,526	180,110
Levelized liquid fuel cost (US$_{2007}$$/GJ$_{LHV}$) at US$0/tCO2[a]						
Capital charges	10.57	11.01	11.75	12.32	15.26	16.77
O&M charges	2.74	2.86	3.05	3.20	3.96	4.35
Coal (at US$2.04/GJ$_{HHV}$; US$55/t, as received)	6.82	6.82	7.02	7.02	4.05	4.98
Biomass (at US$5/GJ$_{HHV}$; US$94/t, dry)	0.00	0.00	0.00	0.00	6.51	4.89
CO$_2$ transport and storage	0.00	0.73	0.00	0.86	1.22	1.22
Co-product electricity revenue (at US$60/ MWh)	-9.31	-7.82	-8.42	-6.67	-8.44	-7.22
Co-product LPG revenue (for US$100/bbl crude oil)	-	-	-2.20	-2.20	-	-2.09
Total liquid fuel cost, US2007$/GJLHV	**10.8**	**13.6**	**11.2**	**14.5**	**22.6**	**22.9**
Total liquid fuel cost, US$_{2007}$$/gallon gasoline eq (US$/gge)	1.3	1.6	1.3	1.7	2.7	2.8
Breakeven crude oil price, US$_{2007}$$/bbl[b]	47	63	48	63	112	102
Cost of CO$_2$ emissions avoided, US$_{2007}$$/tCO$_2$	-	21	-	20	24	21

a See note (b) of Table 12.6 for financial parameter assumptions.

b See note (b) of Table 12.16 for discussion of the breakeven oil price calculation for MTG cases.

12.6.3   Coproduction Economics from the Electricity Production Perspective

The economics discussed in the prior section focused on estimating the cost of making liquid fuels via coproduction systems given assumed prices for the electricity coproducts. Alternatively, electricity production costs can be estimated based on assumed liquid fuel selling prices.[30] This alternative approach for evaluating the economics of

30 Here it is assumed that the synfuels are sold at the wholesale (refinery-gate) prices for the crude oil products displaced, including the valuation of the fuel cycle-wide GHG emissions for these products. The relevant GHG emissions for the crude oil products displaced are given in Table 12.15, note (c).

Table 12.24 | Alternative systems with 550 MW$_e$ of electric power capacity.

Technology	Primary energy input, MW (HHV)	Biomass input, kt/y (%, HHV basis)	FTL output, barrels /day (kt/year)	CO$_2$ stored, Mt/yr (% of feedstock C stored)	TPC, million US$_{2007}$$	GHGI[a]
Sup PC-V	1410	0	0	0	894	1.00
CIGCC-CCS	1780	0	0	3.62 (88)	1460	0.15
CTL-OT-V	3300	0	15,600 (658)	0	2200	1.31
CTL-OT-CCS	3930	0	18,600 (783)	5.01 (52)	2570	0.70
CBTL1-OT-CCS	3810	710 (12)	18,100 (763)	4.96 (53)	2630	0.50
CBTL1-OTA-CCS	4820	370 (5)	22,800 (963)	7.58 (64)	3300	0.50

a   GHGI = system wide life cycle GHG emissions for production and consumption of the energy products divided by emissions from a reference system producing the same amount of liquid fuels and electricity. Here the reference system consists of electricity from a stand-alone new supercritical pulverized coal power plant venting CO$_2$ and equivalent crude oil-derived liquid fuels. For details, see Table 12.15, note (c).

coproduction is of interest for three important reasons: (i) the incremental cost for carbon capture and storage is much less than for stand-alone power plants because, as already noted in Section 12.6.2, much CO$_2$ must be removed from syngas prior to synthesis as a natural part of fuels manufacture, so that capture costs are low; (ii) the economics of power generation are attractive at current and prospective high oil prices, resulting in a huge credit against the cost of electricity generation; and (iii) these systems can defend high capacity factors and force down capacity factors of competing technologies in economic dispatch competition. Coproduction is considered here for systems making Fischer-Tropsch liquids. First, we consider coproduction in the context of an evaluation of alternative options for new coal-using power plants (Section 12.6.3.1), with potential applications in China (Section 12.6.3.2). Second, we consider coproduction as an option for repowering old coal power plant sites (Section 12.6.3.3), with potential applications in the United States (Section 12.6.3.4).

12.6.3.1   XTL vs Stand-alone Power Options for New Plant Construction

Table 12.24 lists key system characteristics for four coproduction options and two conventional stand-alone power options – each of which is designed to have 550 MW$_e$ of electric generating capacity. The reference technology is a new supercritical coal power plant that vents CO$_2$ (sup PC-V), the least costly option for new stand-alone coal power plants in the absence of a carbon constraint (see Section 12.2.2). Also listed is a coal integrated gasification combined cycle plant with carbon capture and storage (CIGCC-CCS), currently the least costly CCS option for new stand-alone bituminous coal power plants (Section 12.2.3). The CTL-OT options are identical to those considered in the previous two sub-sections except that the scales have been adjusted to 550 MW$_e$ of electric capacity.[31] Two options are considered that involve coprocessing just enough biomass to reduce the system GHGI to 0.5. Biomass

accounts for 12% of energy for one of these options, CBTL1-OT-CCS, which involves capturing only the naturally concentrated streams of CO$_2$ in the syngas[32] (accounting for 53% of carbon in the feedstock). Biomass accounts for 5% of energy input for the other option, CBTL1-OTA-CCS, which involves more aggressive CO$_2$ capture[33] (accounting for 64% of carbon in the feedstock). Thus the same GHG emissions mitigation level is realized in one case by using more biomass and in the other by capturing more CO$_2$.

For each of these options, curves for the levelized cost of electricity (LCOE) vs GHG emissions price is shown in Figure 12.37 for a levelized crude oil price of US$90/bbl, for US economic conditions. This is the oil price for the period 2020–2030 as projected by the IEA for a future in which the global community is then on a course aimed at stabilizing the atmospheric GHG concentration at 450 ppmv (IEA, 2009b).

Several notable observations can be made about the curves in Figure 12.37:

- A GHG emissions price of only ~US$10/t is needed to induce a transition from CTL-OT-V to CTL-OT-CCS. In contrast a GHG emissions price of more than US$50/t is needed to induce a transition in stand-alone power generation from sup PC-V to CIGCC-CCS.

- The LCOE curves for CBTL1-OT-CCS and CBTL1-OTA-CCS lie nearly atop each other, meaning the extra capital cost for the more aggressive capture option is largely compensated by the lower fuel cost.[34]

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31 In adjusting plant scales it is assumed that system conversion efficiencies do not change, but capital cost scale economy effects are taken into account.

32 Both upstream and downstream of synthesis.

33 In the CBTL1-OT-CCS case, C1 to C4 gases in syngas downstream of synthesis are burned in the gas turbine combustor, thereby generating CO$_2$ that is vented to the atmosphere on the power island. In the CBTL1-OTA-CCS case an autothermal reformer and a water-gas-shift reactor are inserted downstream of synthesis to convert most of these C1 to C4 gases to mainly CO$_2$ and H$_2$ (see Figure 12.31). The extra CO$_2$ thus created is captured and stored. In this case the gas burned to make electricity is mostly H$_2$. For additional details regarding this "autothermal reforming" option for once-through (OT) systems, see Liu et al., 2011a.

34 The assumed (HHV) fuel prices are $2.04/GJ for coal and $5.0/GJ for biomass.
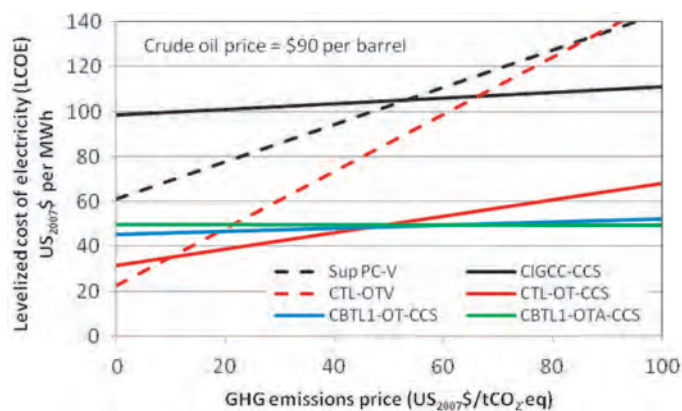
Figure 12.37 | Levelized cost of electricity (LCOE) for crude oil at $90/bbl for the electric power options described in Table 12.24. (See Table 12.6, note (b) for financial parameter values assumed.) The IEA (2009b) projects that if the global community were to pursue a GHG emissions trajectory consistent with stabilizing the atmospheric GHG concentration at 450 ppmv the world oil price would be flat at US$90/bbl, 2020–2030, considerably lower than its projection of the world oil price for its Reference Case (BAU) scenario.

- Although not shown in the figure, the LCOE for coproduction systems declines sharply with the crude oil price: for each US$10/bbl increase in the crude oil price the LCOE at a GHG emissions price of US$0/t is reduced by US$12/MWh for CTL-OT-V and by US$17/MWh for CBTL1-OTA-CCS.

- The LCOE for CBTL1-OTA-CCS is lower than for CTL-OT-CCS when the GHG emission price is US$57/tCO$_2$-eq.

The LCOE values represented by these curves are for design capacity factors of 85% for power only systems and 90% for coproduction systems. In a market economy, however, capacity factors are determined not by the design engineers but rather by economic dispatch competition. Once a power plant is built, its capital cost (*a sunk cost*) is not taken into account in the determination of the merit order dispatch on an electric grid. The dispatcher operating the grid determines, on the basis of competitive bids, the order in which plants are dispatched to meet electricity demand – with those plants being dispatched first that offer to sell electricity at the lowest price. It is worthwhile for a power generator to bid to sell electricity as long as the revenue it gets from power (in US$/MWh) is not less than its short run marginal cost of producing electricity (SRMC, which excludes sunk costs). This minimum acceptable selling price for the generator is called the minimum dispatch cost (MDC).

As power generators, the XTL-OT plants considered here were designed as "must-run" baseload units. Their MDC depends on the oil price: oil revenues reduce the revenue required from electricity. The MDC is very low for coproduction systems at sufficiently high oil prices. In the CBTL1-OTA-CCS case, with zero GHG emissions price the MDC is the same as for sup PC-V if the crude oil price is US$37/bbl, and the MDC falls to zero when the crude oil price is US$51/bbl. Thus coproduction will be able to defend high capacity factors in economic dispatch competition

and force down the capacity factors of competing technologies as their deployment on the electric grid increases.

12.6.3.2   Thought Experiment for China

Coproduction technologies with CCS can be effective in addressing simultaneously climate change and energy security challenges. To illustrate these benefits of coproduction strategies, a thought experiment is constructed in which it is imagined that all new power generation in China over the period 2016–2030 is shifted from the business-as-usual path of sup PC-V to a CCS path – considering for CCS, in turn, the CIGCC-CCS, CTL-OT-CCS, and CBTL1-OTA-CCS options listed in Table 12.24. Although none of these alternatives to sup PC-V have been built, all system components for these three options are either commercial or commercially ready, so it would be technically feasible to deploy each of these options commercially beginning later in this decade.[35] The aim of the thought experiment is to gain a better understanding of the strategic implications of pursuing coproduction options for power generation.

There are several reasons for focusing on China for this power-sector oriented thought experiment that are similar to the rationale for the China clean cooking fuel thought experiment discussed in Section 12.5.3.1:

- China has powerful reasons for becoming a world leader in identifying and pursuing low-cost approaches to decarbonizing coal energy conversion such as via deployment of coproduction systems with CCS, as suggested by Figure 12.37.[36] China is the world's largest consumer of coal, the most carbon-intensive fossil fuel, accounting for 48% of world coal consumption in 2010. And the expectation is that under business-as-usual conditions coal demand will continue to grow in China (IEA, 2009b).

- China has a strong incentive to explore alternatives to oil imports. It has evolved from being a net oil exporter in the early 1990s to being the world's second largest consumer of imported oil in 2010, with the expectation of continued rapid oil import growth.

- China has more experience with coal gasification technology than any other country. Essentially all of this experience is in China's chemical process industry, which is largely based on coal because of the scarcity of China's oil and gas resources. There are nearly 400 operating and planned coal-based chemical plants in China using

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35 The modeling reported above for the CBTL1-OTA-CCS option (coprocessing 5% biomass) is for a system with separate gasifiers for coal and biomass. For systems deployed in this decade, it is more likely that a single suitable coal gasifier that can cogasify modest quantities of biomass with coal would be deployed instead.

36 Of course the LCOEs shown in this figure are only suggestive for China, because they were estimated for the United States, not Chinese, economic conditions. Moreover, the LCOEs for first of a kind plants would be higher than those shown even in the US case, because the indicated costs are for Nth of a kind plants.
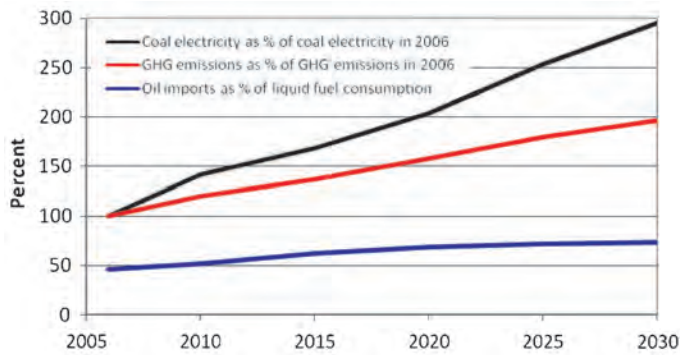
Figure 12.38 | Business-as-usual (BAU) projection by US Energy Information Administration of China's energy future, 2006–2030. Source: US EIA, 2009a.

coal gasification (Zheng et al., 2010); most are ammonia plants but there are also methanol plants, other chemical plants, and a few synthetic fuels plants. Evolving from the manufacture of chemicals and synthetic fuels in such a relatively mature gasification-based industry to the coproduction of liquid transportation fuels and electricity represents a relatively modest step forward from a technological perspective.

• China has one of the world's fastest-growing economies, and rapidly growing economies are the most favorable theatres for technological innovation.

The starting point for the thought experiment is the US Energy Information Administration's Reference Scenario for China (US EIA, 2009a), in which it is projected that between 2006 and 2030 coal power generation will almost triple, total national GHG emissions will almost double, and oil imports will increase 3.4 times from 42% to 75% of liquid fuel consumption (Figure 12.38).

Implications of the thought experiment for carbon mitigation are indicated in Figure 12.39, which shows that in 2030, China's GHG emissions would be less than for the business-as-usual case by the amounts 1.3 GtCO$_2$-eq/yr, 1.9 GtCO$_2$-eq/yr, and 2.3 GtCO$_2$-eq/yr for the CTL-OT-CCS, CIGCC-CCS, and CBTL1-OTA-CCS trajectories, respectively. That the CBTL1-OTA-CCS path leads to 20% more GHG emissions mitigation than the CIGCC-CCS path even though GHGI = 0.5 for CBTL1-OTA-CCS compared to 0.15 for CIGCC-CCS arises because the coproduction option reduces emissions for liquid fuels as well as for electricity.

Implications of the thought experiment for China's oil imports are indicated in Figure 12.40. For the business-as-usual and CIGCC-CCS trajectories, oil imports grow from 162 to 551 Mt/yr (3.3 to 11.2 million bbl/day) between 2006 and 2030 but are reduced by 2030 to + 33 and − 86 Mt/yr (+ 0.68 and − 1.74 million bbl/day) for the CTL-OT-CCS and CBTL1-OTA-CCS trajectories, respectively.
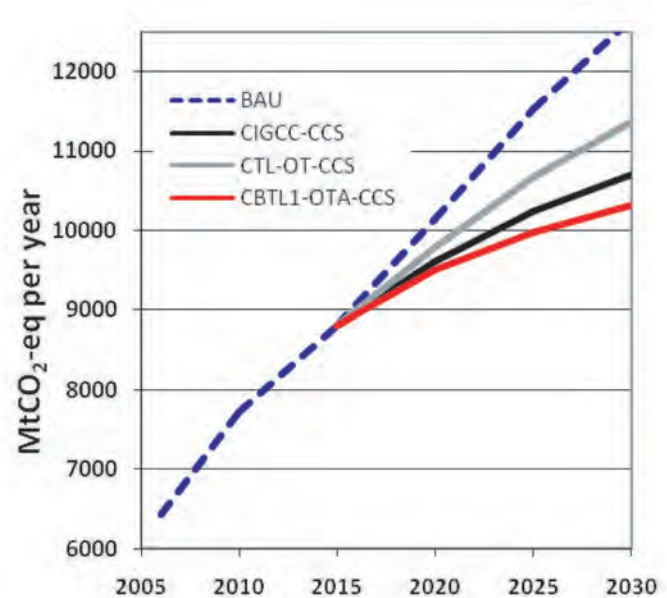

Figure 12.39 | GHG emissions for China: for the BAU scenario based on US EIA (2009a) and for the three thought experiment variants discussed in the main text.
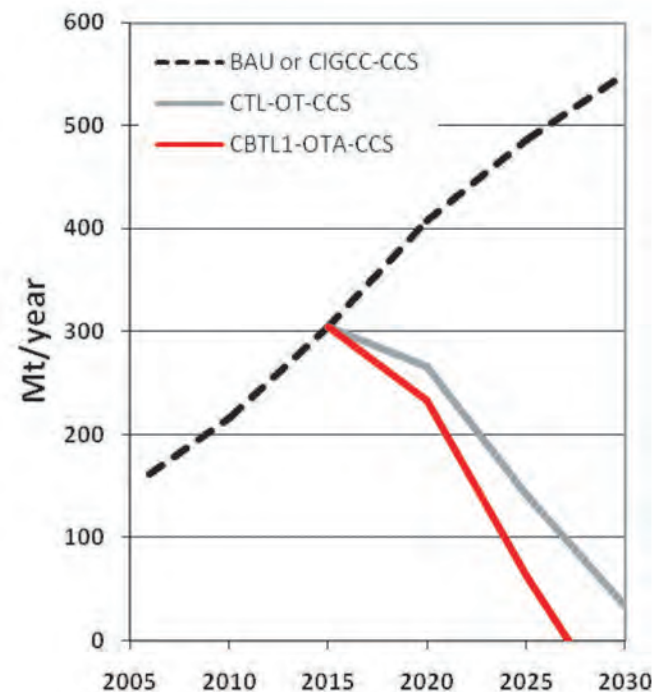

Figure 12.40 | Oil imports for China: for the BAU scenario based on US EIA (2009a) and for the three thought experiment variants discussed in the main text.

In 2030 the biomass required for the CBTL1-OTA-CCS trajectory would be 235 Mt/yr – some 62% of the crop residue supplies potentially available for energy applications in China in 2010 (Li et al., 1998).

The coproduction trajectories might well require a substantial increase in China's coal imports. However, coal imports are likely to pose less of an energy security challenge than oil imports, and the reduced oil import bill is likely to more than compensate for the increased cost of coal imports.[37]

Of course, the economics of coproduction relative to conventional power must be evaluated under China's economic conditions, and the coal/biomass supply implications of the thought experiment must be well understood before one can have a high level of confidence that this would be a cost-effective and otherwise attractive energy strategy for China. But the thought experiment suggests that investigating these issues would be worthwhile.

12.6.3.3 XTL-OT Systems as Repowering Options for Existing Coal Power Plant Sites

Decarbonization will be needed not only for new coal power plants but also for existing power plant sites. In industrialized countries such as the United States, the focus will be on existing power plant sites because overall electricity demand growth is expected to be slow. In this section, five systems providing Fischer-Tropsch liquid transportation fuels as coproducts of electricity and three stand-alone power systems are considered as repowering decarbonization options for sites of existing written-off pulverized coal plants that vent CO_2 (WO PC-V). The coproduction options include both coal-only systems and systems that coprocess coal and biomass. Each of these repowering options is compared to a CCS retrofit of the WO PC-V plant (PC-CCS retrofit), based on analyses in Williams et al. (2011) and Liu et al. (2011a). Key system characteristics for these ten systems are presented in Table 12.25. The alternative systems are compared with regard to GHG mitigation performance, CO_2 storage requirements, energy penalties for CCS, site water requirements, and economics. However, the emphasis is on GHG emissions mitigation performance and economics.

A narrow definition of repowering is scrapping an existing power plant but keeping the site and its infrastructure for use by a new facility. Not all sites can accommodate repowering. There has to be enough space to accommodate all equipment associated with repowering, there have to be suitable CO_2 storage opportunities, and (for cases in which biomass is coprocessed with coal) biomass supplies have to be available. However, the definition of repowering is broadened somewhat to include also the option of abandoning the site entirely and rebuilding at a greenfield site if the targeted site is unsuitable. The economics change only relatively modestly in a shift from building a new plant at an existing site to building a new plant at a greenfield site. The economic benefits associated with saving the infrastructure are not taken into account.

For each of the ten options in Table 12.25 the LCOE vs GHG emissions price is shown in Figure 12.41 for US economic conditions. For the options involving CCS, it is assumed that the cost of CO_2 transport and storage is US$15/t for all options – higher than would be typical for new plant construction. For coproduction systems, the LCOE is evaluated for a levelized crude oil price of US$90/bbl, the oil price for the period 2020–2030 as projected in *World Energy Outlook* 2009 (IEA, 2009b) for a future in which the global community is then on a course aimed at stabilizing the atmospheric GHG concentration at 450 ppmv.[38] As in the case of the larger-scale coproduction systems discussed in Section 12.6.3.1, LCOEs are very sensitive to the crude oil price.[39] To assess the risk from an oil price collapse, the breakeven crude oil price for the five coproduction repowering systems is shown as a function of GHG emissions price in Figure 12.42.[40]

Particular attention is given to the five options for which GHGI is less than 0.20, in light of the fact that political leaders of many industrialized countries are targeting emissions reductions of 80% or more for their countries by mid-century.

Three of the coproduction systems were evaluated earlier from a fuels production perspective, though in some cases at different plant scales: CTL-OT-V, CTL-OT-CCS, and CBTL-OT-CCS (Figure 12.31). One of the coproduction systems not discussed earlier is CBTL-OTA-CCS (also depicted in Figure 12.31), which has a GHGI below 0.1, as does CBTL-OT-CCS (0.077 vs 0.083, see Table 12.25) but realizes the low emission rate via more aggressive CO_2 capture (65% vs 54% of the C in the feedstock is captured) along with a lower biomass input percentage (29% vs 40%). The other new coproduction option considered is CBTL2-OT-CCS for which a GHGI = 0.5 is realized with about 9% biomass input. This option is included because systems involving such a modest percentage of biomass in the feed could be ready for deployment in commercial-scale demonstration projects in this decade.

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37 The extra coal required for the CBTL1-OTA-CCS option amounts to 2.1 tonnes of coal equivalent (tce) per tce of Fischer-Tropsch liquid transportation fuels produced. The IEA projects for its Reference Scenario that the coal import price for OECD countries will be $100/t in 2020 and $110/t in 2030 (IEA, 2009b). For China, the cost of oil imports avoided for $90/bbl of crude oil would be 1.7 times the increased cost of coal imports if coal imported into China were to cost $110/t.

38 For this evaluation it is assumed that: i) the synthetic liquid fuel coproducts are sold at the wholesale (refinery-gate) prices of the crude oil-derived products displaced (7.90 and 8.51¢ per liter refining markups for diesel and gasoline, respectively), and ii) selling prices increase with GHG emissions price by an amount equal to the fuel-cycle-wide GHG emission rates for these crude oil-derived products times the emissions price.

39 At a GHG emissions price of $0/t, the LCOE increases by an amount ranging from $12/MWh (for CTL-OT-V) to $16/MWh (for CBTL-OTA-CCS) for each $10/bbl reduction in the levelized crude oil price.

40 The breakeven crude oil price is a metric for evaluating the economics of coproduction systems from a synfuel producer's perspective. It is the crude oil price at which the levelized costs of manufacturing the synfuel coproducts equal the wholesale (refinery-gate) prices of the crude oil products displaced. In this calculation it is assumed that the electricity coproduct is sold at the average selling price for US electricity generation in 2007 ($60/MWh) augmented by the value of the US average electric grid emission rate in 2007 (638 kgCO2-eq/MWh). Figure 12.10 shows this electricity price vs GHG emissions price.

Table 12.25 | CCS retrofit and repowering options for sites of written-off PC-V plants.

	Capacities[d]				Energy penalty for CCS[e] (%)	Site raw H$_2$O use at full output,[f] liters/s (% of WO PC-V)	GHGI[g]	CO$_2$ stored, Mt/yr (% of input C stored)	TPC[h], million US$_{2007}$$
	Inputs		Outputs						
	Fuel, MW, HHV	Biomass, Mt/yr (%, HHV basis)	Electricity, MW$_e$	FTL bbl/day (MW, LHV)					
WO PC-V[a]	1613	0	543	0	–	310 (100)	1.00	0	0
PC-CCS retrofit[a]	1613	0	398	0	36.4	413 (133)	0.19	3.48 (90)	426
Repowering options									
CIGCC-CCS[b]	1613	0	500	0	21.1	294 (95)	0.13	3.29 (88)	1369
CTL-OT-V[b]	1613	0	269	7,619 (481)	–	232 (75)	1.17	0	1235
CTL-OT-CCS[b]	1613	0	226	7,619 (481)	8.6	245 (79)	0.63	2.06 (52)	1280
CBTL2-OT-CCS[b]	1694	0.23 (8.8)	242	8,036 (508)	8.6	253 (82)	0.50	2.19 (53)	1348
CBTL-OT-CCS[b]	1671	1.0 (40)	257	8,036 (508)	8.5	237 (76)	0.083	2.26 (54)	1427
CBTL-OTA-CCS[b]	2272	1.0 (29)	287	10,861 (686)	17.1	271 (87)	0.077	3.71 (65)	1784
NGCC-V[c]	1102	0	560	0	–	113 (37)	0.42	0	321
NGCC-CCS[c]	1102	0	482	0	16.3	171 (55)	0.11	1.36 (90)	583

a System characteristics as developed in Simbeck and Roekpooritat, 2009.

b Source: Williams et al., 2011 and Liu et al., 2011a.

c System characteristics as developed by Woods et al., 2007.

d Capacities for systems using coal were determined by the following algorithms: i) Coal input rates cannot exceed the coal input rate of the WO PC-V plant displaced; ii) biomass input rates cannot exceed 1.0 Mt/year; iii) CBTL2-OT-CCS has the same FTL output capacity as CBTL-OT-CCS.

e For power-only systems, penalty = 100 x (η_v/ η_c – 1), where η_v and η_c are HHV plant efficiencies for –V and –CCS options, respectively. For XTL-OT-CCS options, penalty = 100 x (extra coal energy required via CIGCC-CCS to make up for lost power in shifting from –V → –CCS)/(coal energy use by XTL-OT-V).

f Raw water usage = consumption – water recycled; estimated by authors for gasification energy systems; based on Woods et al., 2007 for combustion energy systems, as discussed in the main text.

g GHGI = greenhouse gas emissions index = system wide life cycle GHG emissions for production and consumption of the energy products relative to emissions from a reference system producing the same amount of power and liquid fuels. In this instance the reference system consists of electricity from a WO PC-V power plant (for which the GHG emission rate is 998.8 kgCO$_2$-eq/MWh$_e$) and equivalent crude oil-derived liquid fuels (for which the GHG emission rate is 91.6 kgCO$_2$-eq/GJ).

h This is the total plant cost (TPC), or "overnight capital cost" (which excludes interest during construction).

A CIGCC system is included as a repowering option because, among currently available technologies, this option offers the lowest LCOE among stand-alone coal power systems in new construction applications (see Section 12.2.3). The NGCC is also given close attention in light of recent bullishness about US gas supplies (MIT, 2010).

Simbeck and Roekpooritat (2009) analyzed and estimated LCOEs for several CCS retrofit options based on near-term technologies and showed that a simple CCS retrofit (without plant modification) based on an amine post-combustion scrubber offers the lowest LCOE for a retrofit, although the alternatives would be less energy-intensive. The least-costly CCS retrofit option identified in Simbeck and Roekpooritat is adopted with some of the cost assumptions adjusted to enable self-consistent comparisons in the analytical framework of Williams et al. (2011) and Liu et al. (2011a).

The findings of this analysis for various alternatives to a WO PC-V plant are as follows:

PC-CCS retrofit: The CCS retrofit option is widely thought to be the preferred option if coal use is to persist under decarbonization. This option is by far the least disruptive of the status quo. Its main attraction is that it requires the least capital investment among decarbonization options that involve coal use (see Table 12.25). However, this option involves a huge 36% energy penalty for CCS mainly because of the large amount of heat required to regenerate the amine solvent after it has absorbed the CO$_2$ from flue gases in which its partial pressure is only 0.14 atmospheres. This high energy penalty gives rise to a large (~33%) increase in the water requirements for the site, which will often greatly limit the viability of this option. The high energy penalty also implies a high minimum GHG emissions price ~US$70/tCO$_2$-eq to induce via market forces a shift from WO PC-V to PC-CCS retrofit (see Figure 12.41).[41]

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41 The point at which the PC-CCS retrofit and WO PC-V curves cross determines the minimum GHG emissions price needed to induce CCS via market forces.
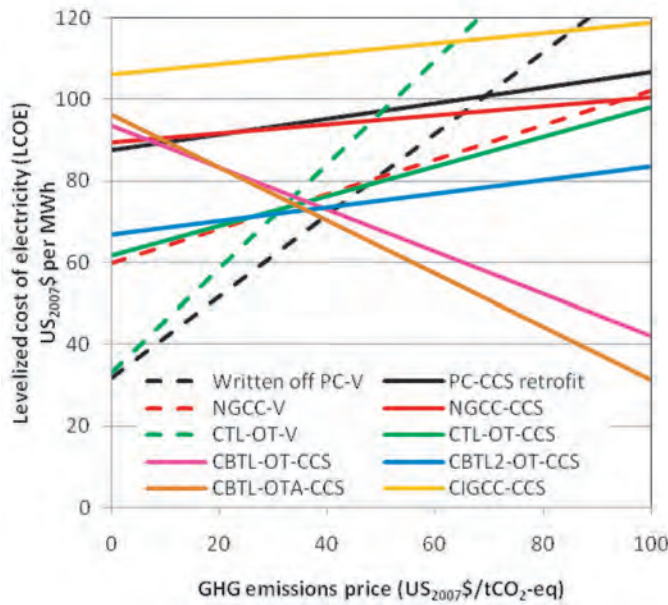
Figure 12.41 | Levelized cost of electricity (LCOE) vs GHG emissions price under US conditions for the alternative power options in Table 12.25 when the levelized crude oil price is US$90/bbl. (See Table 12.6, note (b) for financial parameter values assumed.) Source: based on Liu et al., 2011a; Williams et al., 2011.
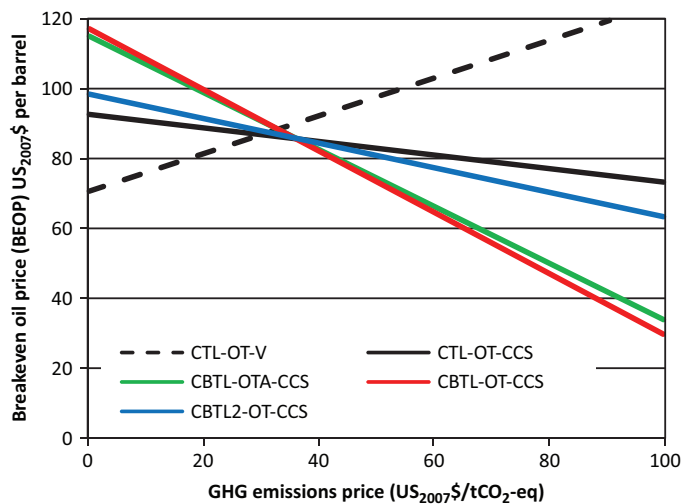

Figure 12.42 | Breakeven crude oil price (BEOP) vs GHG emissions price for the alternative coproduction systems in Table 12.25. (See Table 12.6, note (b) for financial parameter values assumed.) Source: based on Liu et al., 2011a; Williams et al., 2011.

Repowering via CIGCC-CCS: With pre-combustion capture, the energy penalty for CCS and water requirements are both reduced more than 40% relative to the PC-CCS retrofit (see Table 12.25). In part this is because the CO_2 is captured at high partial pressure from shifted syngas instead of from flue gases. But also the low water requirement reflects the fact that only ~1/3 of the power output of the combined cycle power plant is from the steam turbine, which requires the

consumption of water for condenser cooling purposes (the gas turbine topping cycle does not), and cooling water dominates water requirements in all cases. These technical advantages do not imply a lower LCOE for the CIGCC-CCS repowering option compared to the PC-CCS retrofit via post-combustion capture (see Figure 12.41), in contrast to the situation for new construction. This is largely because in this application the capital investment is ~three times that for the PC-CCS retrofit (see Table 12.25) whereas in new construction, where CIGCC-CCS does offer a lower LCOE, the capital cost for CIGCC-CCS is likely to be less than for a new pulverized coal plant with post-combustion capture (see Figure 12.10).

Repowering via NGCC: The natural gas combined cycle power plant venting CO_2 (NCCC-V) is the least capital-intensive and least water-intensive of the options shown in Table 12.25. But its carbon-mitigation potential (GHGI = 0.42) is far less than what is likely to be required by mid-century to realize the US goal of more than an 80% reduction in the nation's total GHG emissions. This implies that, if NGCC-V is deployed in the near term as a repowering option at WO PC-V plant sites, the NGCC-V would have to be replaced by NGCC-CCS (as a retrofit or via repowering option) at some point during this half-century. As shown by Figure 12.41 this option would be roughly competitive with a PC-CCS retrofit, and the energy penalty for CCS and water requirements would be less than half of those for a PC-CCS retrofit.[42] One serious economic challenge posed by the NGCC-CCS option is that the minimum GHG emissions price needed to induce CCS by market forces is nearly US$100/t (see Figure 12.41). Another relates to the prospect that it will be very difficult for NGCC-CCS to defend the high assumed 85% capacity factor in economic dispatch competition if there is much coproduction capacity on the electric grid because of the technology's high minimum dispatch cost compared to coproduction options (see Figure 12.43).[43] Still another problem posed by the NGCC-CCS option is that prospective natural gas supplies in the United States are likely to fall far short of what would be required to meet fully the decarbonization challenge posed by existing coal power plants, as discussed in Section 12.6.3.4.

Repowering via XTL-OT technologies: Though not a decarbonization option (GHGI = 1.18), CTL-OT-V is included here as a repowering option because it offers the least costly electricity at low GHG emissions prices.[44] Its inclusion highlights the GHG emissions prices needed to induce a transition to coproduction systems offering significant reductions in GHG emissions. Notably, for all coproduction options the energy

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42   This may seem surprising because, like the PC-CCS retrofit, CCS involves post-combustion capture and the CO_2 partial pressure in flue gases is much lower (0.04 atmospheres). The modest penalty arises in this case because the capture rate is only 0.38 t/MWh compared to 1.17 t/MWh for PC-CCS retrofit – reflecting the much lower carbon intensity of natural gas compared to coal.

43   See discussion of dispatch competition in Section 12.6.3.1.

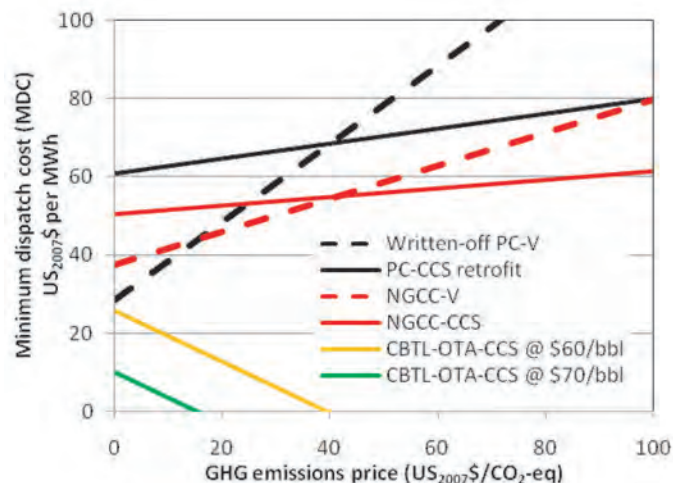44   At $0/t its LCOE is the same as for WO PC-V.

Figure 12.43 | Minimum dispatch cost (MDC) vs GHG emissions price for the alternative coproduction systems listed in Table 12.25. Source: based on Liu et al., 2011a; Williams et al., 2011.

penalty for CCS is one quarter to one half of that for the PC-CCS retrofit, and in all cases water requirements are less than two-thirds as much as for the PC-CCS retrofit. The CCS energy penalty is small largely because a substantial amount of CO_2 must be removed from syngas upstream of synthesis even in the absence of a carbon policy.[45] Water requirements are low for three reasons: (i) the low energy penalty for CO_2 capture; (ii) a significant part of the power output is from the gas turbine part of the power cycle, which does not require water for cooling (as in the NGCC and CIGCC cases); (iii) two thirds or more of the net energy output is in the form of liquid fuels, the production of which requires much less water than does electricity generation.

A notable feature of Figure 12.41 is that the coproduction options with CCS that do not offer deep reductions in emissions (CTL-OT-CCS (GHGI = 0.63) and CBTL1-OT-CCS (GHGI = 0.50)) are never the least costly electricity generation options. Rather, WO PC-V is the least costly option until the GHG emissions price reaches ~US$40/t, above which CBTL-OTA-CCS (GHGI = 0.077) is the least costly option.

It may seem counterintuitive that the more capital-intensive CBTL-OTA-CCS, which involves "aggressive" CO_2 capture, offers a lower LCOE than CBTL-OT-CCS at high GHG emissions prices. There are three reasons for this. First, the average feedstock price for CBTL-OTA-CCS (with 29% biomass) is 10% less than for CBTL-OT-CCS (with 40% biomass). Second, the capital intensity (in US$/kW$_e$) of CBTL-OTA-CCS falls from being 18% higher than for CBTL-OT-CCS when their FTL output capacities are the same to 12% higher when the CBTL-OTA-CCS output capacity is increased to the point where the biomass consumption rates are the same (1 Mt/yr) for these options. The net effect of the lower feedstock price and the higher capital intensity is that the LCOE is only 3% higher

for CBTL-OTA-CCS than for CBTL-OT-CCS at US$0/t. Third, the more rapid rate of decline of LCOE with GHG emissions price for CBTL-OTA-CCS arises because its FTL/electricity output ratio (and thus the credit for GHG emissions avoided by displacing crude oil derived products) is 21% higher for CBTL-OTA-CCS than for CBTL-OT-CCS.

A single XTL-OT plant requires an investment of US$1.2–1.8 billion (see Table 12.25). Investors will worry about the risk of oil price collapse, which is a very real concern because marginal oil production costs are lower than US$90/bbl, the assumed oil price for the LCOE calculations presented in Figure 12.41. In particular, successful market establishment of coproduction technologies could plausibly drive down oil prices.

How might investors be protected against the risk of oil price collapse? To help address this question, Figure 12.42 was constructed to show the breakeven crude oil prices for the alternative coproduction technologies. This figure shows that those who invest in XTL-OT-CCS technologies that coprocess biomass at high rates (29–40%) would be protected against falling oil prices down to less than US$60/bbl if the average GHG emissions price were US$69/t, the minimum GHG emissions price needed to make a PC-CCS retrofit competitive with WO PC-V. In contrast, the XTL-OT-CCS options that coprocess no or only modest amounts of biomass offer only modest protection against the risk of oil price collapse. Thus, the combination of a strong carbon mitigation policy and a high rate of biomass coprocessing is key to simultaneously realizing deep reductions in GHG emissions and enhancing transportation fuel security.

Finally, an attractive attribute of XTL-OT systems is their low minimum dispatch costs (MDCs), which would enable them not only to defend high capacity factors in economic dispatch competition but also would make it possible for them to drive down the capacity factors of competing technologies as XTL-OT market penetration expands. Figure 12.43 illustrates the point for CBTL-OTA-CCS. At crude oil prices of US$37/bbl and US$57/bbl, respectively, this system would have MDCs that are the same as for PC-CCS retrofits and WO PC-V plants when the GHG emissions price is $0/tCO$_2$eq. For US$74/bbl crude oil the MDC = US$0/MWh for this system.

12.6.3.4   Repowering Thought Experiment for the United States

The outstanding economics at sufficiently high oil and GHG emissions prices of coproduction systems coprocessing coal and substantial amounts of biomass suggest that it would be worthwhile exploring the repowering thought experiment for the United States that follows.

The point of departure for the thought experiment is an assumption that the United States enacts public policy mandating that all coal-fired power plants be retrofitted or repowered at a linear rate over the period 2016–2050, until all existing coal power plant capacity is replaced. Since the projected level of coal capacity for 2015 is 322 GW$_e$ (US EIA, 2010b), the coal power retrofit/repowering rate would be 9.2 GW$_e$/yr during

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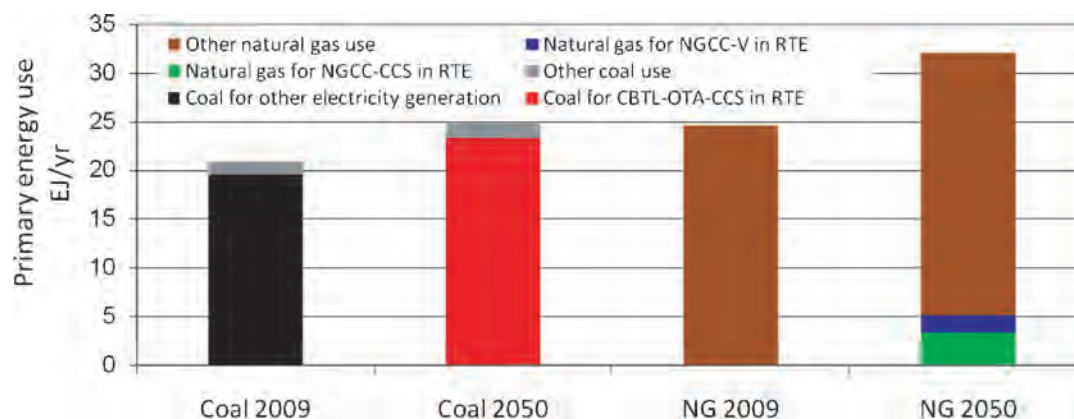45   See caption to Figure 12.31.

Figure 12.44 | Coal and natural gas demand implications of US repowering thought experiment (RTE).

2016–2050. It is further assumed that market forces are effective in deploying the least-costly options and that crude oil and GHG emissions prices are sufficiently high to make CBTL-OTA-CCS technology the least costly power generation option, and to make both NGCC-V and NGCC-CCS technologies less costly options than both the WO PC-V and PC-CCS retrofit options. (One set of prices for which these conditions would be met is US$90/bbl of crude oil and a GHG emissions price greater than US$50/t, see Figure 12.41.) Also it is assumed that under repowering conditions a site would not produce any electricity for a period of five years, which is the time required to bulldoze the existing site and build a new repowering unit there. Under these conditions, it would be cost-effective to retire WO PC-V plants, no PC-CCS retrofits would be deployed, and the following would be a cost-effective scenario:

- During 2016–2020, greenfield NGCC-V plants come on line at a rate of 9.2 GW$_e$/yr to exactly compensate for coal power plant retirements.

- During 2021–2050, each year 9.2 GW$_e$ of coal power capacity is replaced by 4.9 GW$_e$ of CBTL-OTA-CCS repowering capacity + 4.3 GW$_e$ of NGCC-CCS makeup capacity built at greenfield sites to compensate for coal plant retirements.

The following are the results of this repowering thought experiment, assuming for simplicity that over the period to 2050 the US energy economy is frozen at the level of energy activities of 2015 as projected in US EIA (2010b) for all energy sectors except coal power:

- GHG emissions for 1810 TWh of electricity (all coal electricity in 2015) would be reduced in 2050 by 1.61 GtCO$_2$-eq/yr (85% reduction).

- GHG emissions for 5.4 million barrels/day of gasoline equivalent liquid transportation fuels would be reduced in 2050 by 0.84 GtCO$_2$-eq/yr (92% reduction), bringing the total GHG emissions avoided in 2050 to 2.45 GtCO$_2$-eq/yr.

- Replacement electricity generation in 2050 would be made up of 64% CBTL-OTA-CCS, 22% NGCC-CCS, and 14% NGCC-V.

- The CO$_2$ storage requirements in 2050 would be 2.04 GtCO$_2$ (93% via CBTL-OTA-CCS and 7% via NGCC-CCS).

- The biomass required for CBTL-OTA-CCS plants in 2050 would be 508 Mt/yr.

- US coal and natural gas use in 2050 would be, respectively, 19% and 31% higher than in 2009 (see Figure 12.44).

- The total investment required for the repowering thought experiment through 2050 is US$1.1 trillion (see Figure 12.45).

The results of the repowering thought experiment have some important strategic implications:

- The low C transportation fuels produced would be at about the level of transportation fuels produced from US domestic crude oil in 2009.[46]

- The total CO$_2$ storage requirements in 2050 would be about the same if PC-CCS retrofits were pursued[47] instead of this repowering strategy, even though the retrofit strategy would involving decarbonising only coal power – a startling result that reflects largely the difference in energy penalties for CCS (36% for PC-CCS retrofits vs 17% and 16% for CBTL-OTA-CCS and NGCC-CCS, respectively, see Table 12.25).

- The potentially available biomass resources converted using CBTL-OTA-CCS systems could produce much more low-GHG liquid fuel than if converted to cellulosic ethanol, because producing 1 GJ of

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46   Crude oil was produced in the United States in 2009 at a rate of 5.36 million barrels per day, from which 5.18 million bbl/day of gasoline equivalent transportation fuels (gasoline, diesel, and jet fuel) were produced.

47   In the CCS retrofit strategy 73% of the system capacity and 97% of the system generation in 2050 are provided by PC-CCS retrofit plants, while 27% of system capacity and 3% of generation are provided by NGCC-CCS. The CO$_2$ storage rate in 2050 is 2.08 GtCO$_2$, 99% is via PC-CCS retrofit plants.
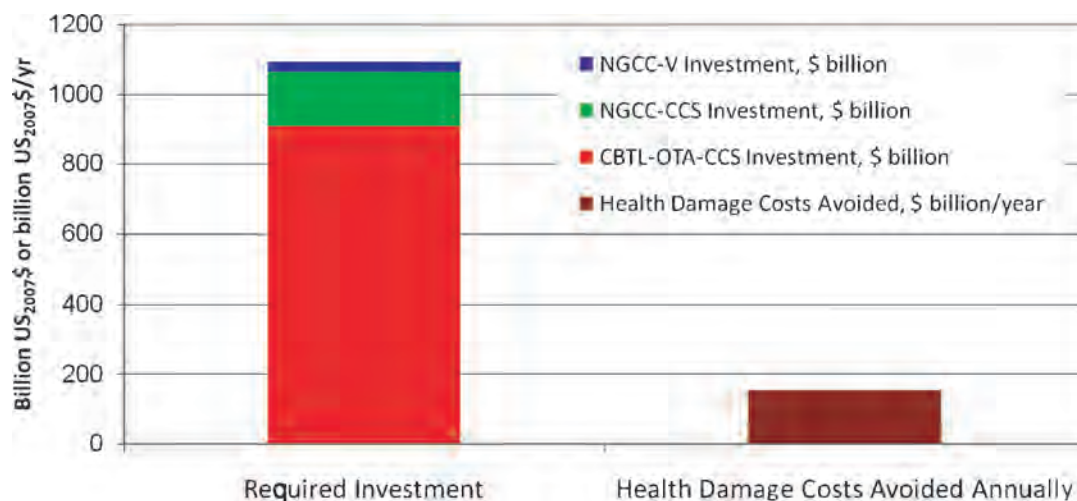
Figure 12.45 | The simple payback on the total new plant investment, 2016–2050, for the RTE would be about seven years if the sole benefit considered is the reduced public health damage costs from reduced PM$_{2.5}$ air pollution. (See Table 12.9.)

Fischer-Tropsch transportation fuels via CBTL-OTA-CCS requires only 36% as much biomass as producing 1 GJ of cellulosic ethanol (see Figure 12.33). If the same amount of synthetic low-carbon liquid fuel as would be produced in 2050 in the repowering thought experiment were instead produced as the energy equivalent amount of cellulosic ethanol, some 1400 Mt/yr of biomass would be required (see Section 12.6.4). In 2005 it was widely believed that the United States has 1300 Mt/yr of prospective biomass supplies for energy. Concerns about food/fuel competition, indirect land-use impacts, and biodiversity loss have reduced the estimate of sustainable US biomass production to ~500 Mt/y (the level for the repowering thought experiment in 2050) if growing dedicated energy crops on good cropland is not allowed – according to the *America's Energy Future* Study of the US National Research Council (AEFP, 2009).

- The incremental natural gas supply required for the RTE beyond that for 2009 is 7.5 EJ/yr by 2050 and 5.9 EJ/yr for the intermediate year 2035. The latter is much less than the 9.4 EJ/yr of incremental shale gas which the Energy Information Administration estimates will be available by 2035 (AEFP, 2009). However, US EIA also projects substantial reductions for other gas supplies in the period to 2035 (see Figure 12.46), so that the net incremental gas supply in 2035 relative to 2009 is only 3.1 EJ/yr, which is enough to satisfy only 52% of the natural gas requirements[48] for the RTE by 2035, assuming all the incremental gas is dedicated to power generation.

- Alternative renewable electricity supplies would have to grow four times between 2009 and 2035 if all of net incremental gas supply projected for 2035 were used for power generation and the short-

fall in electricity generation were provided entirely instead by these renewable sources.

- The simple payback on the investment would be ~seven years (see Figure 12.45) if the only benefit considered for this repowering strategy were the reduced health damage costs from PM$_{2.5}$ air pollution (see Table 12.9).

12.6.4   Alternative Approaches for Low GHG-emitting Liquid Fuels Using Biomass

The analysis in the preceding section indicates that coproduction systems with CCS that coprocess ~30% biomass would be very competitive as repowering options for sites of old coal power plants at high oil and GHG emissions prices, while simultaneously providing synthetic liquid fuels with near zero net GHG emissions. But biomass is a scare resource. How does this biomass use option compare to other options for providing low-GHG-emitting transport fuels? This question must be addressed to understand better the extent to which biomass coprocessing with coal and CCS for coproduction systems should be given priority in public policies relating to future uses of biomass for energy.

To address this question, the CBTL-OTA-CCS option for which 29% of the feed (HHV basis) is biomass is compared to alternative ways to use biomass to provide low-C fuels. Attention is focused on six alternatives. One alternative (BIGCC-CCS) was discussed in Section 12.2.3. The negative emissions with BIGCC-CCS provide "room in the atmosphere" for emission from some petroleum-derived fuels. Three alternatives (CBTL-RC-CCS, BTL-RC-V, BTL-RC-CCS) were discussed in Section12.4.3. Two new systems not yet considered, are also introduced as alternatives: (i) a future cellulosic ethanol option (EtOH-V), which is currently a high priority for biofuels development in the United States; and (ii) a –CCS variant of this (EtOH-CCS), see Box 12.3. In total, seven options are

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48 Since the natural gas demand for NGCC-V systems deployed during 2016–2020 would have to be satisfied first in the RTE, only 15% of the natural gas needed for NGCC-CCS systems by 2035 would be available from net incremental natural gas supplies.
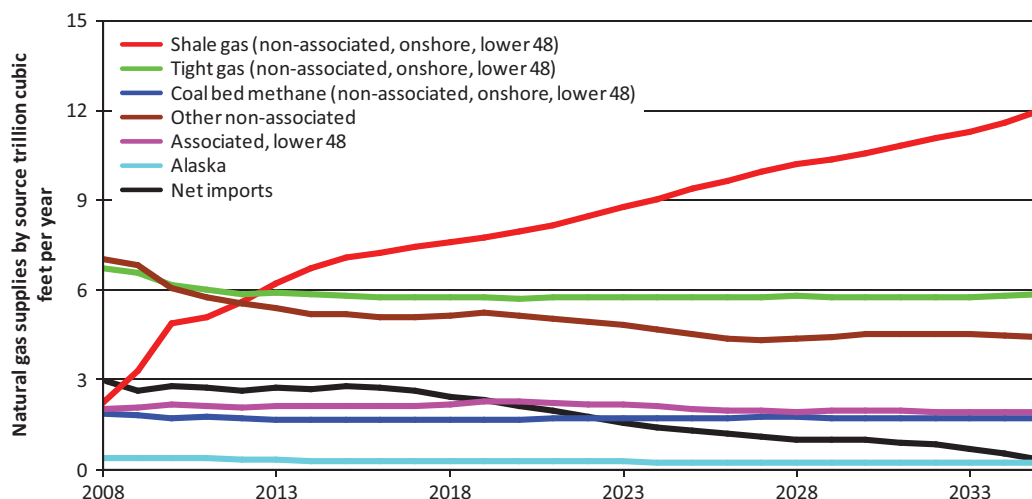
Figure 12.46 | Outlook for natural gas supplies in the United States. To convert cubic feet to cubic meters, divide by 35.3. Source: modified from US EIA, 2010a.

Box 12.3 | Prospective Cellulosic Ethanol Technologies

EtOH-V: The main cellulosic ethanol option considered here is the future switchgrass-to-ethanol option analyzed in a study by America's Energy Future Panel (AEFP, 2009), for which the estimated yield is 80 gallons of ethanol (EtOH) per dry short ton (334 L/t). For reference, the yield from switchgrass with currently understood technology is ~69 gallons per dry short ton (288 L/t). That study estimated a capital cost of $US_{2007}$$156 million for a plant producing 40 million gallons (156 million liters) of ethanol annually (an output capacity of 1941 bbl/day, or 309,000 L/day, of gasoline equivalent).

EtOH-CCS: It is feasible to carry out CCS for EtOH production if there are adequate CO_2 storage opportunities nearby because in the fermenter 1 mol of CO_2 is generated in a pure stream for each mol of EtOH) produced. The capital cost penalty for this CCS option is modest (see Table 12.26).

presented in Table 12.26. In all cases it is assumed that the feedstock is switchgrass consumed at a rate of about 0.5 Mt/yr dry biomass – the reference scale assumed for future cellulosic ethanol plants (EtOH-V) assessed in a recent United States National Research Council report (AEFP, 2009).

Six of the plants listed in Table 12.26 involve CCS, but the CO_2 capture rates vary by a factor of 17 from the lowest (EtOH-CCS) to the highest (CBTL-OTA-CCS). To illustrate the impact of capture rate on system economics it is assumed in all CCS cases that the CO_2 is transported 100 km and stored in a saline formation 2 km underground, and that the maximum CO_2 injectivity is 2500 t/day per well. The CO_2 transport and storage cost model cited by Liu et al. (2011a) is used to estimate CO_2 transport and storage costs (in $US_{2007}$$/t). Alternative biomass use options are compared with respect to five metrics. Three of these are defined and presented for the alternative options in Table 12.26: a biomass input index (BII), a greenhouse gas emissions index (GHGI), and a zero-emission fuels index (ZEFI). In addition, Figure 12.47 presents the LCOF for the six options that provide fuels,

and Figure 12.48 presents the real internal rate of return (IRRE) for four options.

BII: This index (defined in Table 12.26, note (c)) indicates that the coprocessing options (CBTL-RC-CCS and CBTL-OTA-CCS) require much less biomass to make low-C liquid fuels than the biofuel options (e.g., 36–40% as much as is required for the EtOH options).

GHGI: All options have outstanding GHG emissions mitigation performance, with GHGI less than 0.20. Four options have negative emission rates that could offset emissions from other fossil energy systems.

ZEFI: This performance index (defined in Table 12.26, note (e)) highlights the strategic importance of storing underground a large fraction of the biomass feedstock carbon not contained in the energy products, thereby exploiting the negative GHG emissions benefit of photosynthetic CO_2 storage. It quantifies simultaneously the carbon mitigation and liquid fuel insecurity mitigation potentials of an option. The higher the value of ZEFI, the better the option. Four of the options store enough photosynthetic

Table 12.26 | Alternative low carbon fuel options – each consuming 457,000 dt/yr biomass[a].

Plant name	Capacities				BII[c]	GHGI[d]	ZEFI[e]	CO₂ stored[f], Mt/y (% of feedstock C stored)	TPC[g], million US₂₀₀₇$
	Inputs		Outputs						
	Fuel, MW, HHV	% biomass, HHV basis	Electricity, MW_e	Liquid fuel, barrels/day of gasoline equivalent (MW, LHV)					
EtOH-V	302	100	2.03	1,941 (113)	2.49	0.17	0.33	0	156
EtOH-CCS	302	100	0.62	1,941 (113)	2.49	−0.21	0.49	0.11 (15)	158
BTL-RC-V	302	100	19.3	2,241 (131)	2.15	0.063	0.42	0	408
BTL-RC-CCS	302	100	14.2	2,241 (131)	2.15	−0.95	1.02	0.44 (56)	416
CBTL-RC-CCS	670	45	24.3	4,882 (284)	0.99	0.029	0.97	0.91 (54)	733
CBTL-OTA-CCS	1041	29	131	5,395 (314)	0.90	0.086	0.92	1.70 (65)	939
BIGCC-CCS[b]	320	100	118	0	–	−0.93	0.99	0.71 (90)	398

a   Based on Liu et al., 2011a. See also Box 12.3.

b   Based on unpublished modeling carried out by the authors of Liu et al., 2011a in a manner that is consistent with the modeling of the systems presented here that make liquid fuels + electricity, see Table 12.7 (in which the BIGCC-CCS case here corresponds to the switchgrass case in the PEI section of the table).

c   BII (biomass input index) ≡ Biomass energy (in GJ LHV dry) required to produce 1 GJ of liquid fuel (LHV).

d   GHGI is the system-wide life cycle GHG emissions relative to emissions from a reference system producing the same amount of power and fuels. The reference system consists of equivalent crude oil-derived liquid fuels and electricity from a stand-alone new supercritical pulverized coal power plant venting CO₂. For details, see Table 12.15, note (c).

e   ZEFI (Zero-emissions fuels index) ≡ Amount (in GJ) of equivalent zero GHG-emitting liquid fuel provided per GJ of biomass input.

f   It is assumed that captured CO₂ is compressed to 150 atmospheres, transported via pipeline 100 km to a storage site, and injected into a deep saline formation 2.5 km underground.

g   TPC (total plant cost) ≡ "overnight capital cost" (which excludes interest during construction).
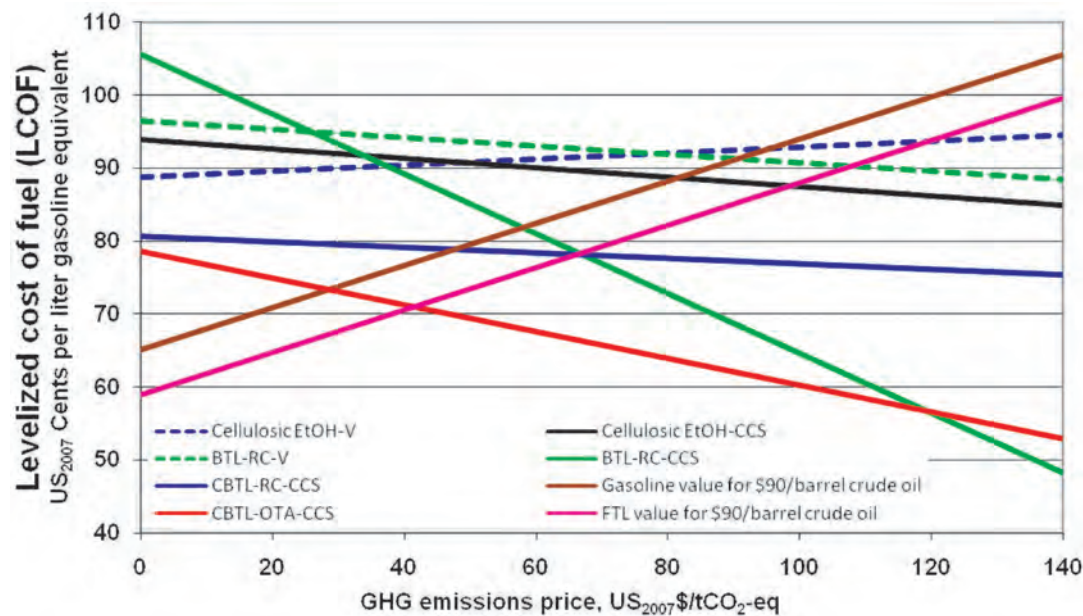

Figure 12.47 | LCOF vs GHG emissions price for the six alternative low-carbon fuel options listed in Table 12.26. Also shown are values of petroleum-derived gasoline and an average for gasoline plus diesel corresponding to the proportions of these fuels found in the FTL flues in the CBTL and BTL cases (see Table 12.15, note (a)). (See Table 12.6, note (b) for financial parameter assumptions. Also, electricity sales are assumed at the US average grid price plotted in Figure 12.10.) Based on Liu et al., 2011a.
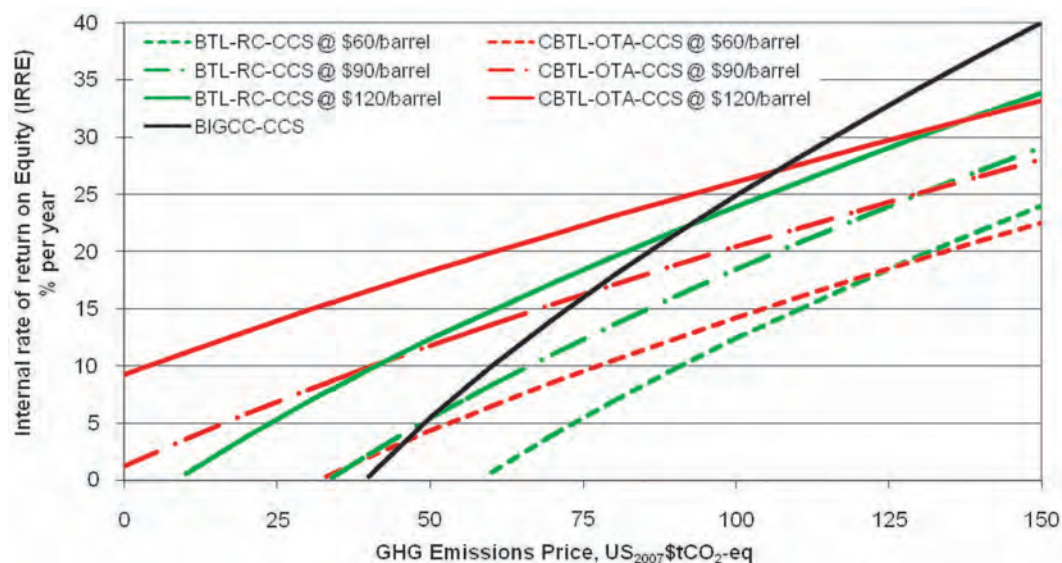
Figure 12.48 | Real internal rate of return on equity (IRRE) for BIGCC-CCS (see Table 12.26) and for the FTL options with the lowest LCOF (see Figure 12.47) for three levelized crude oil prices. Electricity sales are assumed at the US average grid price plotted in Figure 12.10. Based on Liu et al., 2011a.

CO_2 to convert (in effect) 92% or more of the biomass energy into useful zero GHG emitting transportation fuel energy. Although the BIGCC-CCS option does not provide liquid transportation fuels, the negative GHG emissions of this option enables it to offset emissions from crude oil-derived products; assuming the crude oil product displaced is gasoline, the ZEFIs for this option is high (0.99). The –V options perform poorly in terms of this metric. Notably, EtOH-CCS also has a relatively low ZEFI, reflecting the fact that only 15% of the C in the feedstock is stored underground so that the potential photosynthetic storage benefit is modest.

LCOF: Figure 12.47 shows that at all GHG emissions prices below $120/tCO_2eq CBTL-OTA-CCS offers the least costly liquid fuel, becoming competitive with the crude oil products displaced when the GHG emissions price exceeds US$40/tCO_2-eq and the crude oil price is US$90/bbl. In contrast EtOH-V requires a GHG emissions price of more than US$95/t to be competitive at this crude oil price. Notably, pursuing CCS does not markedly improve the economics of cellulosic ethanol at high GHG emissions prices – reflecting the relatively modest photosynthetic CO_2 benefit for this option (storing only 15% of the feedstock C).

Although at US$0/t, BTL-RC-CCS is the most costly transportation fuel option, its LCOF declines rapidly with GHG emissions price as a result of its strong negative GHG rate (GHGI = –0.95). This technology cannot compete with CBTL-OTA-CCS until the GHG emissions price exceeds US$120/t. However, in regions where coal coprocessing is not a realistic option, BTL-RC-CCS would become competitive with crude oil derived products for GHG emissions prices > US$67/t when the oil price is US$90/bbl. As noted earlier, *World Energy Outlook 2009* estimates that if the world community were on a path to stabilizing the atmospheric concentration of GHG gases at 450 ppmv, the world oil price would be stable during 2020–2030 at US$90/bbl, and if, in addition, there were a

single global carbon trading price, that price would be about US$70/t by 2030 (IEA, 2009b). Thus it is plausible that in the post-2030 time period BTL-RC-CCS would be cost-competitive in biomass-rich but coal-poor regions if the world community were on this carbon mitigation path.

IRRE: The real IRRE is a good metric for comparing the economics of power-only options with liquid-fuel options. Figure 12.48 shows the IRRE for the BIGCC-CCS option and the two most promising liquid fuel options analyzed here (CBTL-OTA-CCS and BTL-RC-CCS) for three crude oil prices: US$60, US$90, and US$120/bbl.[49] Several conclusions can be drawn from these curves. First, at very high GHG emissions prices, BIGCC-CCS has the highest IRRE. Second, at all three oil prices, CBTL-OTA-CCS has the highest IRRE at low GHG emission prices, and break-even with BIGCC-CCS occurs at a GHG emissions price that increases with the crude oil price: US$46/t at US$60/bbl, US$76/t at US$90/bbl, and US$107/t at US$120/bbl. Third, BTL-RC-CCS will become more profitable than CBTL-OTA-CCS at GHG emissions prices in the range US$125–130/t.

12.6.5   Coal/biomass Coprocessing with CCS as a Bridge to CCS for Biofuels

Establishing in the market over the next 20 years technologies involving coal/biomass coprocessing with CCS for the coproduction of liquid fuels and electricity could plausibly serve as a bridge to widespread biofuels production with CCS in the post-2030 time frame. This is suggested by the analyses of Sections 12.6.3 and 12.6.4 considered together. This is

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49   For these options it is assumed that the debt/equity ratio is 45/55 and that electricity is sold at the US average grid price indicated in Figure 12.10. For other financing assumptions relating to these IRRE calculations see Liu et al., 2011a.

an important consideration because biomass supplies in coal-rich countries are relatively limited but are abundant in many coal-poor regions of the world. In coal-poor regions, the economics of liquid fuel production via thermochemical conversion of biomass with CCS become economically attractive relative to crude oil-derived products at prospective GHG emissions prices for the post-2030 period if the global community were to pursue stabilization of the GHG concentration in the atmosphere at 450 ppmv. Moreover, the capital needed to build these plants should become available in a world with carbon trading and high GHG emissions prices. This is likely because not only would these plants be very competitive in providing liquid fuels, but they also would generate huge revenue streams from the sale of carbon credits.[50]

12.6.6 Global Coal/biomass Thought Experiment for Transportation

A global coal/biomass thought experiment for transportation is presented to illustrate the carbon mitigation potential for transportation by 2050 via widespread use of low-carbon fuels provided via coal and/or biomass with CCS in many regions. In coal-poor regions this would be accomplished via BTL-RC-CCS, and in coal-rich regions via CBTL-OTA-CCS. This thought experiment is set in the context of a world in which the growing of dedicated energy crops on cropland is off-limits (Tilman et al., 2009) because of concerns about impacts on food prices (Rosegrant, 2008) and land-use effects (Fargione et al., 2008; Searchinger et al., 2008).

It is assumed for the supply side of this thought experiment that the only biomass supplies are residues[51] and mixed prairie grasses grown with minimal inputs on abandoned agricultural lands. The estimated total global biomass supply under these conditions is approximately 6 Gt/yr dry biomass[52] – all of which is assumed to be used in the thought experiment. It is assumed that CBTL-OTA-CCS plants use 1 Gt/yr of biomass worldwide and that the rest of the biomass is used in BTL-RC-CCS plants located in coal-poor regions. Many of these plants would be located in developing regions such as sub-Saharan Africa and Latin America.

Dedicating the entire global biomass supply to BTL and CBTL plants is clearly an unrealistic assumption. However, as the preceding analysis has shown, these applications are likely to be hard to beat in terms of both the carbon mitigation per tonne of scarce biomass and economics in a world of high GHG emissions prices and high oil prices. Moreover, such a starkly defined global coal/biomass thought experiment helps to clarify the tradeoffs associated with the allocation of scarce biomass resources.

The demand for global transportation energy in 2050 in the thought experiment is assumed to be essentially that presented for the IEA's BLUE Map transportation scenario (IEA, 2009a), an update for the transport sector of its earlier projection to 2050 (IEA, 2008b).[53] A general characterization of the BLUE Map scenario is that it envisages technological change bringing emissions to 50% of the 2005 level by 2050. This includes a strong emphasis on improving energy efficiency but excludes lifestyle changes and modal shifts. It is appropriate to assume an energy-efficient future as a context for exploring the prospects for carbon mitigation via biomass and coal with CCS because, typically, energy efficiency improvement represents "the low-hanging fruit" in carbon mitigation (e.g., see Chapter 10) and thus should be given priority. Transportation is also one of the main branching points of different pathways considered in Chapter 17; Figure 17.2 shows possible final energy shares for transportation up to 2100 for different transportation system strategies (discussed further in Chapter 17, Section 17.3.3.4).

The challenge for global transportation is to reduce GHG emissions at midcentury by a factor of four relative to the IEA Baseline Projection in order to reduce global emissions by 50% relative to emissions in 2005. As shown in Figure 12.49, this baseline projection, which involves nearly a doubling of both energy demand and GHG emissions relative to 2005, illustrates the dimensions of this challenge.

In our global coal/biomass thought experiment, while transportation demand in 2050 is essentially that in the BLUE Map scenario, we modify that scenario by excluding some technologies. We are working from the assumption that no plug-in hybrid vehicles, no all-electric vehicles, and no H_2 fuel cell vehicles are included in the light-duty vehicle (LDV) mix in the period to 2050. This is in contrast to the actual BLUE Map scenario, which assumes a high penetration of these technologies in the mix by midcentury.[54] Obviously, this exclusion is not a realistic assumption, because these technologies are being heavily promoted by governments. The main reason for the exclusion is to bring to the attention of policymakers that, as shown in this chapter, deep reductions can be plausibly realized (e.g., via pursuit of CCS for coal and biomass) at attractive production costs with essentially no costly changes in transportation fuel infrastructures and with evolutionary rather than revolutionary changes

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50 For example, at a GHG emissions trading price of $70/tCO$_2$-eq, the present worth of the stream of revenues (over the assumed 20-year economic life of the plant) from the sale of carbon emissions credits for the BTL-RC-CCS plant described in Table 12.26 would be equivalent to 73% of the TPC for the plant.

51 Agricultural residues, forest residues, forest thinnings to reduce forest fire risk and enhance productivity for commercial species, urban wood wastes, municipal solid wastes.

52 In energy terms, the residue supply is assumed for 2050 to be 75 EJ/yr (the global residue supply for energy assumed for 2050 in IEA, 2008b). The assumed potential supply of biomass grown on abandoned agricultural lands is 32 EJ per year (average yield of 4.3 dry tonnes/yr on 429 million hectares worldwide) based on Campbell et al. (2008). The total biomass supply, 107 EJ/yr, is 2.3 times total biomass use for energy in 2005. For comparison, the global biomass supply for 2050 in the IEA Blue Map scenario is 150 EJ/yr (which includes biomass grown for energy on cropland), and the maximum biomass resource availability for 2050 is estimated in Chapter 7 to be still higher than this. For perspective, the total assumed global biomass supply (107 EJ/yr) is comparable to total US primary energy use in 2006 (97 EJ/yr).

53 For the IEA Baseline Projection the total number of light-duty vehicles (LDVs) increases three times to 2.15 billion, 2005–2050, air travel increases 3.9 times, and truck freight increases 1.9 times.

54 In 2050 the LDV fleet in the IEA BLUE Map Scenario (IEA, 2009a) includes 37% plug-in hybrids, 21% all-electric vehicles, and 25% H_2 hybrid fuel cell vehicles.
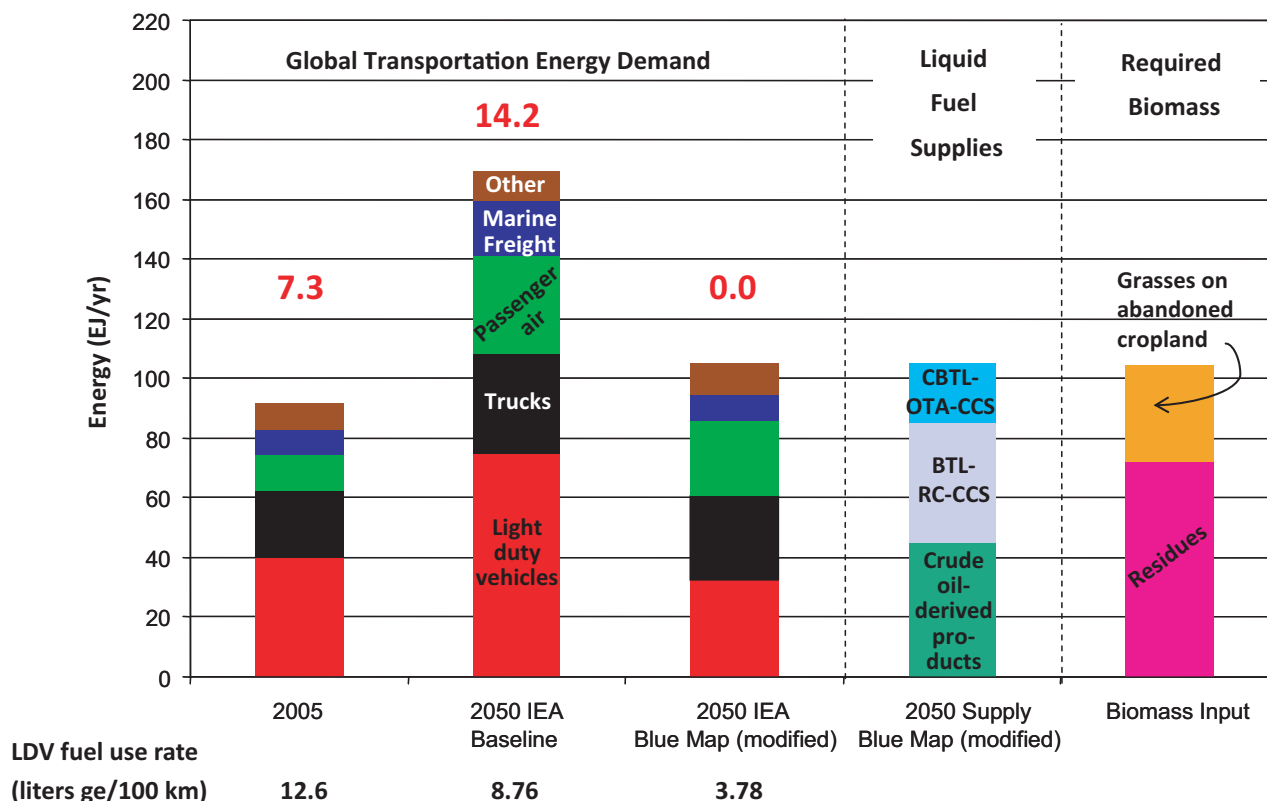
Figure 12.49 | Energy and GHG emissions for global coal/biomass thought experiment and for IEA 2050 Baseline (business-as-usual) scenario. Numbers at tops of bars are total GHG emissions in GtCO$_2$-eq/yr. LDV fuel use rate is in liters of gasoline equivalent per 100 km. Source: see discussion in text.

in automotive engine technologies. In particular, energy-efficient LDVs[55] (e.g., advanced gasoline and diesel hybrid electric vehicles) are emphasized in our modified BLUE Map scenario. Our hope is that this modified scenario will inspire policymakers to take a more balanced approach toward decarbonizing the transportation sector and to create policies that enable the low carbon transportation technology options that have been the focus of this chapter to compete alongside the technologies that are intensely promoted in current policies.

The resulting liquid fuel demand and supply for global transportation under the modified BLUE Map scenario are shown as the 3rd and 4th bars of Figure 12.49. Total net GHG emissions are zero for global transportation in 2050 under the conditions of the global coal/biomass thought experiment. The liquid fuel supply would be made up of 19% FTL via CBTL-OTA-CCS, 38% FTL via BTL-RC-CCS, and 43% crude oil–derived products. The level of crude oil-derived products used in transportation

is 51% of the amount of crude oil derived products used for transportation worldwide in 2005. The projected GHG emissions are zero despite the large share of crude oil-derived products in the mix because it is assumed for the thought experiment that the negative emissions from BTL-RC-CCS systems are used to offset positive GHG emissions from both crude oil-derived products and CBTL-OTA-CCS systems.

In 2050 coal use for the modified BLUE Map scenario (with the global coal/biomass thought experiment) is 1.15 times global coal use in 2005, compared to 0.78 times for the IEA BLUE Map scenario and 3.04 times for the IEA Baseline Scenario.

Under the conditions of the thought experiment, CO$_2$ storage would be carried out in 2050 at rates of 3.7 Gt/yr for CBTL-OTA-CCS plants and 4.8 Gt/yr for BTL-RC-CCS plants. This finding highlights the importance of ascertaining the extent to which there are good geological CO$_2$ storage opportunities in biomass-rich but coal-poor regions, where consideration of CCS as a carbon mitigation option has probably not been given much thought.

Is it plausible that about ten thousand BTL-RC-CCS plants[56] might be up and running by 2050 (each processing 0.5 Mt of biomass annually)? If one imagines starting with 20 such plants by 2030 the annual average

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55   In the IEA (2009a) scenarios, average fuel economies for new LDVs in 2050 are 5.9 liters of gasoline equivalent per 100 km (l$_{ge}$/100 km) or 40 miles per gallon of gasoline equivalent (mpg$_{ge}$) for the Baseline Scenario and 2.9 l$_{ge}$/100 km (81 mpg$_{ge}$) for the BLUE Map scenario. The average fuel economy assumed for the entire LDV stock in 2050 in the modified BLUE Map scenario is 2.9 l$_{ge}$/100 km (62 mpg$_{ge}$), which is consistent with the IEA assumptions for the average fuel economy for new LDVs in the actual BLUE Map scenario. There are reasonable prospects that this average fuel economy for the LDV stock could be realized without use of plug-in hybrids or fuel cell vehicles. Kromer and Heywood (2007) have estimated that by 2030 a mid-sized conventional hybrid-electric car (essentially a 2030 version of a Prius) could have a fuel economy of 3.1 l$_{ge}$/100 km (76 mpg$_{ge}$).

56   Each of which provides 2,200 bbl/day of gasoline equivalent FTL + 14 MW$_e$ of electricity and requires an investment of US$420 million (see Table 12.26).

growth rate in plant deployment, 2030–2050, would have to be 37%/yr. This extraordinarily high growth rate would not take place without supportive public policy, but it is not inconceivable. In its heyday, nuclear power grew worldwide at a sustained average growth rate of 37%/yr from 1957–1977.

Much of this growth would take place in now-impoverished developing countries, where this technology would represent a major opportunity for industrial growth. But many such countries currently have neither the needed physical infrastructures (e.g., roads, railroads, pipelines, port facilities for managing exports, etc.) nor the human capacity to manage such industrial growth. The technology is not likely to be cost competitive until about 2030 even under strong carbon-mitigation policies worldwide, however, so there is a strategic opportunity to build those needed capacities in the interim – if the global community comes to think that there is a pressing need for this industry.

Finally, if the goal for decarbonizing global transportation were to reduce by 2050 GHG emissions for transportation worldwide not to zero but rather to half the 2005 level (in line with current long-term policy goals for carbon mitigation), the global biomass requirements for 2050 drop to a level that is only 38% higher than global biomass use in 2005 – so that considerable biomass would be available for purposes other than to satisfy the global coal/biomass thought experiment needs. Moreover, crude oil-derived products (in an amount equivalent to 69% of the level for transportation in 2005) would account for 60% of total transportation energy in 2050.

12.7   Long-term Considerations

The preceding analyses in Chapter 12 focused mainly on technologies that are near at hand. It is beyond the scope of Chapter 12 to present a comprehensive review of advanced fossil energy conversion technologies. Rather, the focus in this short section is on some advanced technologies that might be especially helpful in evolving to promising longer-term future low-GHG emitting fossil-fuel-based electricity and synfuels technologies and strategies.

12.7.1   Low-carbon Electricity Generation Technologies in the Long-term

For systems that provide only electricity, a brief review is presented of prospects for substantial cost reduction in systems with CCS. The review is restricted to gasification-based systems for three reasons. First, with current bituminous coal technologies, CIGCC systems with pre-combustion CO_2 capture outperform PC systems with post-combustion capture – as shown in Section 12.2.3. Second, synfuel/electricity coproduction systems that require gasification have astonishingly good economic prospects even with current technologies, as discussed in Section 12.6.3. Reason number three has to do with the fact that coal gasification technologies are at a much earlier stage in their technological evolution than

are coal combustion technologies. Over the longer term, it is plausible that conversion efficiencies will be higher and costs for generating coal electricity with CCS will be lower with advanced gasification technologies than the costs presented in detail in earlier sections of Chapter 12.

A recent report from the US National Energy Technology Laboratory gives a sense of the possibilities: Gray et al. (2009) describe two alternative technological paths for gasification energy to provide power from coal with CCS: (i) an evolutionary change path that involves a series of incremental changes in CIGCC technology and (ii) a revolutionary change path that involves a shift from combustion energy conversion to electrochemical energy conversion via use of solid oxide fuel cells (SOFCs). Here key findings of Gray et al. (2009) are sketched out to highlight the importance of a major research and development effort in this area.

The evolutionary change approach for CIGCC involves the following incremental changes over time:

- a continuation of the historical trend toward improved gas turbine performance as a result of increasing firing temperatures and higher pressure ratios, but with emphasis in a carbon-constrained world on gas turbines burning hydrogen;

- introduction of a dry coal feed pump to reduce the energy penalty associated with evaporating water via a coal/water slurry feed system and to provide a simplified alternative to the lockhopper dry feed systems currently used;

- warm acid gas removal with CO_2 capture in Selexol instead of the current cold CO_2 capture in Selexol, to greatly reduce the energy penalty otherwise required for Selexol regeneration;

- warm acid gas removal with H_2 and CO_2 separation via a hydrogen separating membrane that delivers hydrogen in a pressurized N_2/H_2 mixture to the gas turbine combustor while enabling CO_2 recovery as a separate stream at elevated pressure, thereby reducing the CO_2 compressor load;

- use of an ion transport membrane[57] instead of a cryogenic air separation unit to provide O_2 for the gasifier – the main impact of which would be to reduce the capital cost for O_2 production;

- increased system reliability, availability, and maintainability – resulting in an increased system capacity factor.

Gray et al. (2009) carry out a systems analysis suggesting that success in all of these areas over time could plausibly lead, for US conditions, to

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57 A non-porous ceramic membrane through which O_2 ions flow at high temperature (800–900°C) and are converted to O_2 molecules on the permeate side of the membrane, while electrons flow countercurrent to the retentate side of the membrane.

an eventual IGCC-CCS efficiency ~40% (HHV basis) and a capital cost (TPC) less than US$1700/kW$_e$ – values very similar to the corresponding values for new supercritical steam-electric plants in the US today (the PC-V option described in Section 12.2.2).

The revolutionary SOFC approach involves coupling a high-efficiency SOFC operating at pressure to a catalytic gasifier that produces methane-rich syngas, such as the gasifier being developed by Great Point Energy (a company in the United States) for making substitute natural gas.[58] As the syngas passes through the anode of the SOFC the methane is reformed with steam to form CO and H$_2$, and these gases in turn react with steam and oxygen to form CO$_2$ and H$_2$O while providing electric power for the external circuit. Part of the heat released in these reactions is manifest as a rise in the syngas temperature from 600°C to 900°C as it passes through the anode. The oxygen is provided as O$_2^-$ ions (undiluted with nitrogen) via transport through the fuel cell's non-porous ceramic membrane electrolyte[59] from the hot air streaming through the cathode. The benefits of this approach to power generation (Grol et al., 2007) include the following:

- Making electricity directly from chemical energy without first having to burn the fuel to make heat gives rise to higher energy conversion efficiency than can be realized via fuel-powered heat engines.

- The lower gasification temperature of the catalytic gasifier means that less energy is needed to heat the gas to its operating temperature, so that the gasification efficiency is higher.

- Another benefit is energy and cost savings, given the fact that with a sufficiently high fraction of methane in the gasifier-generated syngas, the methanation reaction exotherm can provide enough heat for gasification – which implies significant energy and cost savings associated with air separation that would otherwise be needed to provide oxygen for gasification.

- The SOFC produces steam when H$_2$ in the syngas and pure O$_2$ react on the anode; the steam reacts with methane in the syngas producing CO and H$_2$; the CO reacts with more steam to produce H$_2$ and CO$_2$, so that what ultimately leaves the system is a stream of CO$_2$ and H$_2$O – from which CO$_2$ is easily separated for piping to an underground storage reservoir.

- The strong endotherm of the methane steam reforming reaction on the anode absorbs a considerable amount of heat released from the oxidation of H$_2$ to produce water, thereby reducing the amount

of air required to cool the SOFC – one manifestation of which is a reduction of the amount of air compression that would otherwise be required to provide this cooling air.

- If the SOFC operates at an elevated pressure, the subsequent CO$_2$ compression required for pipeline transport to suitable storage sites would be less than if the SOFC operates at atmospheric pressure.

- The steam reforming of methane on the anode eliminates the need for a separate steam reformer when methane-rich syngas is the feed.

- The "shifting" of CO to CO$_2$ by reaction on the anode with water, producing H$_2$, eliminates the need to shift CO to CO$_2$ in a separate "water-gas-shift" reactor.

Gray et al. (2009) have estimated prospective efficiency, capital cost, and levelized electricity production costs for such SOFCs and compared them to the same quantities that would arise with the evolutionary strategy. They found that the system efficiency would be 40% higher (~56%), the specific capital cost (US$/kW$_e$) would be ~5% higher and the levelized cost of electricity would be about the same – although perhaps requiring a longer period of time to achieve such estimated performance and cost values. Many of the technological advances analyzed would be applicable to systems that coproduce synthetic fuels and electricity, as described for current technologies in Section 12.6. These findings suggest that both the evolutionary and the revolutionary approaches warrant comparable levels of research and development support. It does not necessarily follow, however, that these two approaches would offer comparable overall benefits when the technologies involved are fully developed.

12.7.2 Technologies and Strategies for Low-carbon Liquid Fuels in the Long-term

Maintaining the option of sustaining liquid hydrocarbon fuels as the primary energy carriers for the transportation sector even under a severe carbon policy constraint is extraordinarily important in light of the ease of transporting, storing, and using these fuels compared to the alternatives such as H$_2$ and electricity (e.g., see near the end of Section 12.4.4 for some discussion of the challenges for evolving a ground transportation system based on hydrogen fuel cell vehicles).

In the earlier Chapter 12 analysis of opportunities for producing synthetic fuels characterized by low greenhouse gas emission rates, some of the most important findings were the strategic importance of:

- CCS for biomass as a carbon mitigation strategy for a carbon-constrained world;

- the opportunity to get started with CCS for biomass via coal/biomass coprocessing; and

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58 Based on the original Exxon process, Great Point Energy's catalytic gasifier is a relatively low-temperature gasifier that involves the production of methane as a considerable fraction of the syngas output as a result of a potassium-catalyzed methanation reactions.

59 The SOFC electrolyte permits the flow of O$_2$ ions (like the ceramic non-porous ion transport membrane mentioned above for O$_2$ production) but does not permit electrons to flow in the reverse direction.

- electricity + synfuels coproduction w/CCS as a critical path for coprocessing in realizing simultaneously:

  - Low costs for low-C electricity;

  - Low costs for low-C synfuels;

  - Energy insecurity mitigation in a manner consistent with realization of carbon-mitigation objectives.

Chapter 12 points out that first generation technologies based on these novel concepts can be deployed in the market during the current decade. Much can be done to improve such systems using advanced technologies. Although a systematic review of advanced concepts is beyond the scope of the present analysis, what is discussed here is of possible strategic importance:

- a new approach to chemical synthesis in the context of a carbon constrained world;

- shale gas for a carbon-constrained world; and

- extension of the coproduction concept from the present focus on coal/biomass coprocessing to include as well natural gas/biomass coprocessing.

12.7.2.1   Synthesis chemistry for a carbon-constrained world

The chemical process industry and the embryonic synfuels industry are based on making synthesis gas (mainly CO and H_2) from a fossil fuel and/or biomass and then combining the synthesis gas molecules CO and H_2 to make chemicals and/or fuels. A recent paper (Hildebrandt et al., 2009a) points out that there are potentially significant gains in energy conversion efficiency to be exploited by shifting both the gasification process from the production of mainly CO and H_2 to the production of instead mainly H_2 and CO_2 and basing the subsequent chemical synthesis on combining H_2 and CO_2 instead of H_2 and CO. Applying the idea to the production of F-T liquids from coal via gasification, those authors point to an 18% theoretical potential reduction in the amount of net work required for the overall process and a 15% reduction in the amount of coproduct CO_2 generated in the process.[60]

This idea might be helpful in the context of a carbon mitigation policy, for evolving from the present situation where energy is based mainly on fossil fuels, to an energy future in the very long term when synthetic liquid hydrocarbon fuels might be made mainly by combining H_2 derived from water using a non-carbon primary energy source[61] such as solar energy or thermonuclear fusion, and CO_2 extracted directly from the air[62] to make liquid fuels – a process that might start with methanol production:

$$CO_2 + 3\ H_2 \rightarrow CH_3OH + H_2O, \qquad (6)$$
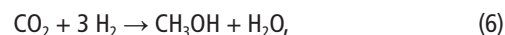
followed by conversion of the methanol to hydrocarbon liquid fuels such as gasoline via the already commercial MTG processes (see Sections 12.4.1.2 and 12.4.3.1) or via future processes that would produce middle distillates as well as gasoline (Keil, 1999).

Though seemingly different in the case of methanol production from the present approach that involves making methanol from syngas via:

$$CO + 2H_2 \rightarrow CH_3OH, \qquad (7)$$

it is now well known (Hansen, 1997) that what really happens in making methanol from syngas is that CO first reacts with H_2O to form CO_2 and H_2 via the water gas shift reaction followed by the hydrogenation of CO_2 on the catalyst surface. Moreover, making methanol from CO_2 and H_2 is actually not a novel approach.[63]

At present H_2 produced from non-carbon energy sources is far more costly than making H_2 with ultra-low GHG emissions from coal or natural gas with CCS (Williams, 2002), and direct extraction of CO_2 from the air is far from being economic.[64] Nevertheless, the concept of making chemicals and synfuels from $CO_2 + H_2$ could potentially be of strategic importance even in the near term in fossil fuel and fossil/biomass systems that make synfuels (or synfuels + electricity) and produce CO_2 as a major coproduct. Under a serious carbon policy constraint, the excess CO_2 has to be captured and stored underground in any case; a key insight implicit in the Hildebrandt analysis (Hildebrandt et al., 2009a; Hildebrandt et al., 2009b) is that there may be strategic advantages of using this readily available CO_2 to improve overall energy system performance before delivering the excess to underground storage.

This discussion ends with a word of caution. The importance of potentially improving system efficiencies by exploring gasification and synthesis

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60 An e-letter comment on the Hildebrandt et al. (2009a) paper by Desmond and Gibson (2009) points out that at the high gasification temperature considered it is not practical to design a gasifier that produces mainly H_2 and CO_2 unless an enormous amount of water is added to promote the water-gas-shift reaction, but the energy penalty of heating that water would eliminate potential energy savings. Hildebrandt et al. (2009b) responded that it would be practical to produce mainly H_2 and CO_2 if one considers not a single piece of equipment but rather a gasifier followed by a water-gas-shift reactor operated at a much lower temperature than the gasifier. But if that were done it is not clear how one could realize energy savings for the gasification part of the system, although there would still be significant savings by basing synthesis on $CO_2 + H_2$. Moreover, the GHG emissions associated with the water heating referred to in the Desmond and Gibson (2009) criticism could be mitigated by heating the water with solar energy instead of burning fossil fuel.

61 See, for example, Lewis and Nocera (2006) and OSL (2003).

62 See, for example, Section 2.1.4: Carbon dioxide capture from ambient air, in The Royal Society (2009).

63 Olah et al. (2009) point out that the very first methanol plants operating in the 1920s and 1930s were commonly using CO_2 and H_2 from other processes to make methanol.

64 In a recent report of the American Physical Society, it is estimated that with current technology direct air capture of CO_2 would cost $600 or more per tonne of CO_2, under optimistic assumptions (APS, 2011).

based on CO_2 chemistry should not be construed as suggesting that CO_2 reuse to make synthetic fuels is a viable alternative to CCS.

There is widespread interest in CO_2 reuse for making industrial products as an alternative to CCS. For example, the US Department of Energy has dedicated more than US$107 million to the exploration of twelve approaches to reuse (DOE, 2010). Of these concepts, the most numerous and globally significant are systems that use microalgae to capture CO_2 from power plant flue gas and convert it (via sunlight, water, and nutrients) into natural oils that are readily processed into liquid transportation fuels such as biodiesel. The concept is tantalizing when one considers, as an example, that the United States in 2008 consumed fossil fuel carbon in the amounts of 500 Mt in the form of transportation fuels while simultaneously emitting 540 Mt from pulverized coal steam electric power plants. If the CO_2 in flue gases were captured and reused by being converted into carbonaceous liquid fuels using solar energy or another non-carbon energy source to provide the needed process energy, enormous quantities of transportation fuels could be provided without increasing GHG emissions. But this example contains the essence of the shortcomings of reuse to make transportation fuels: If, hypothetically, 100% of the CO_2 from flue gases of US coal power plants were converted via carbon-free energy sources into transportation fuels, the carbon emissions for the system of making both transportation fuels and electricity from coal would be reduced by only 50% from the level of the current system that makes electricity from coal with CO_2 venting and transportation fuels from crude oil.

Kreutz (2011) examines two cases to estimate the potential for GHG emissions reduction via reuse of coal power plant CO_2 to make liquid transportation fuels: the growing of algae in algal ponds to make biodiesel and the use of concentrated sunlight to reduce CO_2 to CO and O_2 and/or H_2O to H_2 and O_2 to make liquid fuels via Fischer-Tropsch synthesis. He shows that the carbon mitigation potential of reuse strategies to make synthetic transportation fuels is at best very modest in a world where the carbon price is high enough to induce decarbonization of coal power plants either by shifting to a carbon-free or low-carbon power source or by making CCS more economical than venting CO_2 (in which case the CO_2 would be captured and available mainly in pipelines to underground storage sites so that its diversion from this purpose would be equivalent to extracting CO_2 from underground).[65] According to Kreutz: "Using the carbon twice fails to meet the objective of deep GHG emission reductions across the entire energy economy; only one sector (either power or transportation) – but not both – can claim the benefit of carbon neutrality." Thus CO_2 reuse strategies to make synthetic fuels would not enable the deep (over 80%) reductions in GHG emissions that leaders of industrialized countries are targeting for their countries by midcentury.

12.7.2.2   Implications of Abundant and Ubiquitous Shale Gas

It is truly remarkable how fast views of the fossil fuel energy future change. In its 2003 report to the US Secretary of Energy, the National Petroleum Council (NPC, 2003) predicted that future North American natural gas supplies would be flat or declining. In sharp contrast, there is currently much bullishness about the future prospects of shale gas, largely as a result of applications of new effective, economic hydraulic fracturing and horizontal drilling technologies.[66] It is now thought that natural gas extracted from shale in sedimentary basins might turn out to be abundant and ubiquitous, with reasonable production costs. Although most empirical data are from the United States, there is much optimism that the judgments that are now being formed about US shale gas prospects might be more or less valid for sedimentary basins throughout the world (see Chapter 7).

If this bullishness about shale gas proves to be sound, and growing environmental concerns associated with extraction of shale gas (Rahm, 2011) can be addressed, it has potentially far-reaching implications for the future of fossil fuel energy in a carbon-constrained world.

To begin, CCS would need to be pursued for NG energy conversion systems based on shale gas in order to meet carbon mitigation obligations over the longer term. Consider first use of shale gas for making electricity in NGCC-CCS plants. One advantage offered relative to CIGCC-CCS plants is that less than half as much CO_2 would have to be stored per MWh. Moreover, the capital investment required to generate electricity via NGCC-CCS is likely to be less than half that for a CIGCC-CCS plant having the same output capacity, and the LCOE for such a plant is likely to be less than for a CIGCC-CCS plant at the GHG emissions price needed to make a CIGCC-CCS plant cost competitive with a PC-V plant for natural gas prices up to four times the coal price.[67] The downside for the NGCC-CCS system is that the GHG emissions price required to induce a shift from NGCC-V to NGCC-CCS is very high (see Figure 12.10).

12.7.2.3   Gas/biomass to Liquids and Electricity with CCS

Should shale gas prove to be as abundant and ubiquitous as some believe, it will be of interest to consider the merits of using shale gas for liquid fuels production. The high breakeven GHG emissions price required to induce CCS for gas-based power generation could be greatly reduced while simultaneously making it possible to realize deep reductions in GHG emissions for synthetic liquid fuels if natural gas were coprocessed

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65   This is in contrast to the case at low carbon prices, when using CO_2 from flue gases is equivalent to extracting CO_2 from the atmosphere, because a profit-motivated power generator would rather vent the CO_2 to the atmosphere and pay the emissions fine than invest in CCS.

66   There are fundamental differences in the production of gas from shale and from other unconventional sources such as tight sands (Frantz Jr. and Jochen, 2005). The latter yield a tremendous amount of gas for the first few months, but then production declines significantly and often becomes uneconomic after a relatively short time. In contrast, shale gas wells do not come on as strong as gas from tight sands but, once production stabilizes, the wells will produce consistently for 30 years or more.

67   For a coal price of US$2.0/GJ.

with biomass to make liquid fuels + electricity with CCS – analogous to the CBTL-OT-CCS and CBTL-OTA-CCS systems discussed in Section 12.6.

Liu et al. (2011b) present analysis of systems coproducing FTL and electricity from natural gas and from natural gas + biomass (switchgrass). Two of the systems analyzed are described in Table 12.27. The GBTL-OT-CCS option (see Figure 12.50), which provides 300 MW$_e$ of net electricity + 9750 bbl/day of FTL transportation fuels, was designed to coprocess enough biomass (34%) to reduce GHGI to 0.10. The output capacities of the system were determined by the design criterion that the system consumes 1 Mt/year dry biomass. Its system features are compared to the same system without CCS (GBTL-OT-V) and two coal based systems that also coprocess 1 Mt of biomass annually: CBTL-OTA-CCS, which coprocesses 29% biomass to realize GHGI = 0.0855 (discussed in Section 12.6.3.3 (see Figure 12.31)), and a variant without CCS.

Notable differences between the natural gas-based and coal-based coproduction systems can be gleaned from Table 12.27:

- The natural gas-based systems convert 34.5% of the feedstock C to FTL compared to 24.2% for the coal-based systems – a consequence of the much lower H/C ratio for coal compared to natural gas (0.8 vs 4.0);

- The FTL output amounts to 34.4% of input energy for natural gas-based systems compared to 32.5% for coal-based systems, showing that the low rate of carbon conversion in the coal case is largely compensated for by the water gas shift reaction, which entails a relatively minor energy penalty;

- The CO_2 storage rate for GBTL-OT-CCS is only half that for CBTL-OTA-CCS, reflecting both the lower H/C ratio for coal and the fact that the latter option vents as CO_2 only 6.6% of the C in the feedstock compared to 12.4% in the GBTL-OT-CCS; and

- The GBTL-OT-CCS option is much less capital intensive than the CBTL-OTA-CCS option.

Figure 12.51 presents the levelized cost of electricity (LCOE) vs GHG emissions price for these four options along with the LCOEs for four stand-alone power plants (discussed in Section 12.2.2), assuming for all cases that: (i) the levelized fuel prices are US$2.04/GJ$_{HHV}$, US$5.1/GJ$_{HHV}$, and US$5.0/GJ$_{HHV}$ for coal, natural gas, and biomass, respectively (see note (b) of Table 12.6 for additional financial parameter assumptions), (ii) a US$90/bbl crude oil price, and (iii) the captured CO_2 that is pressurized to 150 atmospheres is transported via pipeline 100 km and stored in a deep saline formation 2 km below ground with a maximum injectivity per well of 2500 t/day. The important results from this set of curves are:

- Compared to other stand-alone power plants, the GBTL-OT-CCS option has outstanding performance under a carbon policy constraint,

having breakeven GHG emission prices of: US$25/t in competing with sup PC-V, US$28/t in competing with NGCC-CCS, and US$47/t in competing with NGCC-V; moreover, GBTL-OT-CCS would be able to compete with CIGCC-CCS even at $0/t. For comparison the breakeven GHG emissions price for NGCC-CCS competing with NGCC-V is about US$83/t.

- At the assumed reference feedstock prices GBTL-OT-CCS is not competitive with CBTL-OTA-CCS.

- However, the relative competitiveness between the natural gas-based and coal-based coproduction systems depends sensitively on the relative coal and natural gas prices. For example, at a GHG emissions price of US$0/t the LCOEs for these two coproduction options with CCS would be equal with a modest decrease of 8% in the assumed natural gas price (to US$4.7/GJ$_{HHV}$) and a modest increase of 8% in the assumed coal price (to US$2.19/GJ$_{HHV}$).

Finally, a global gas/biomass thought experiment for transportation is constructed in the same spirit as the global coal/biomass thought experiment for transportation presented in Section 12.6.6 to illustrate how zero net GHG emissions for transportation in 2050 might be realized via widespread deployment of a combination of GBTL-OT-CCS + BTL-RC-CCS systems instead of CBTL-OTA-CCS + BTL-RC-CCS systems, assuming the same demand levels as in the global coal/biomass thought experiment presented in Figure 12.49.

A comparison of some attributes of the two global thought experiments is presented in Table 12.28. This table shows that overall production rates for FTL fuels, the amounts of crude oil products used, the total GHG emissions avoided in displacing conventional fossil fuels, and electricity generation rates are comparable for the two thought experiments. The amount of coal used in the coal/biomass thought experiment (which produces a larger fraction of FTL via coproduction) is 25% more than the amount of gas used in the gas/biomass thought experiment. The amount of CO_2 storage required with natural gas is only 80% of that for coal, reflecting in large part the lower carbon content of natural gas compared to coal.

The relative roles of coal-based and natural-gas based systems will vary from region to region depending on relative coal and natural gas prices. Despite the bullishness about shale gas in the United States, total US domestic gas supplies are not likely to be adequate to support a substantial role for GBTL-OT-CCS. This conclusion is suggested by the analysis in Section 12.6.3.4. However, the finding presented in Table 12.28 that total worldwide natural gas use in the modified BLUE Map scenario (which includes the natural gas used for the global gas/biomass thought experiment) is only 0.81 times the projected worldwide natural gas use in the IEA Baseline Scenario – suggests that at the global level gas supplies might be adequate for realization of the global gas/biomass thought experiment. In any case, the potential benefits of the gas/biomass coproduction option as indicated in

Table 12.27 | Performance and capital cost (US$_{2007}$) estimates for coproduction systems with biomass/fossil fuel coprocessing.

	CBTL-OT-V	CBTL-OTA-CCS	GBTL-OT-V	GBTL-OT-CCS
Input capacities				
Coal, as-received mt/day (MW$_{HHV}$)	5150 (1616)	5150 (1616)		
Natural gas, mt/day (MW$_{HHV}$)			2084 (1278)	2084 (1278)
Biomass, as-received mt/day (MW$_{HHV}$)	3581(660.5)	3581(660.5)	3581(660.5)	3581(660.5)
Biomass % of total input, HHV basis	29.0%	29.0%	34.1%	34.1%
Output capacities				
Synthetic diesel + gasoline, MW LHV (bbl/d crude oil products displaced)	687 (10,882)	687 (10,882)	619 (9,752)	619 (9,752)
Diesel fraction of FTL (LHV basis)	0.634	0.634	0.669	0.669
Gasoline fraction of FTL (LHV basis)	0.366	0.366	0.331	0.331
Gross electricity production, MW	521.1	465.9	484.0	430.5
Net electricity exports, MW	407.8	287.4	384.5	300.2
FTL/Electricity output ratio	1.69	2.39	1.61	2.06
ENERGY RATIOS (HHV basis)				
Liquid fuels out /Energy in	32.5%	32.5%	34.4%	34.4%
Net electricity/Energy in	17.9%	12.6%	19.8%	15.5%
Fuels + electricity/Energy in	50.4%	45.1%	54.2%	49.9%
C input as feedstock, kgC/sec	54.5	54.5	34.4	34.4
C stored as CO$_2$, % of feedstock C	0	65.5	0	51.7
C in unburned char, % of feedstock C	3.7	3.7	1.4	1.4
C vented, % of feedstock C	45.0	6.6	64.0	12.4
C in FTL, % of feedstock C	24.2	24.2	34.5	34.5
C stored, MtCO$_2$/yr[a]	0	3.71	0.0	1.85
GHGI[b]	0.903	0.0855	0.539	0.105
Plant capital costs, million US$_{2007}$$				
Air separation unit + O$_2$/N$_2$ compressors	243	255	217	216
Biomass handling and gasification	335	335	295	295
Coal handling and gasification	396	396	-	-
Syngas cleanup	180	215	153	197
NG handling	-	-	4.0	4.0
CO$_2$ compression	1.6	33	0	21
F-T synthesis & refining	208	208	204	203
Naphtha upgrading	35	35	31	31
Autothermal reformer	0	55	87	87
Power island gas turbine	98	86	92	94
Heat recovery and steam cycle	224	168	154	166
Total plant cost (TPC), million US$_{2007}$$	1,720	1,786	1,236	1,313
Specific capital cost, US$_{2007}$$/kW$_e$	4,218	6,215	3,213	4,375

a With plant operating at 90% capacity factor.

b GHGI is the system-wide life cycle GHG emissions relative to emissions from a reference system producing the same amount of power and fuels. The reference system consists of electricity from a stand-alone new supercritical pulverized coal power plant venting CO$_2$ plus equivalent crude oil-derived liquid fuels. See Table 12.15, note (c), for details.

Table 12.28 suggest the importance of exploring further gas/biomass coproduction systems – which might offer a key to exploiting abundant and ubiquitous shale gas in a carbon-friendly manner. However, environmental concerns about "fracking" technologies used for shale gas recovery with respect to protection of water (Osborn et al., 2011) and soil (Jones, 2011), as well as concerns about life cycle GHG balances for shale gas (Howarth et al., 2011), need to be addressed effectively.
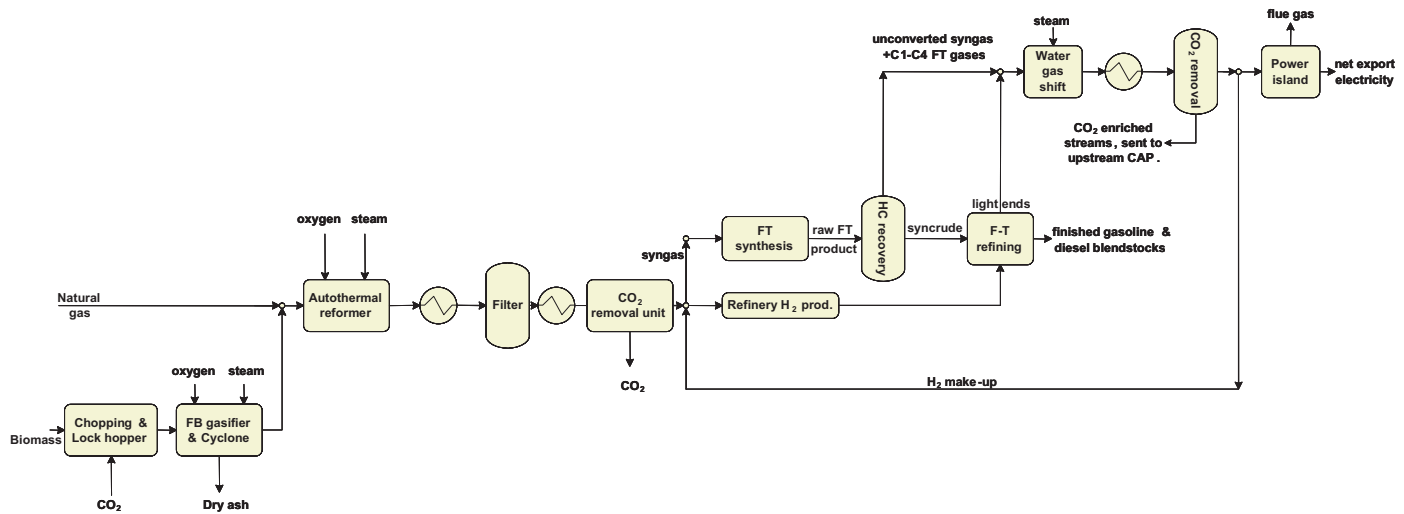
Figure 12.50 | GBTL-OT-CCS system that provides electricity + FTL (via use of a cobalt catalyst) from natural gas and biomass. Natural gas is converted to syngas in an autothermal reformer. Syngas is generated from biomass in a fluidized bed gasifier. The autothermal reformer is also used to crack (i.e., eliminate) the tars from the biomass-derived syngas. 52% of C in the feedstocks is captured, compressed to 150 bar, and sent via pipeline to a geological storage site. The system was designed with enough biomass coprocessing (34%) to realize GHGI = 0.10. Source: based on Liu et al., 2011b.
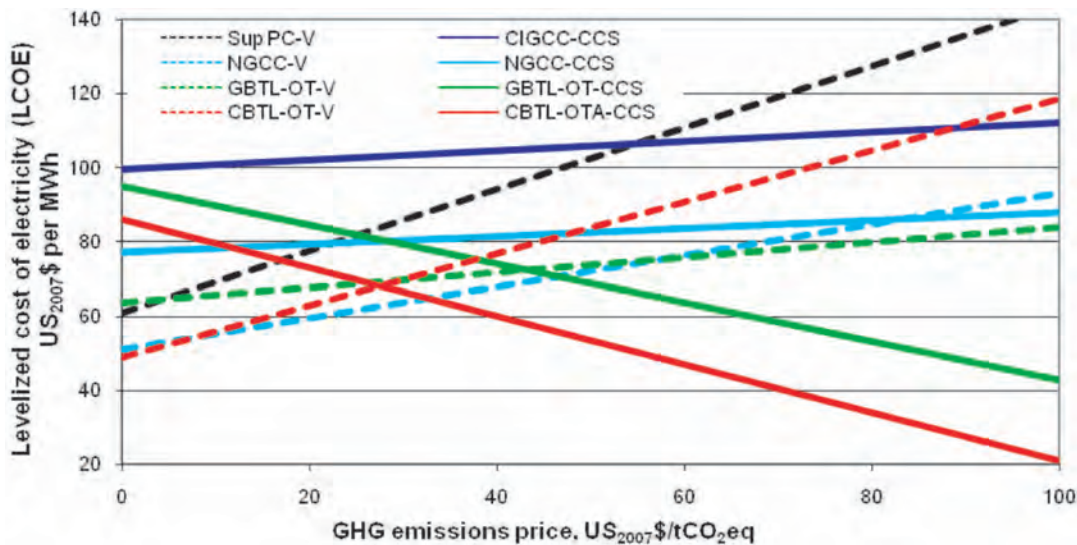

Figure 12.51 | Levelized cost of electricity vs GHG emissions price for the coproduction technologies in Table 12.27 and stand-alone power options – assuming a US$90/bbl of crude oil price and reference case coal and natural gas pricing (US$2.04/GJ and US$5.1/GJ, respectively). (See Table 12.6, note (b) for financial parameter assumptions.) Source: based on Liu et al., 2011b.

12.8   Strategies and Policies for Radically Transforming the Fossil Energy Landscape

The analysis in this chapter shows that a radical transformation of the fossil energy landscape is feasible for simultaneously meeting the multiple societal objectives of wider access to modern energy carriers, reduced air pollution health risks, enhanced energy security, and major GHG emissions reductions.

12.8.1   Strategies for a Radical Transformation

Developing countries have quite different economic circumstances at present and hence different energy priorities from industrialized countries. The strategies for fossil energy development in developing and industrialized countries will, accordingly, be different in the short term, but necessarily must be convergent in the long term.

Table 12.28 | Thought experiments with zero GHG emissions for global transportation in 2050.

	Global C/B TE	Global G/B TE
Decarbonized synfuels produced for transportation in 2050, EJ/yr LHV	59.8	59.0
FTL via coproduction, %	32.7	29.8
FTL via BTL-RC-CCS, %	67.3	70.2
Decarbonized net electricity generation in 2050, million MWh/yr	3,484	3,621
Crude oil-derived products used in transportation in 2050, EJ/yr LHV	45.0	45.2
Fossil fuel feedstock for making FTL in thought experiment, EJ/yr HHV	45.7	36.3
Biomass for making FTL in thought experiment, EJ/yr HHV (a)	111.7	114.4
Fossil fuel feedstock (coal or NG) needed for Modified Blue Map Scenario relative to use of that feedstock in IEA Blue Map Scenario in 2050	1.46	1.26
Fossil fuel feedstock (coal or NG) needed for Modified Blue Map Scenario relative to use of that feedstock in IEA Baseline Scenario in 2050	0.38	0.81
Fossil fuel feedstock (coal or NG) needed for Modified Blue Map Scenario relative to use of that feedstock in 2005	1.15	1.59
Overall GHG emissions avoided in displacing conventional energy, GtCO$_2$-eq/yr	12.8	12.6
CO$_2$ storage rate, GtCO$_2$/yr	8.47	6.75

a   Estimates of sustainable biomass resource potentials are subject to discussion (e.g., see Chapters 7, 20).

The key for developing countries is to lay a sound foundation for further evolution to low carbon energy systems. In high economic growth developing countries like China and India, reducing conventional pollution is still the most urgent energy challenge. The priority of economic development of these societies tends to lead to increasing emissions of CO$_2$. Accordingly, carbon emissions for such countries will increase in the near term as they complete their industrialization and will subsequently decrease under appropriate sustainable development policies. In the poorest developing countries, economic poverty and associated lack of access to modern forms of energy are the major problems, and growing conventional pollution is a risk as these countries develop. In order to minimize overall carbon emissions from the use of fossil fuels in developing countries, efforts should concentrate on building manufacturing and infrastructure for the most efficient use of hydrocarbon energy resources and flexibility for incorporation of low carbon energy and feedstocks into the energy mix. Technology leapfrogging in energy-using technologies is another essential component of radical transformation strategies.

Although industrialized countries have made major advances in controlling conventional pollution, much more needs to be done in this regard—especially for old coal power plants. Moreover, their energy systems have not been designed for minimal CO$_2$ emissions. At the same time, the energy infrastructure is well established and much of

it is several decades old and ready for replacement or upgrade. Thus, the emphasis going forward in industrialized countries should be on replacing or upgrading obsolete infrastructure, e.g., via repowering sites of old fossil fuel power plants with technologies offering additional capabilities (such as coproduction of electricity and fuels, as discussed in this chapter) and pursuing CCS retrofits.

While different strategies are needed regionally, this chapter has identified four key technology-related requirements as essential for transforming the fossil energy landscape: (i) continued enhancement of energy conversion efficiencies, (ii) carbon capture and storage (CCS), (iii) co-utilization of fossil fuel and biomass in the same facilities, and (iv) coproduction of multiple energy carriers at the same facilities.

Fossil fuel/biomass coprocessing with CCS to coproduce clean liquid fuels and electricity with low greenhouse gas emissions is a technically and economically feasible strategy that can make significant contributions in addressing all the major challenges posed by present energy systems, although additional strategies are also needed to solve all the problems posed by fossil fuels in the electric power and transportation sectors. Moreover, coproduction via fossil fuel/biomass coprocessing with CCS also represents a promising approach for launching CCS technologies in the market early on (facilitating as a result of early experience CCS for power-only systems in both greenfield and brownfield applications). Also, it offers a promising route for gaining early experience using lignocellulosic biomass to make liquid fuels thermochemically at attractive costs. And it can serve as a bridge to enabling CCS as a routine activity for biomass energy (with corresponding negative greenhouse gas emissions) in the post-2030 era. The latter could plausibly become a major industrial development opportunity for economically poor and fossil fuel-poor but biomass-rich regions, while making major contributions to decarbonization of the transport sector worldwide.

No technological breakthroughs are needed to get started with coproduction technologies and strategies that involve fossil fuel/biomass coprocessing with CCS. Most of the technical challenges are engineering issues best addressed via commercial-scale experience (learning by doing).

Despite the multiple attractions of coproduction systems, the concept faces formidable institutional hurdles because of complexities at the systems level. Success requires managing two disparate feedstocks (a fossil fuel and biomass) to provide simultaneously three commodity products (liquid fuels, electricity, and CO$_2$) that would serve three very different markets.

With fossil fuel/biomass coproduction systems, fossil fuel consumers for power generation would have to become consumers of biomass as well. There has been some experience cofiring existing coal power plants with biomass but that has been at biomass levels far more modest than the levels envisioned for the coproduction technologies described here.

Moreover, there is little reason to expect that electricity generators will want to take on the risks of producing and marketing liquid fuels. The oil industry, which could do that, has shown little interest in producing either synfuels from coal or electricity for sale to the electric grid, which offers much lower profit margins than what the oil industry has been accustomed to in exploration and production (E & P).

Yet these obstacles might be surmountable. Coal power generators are coming to realize they will have to embrace CCS in order to survive in a carbon-constrained world and will have to give priority in industrialized countries to CCS for existing coal power plant sites. Coal suppliers who are eager to see coal use expand into synfuels production are coming to realize that this cannot be done without both CCS and coprocessing of biomass under a stringent carbon policy constraint. Biomass suppliers might become interested in the concept once they recognize the potential for greater profits selling biomass to operators of such systems rather than to producers of "pure" biofuels, such as cellulosic ethanol. The coproduction concepts described in this chapter offer the potential for meeting these obligations in a more profitable manner than other routes. And some multinational oil companies might come to embrace synfuels production both because they are running out of E & P investment opportunities as a result of being denied adequate access to the oil resources controlled by national oil companies, and because at high oil and GHG emissions prices, profit margins with coproduction systems can approach historical norms for E & P investments.

Strategic corporate alliances involving partnerships across industries could facilitate deployment of coproduction systems. Encouraging power industry/oil industry partnerships is likely to be especially important. Power companies could, of course, manage the power side of the business but may be uncomfortable with gasification technology – which doesn't resemble the "boiler technology" that they are accustomed to managing. Moreover, the power industry has no experience with either CO_2 capture or management of the geological structures needed for CO_2 storage. The oil industry could, of course, manage liquid fuels production and marketing quite well. It has extensive experience with CO_2 capture (at refineries and chemical process plants for purposes unrelated to CO_2 storage), with CO_2 transport (for enhanced oil recovery), with management of geological structures similar to those that will be used for CO_2 storage, and with gasification of petroleum residuals at both refineries and chemical process plants that could facilitate their becoming comfortable with coal and biomass gasification. Moreover, oil companies that also sell natural gas might become interested in natural gas/biomass coprocessing systems that make fuels and electricity with CCS.

12.8.2   New Policies for a Radical Transformation

A radical transformation of the fossil energy landscape is unlikely to occur without new facilitating public policies. Needed critical broad cross-cutting policies include:

- Carbon mitigation policies in the near term for which implicit GHG emission prices are high enough to make CCS competitive as a routine commercial activity, and which are implemented soon in the context of the expressed G8 support for a global effort to limit the increase in average global temperature due to climate change to 2°C above the pre-industrial level. This goal is written into the Copenhagen Accord and reconfirmed during COP16 in Cancun. The G8 statement in July 2009 noted that this formidable goal will require a global reduction in emissions by at least 50% by 2050 (relative to the 1990 level), and they supported the goal for industrialized countries to achieve 80% reductions by 2050 to help meet the global 50% reduction.

- New air pollution control policies are needed, with highest priority given to pollution from existing coal power plants in industrialized countries and indoor air pollution in developing countries. The analysis in Chapter 12 shows the value of crafting new air pollution control policies and GHG mitigation policies together because of the helpful synergisms that would arise with "co-control" approaches.

- Technological innovation policies in support of the plausible radical transformation described in this chapter should include both support for R&D on promising technological options and incentives for early deployment, including incentives that would encourage needed new inter-industry partnerships. First-of-a-kind projects are always risky, both technologically and financially. Despite the attractive economic features of coprocessing, coproduction, and other technologies discussed in this chapter, without incentives for first-of-a-kind and early deployment projects that offer major public benefits, such technologies will enter the market only slowly or not at all.

High priority should be given to encouraging early CCS action, especially for coal, because if coal is to be widely used in a future carbon-constrained world (via coproduction and coprocessing with biomass or via any other means), so doing will be viable only if the option is available to safely store CO_2 in geological media. For geologic storage, there appear to be neither technical issues that cannot be managed nor economic show-stoppers (see Chapter 13). Nevertheless, there is a pressing need to carry out a significant number of integrated commercial-scale CCS projects worldwide (each involving the annual storage of at least one $MtCO_2$/yr) with an emphasis on storage in deep saline formations, to: (i) address scientific and engineering issues at scale for storage; (ii) provide a sound empirical basis for developing the regulatory and political framework for site selection, permitting, operation, monitoring, and closure of storage sites for routine commercial CCS projects; and (iii) satisfy a wide range of stakeholders as to the viability of CCS as a "gigascale" carbon mitigation option.

The international political framework for early CCS action has already been established. As noted earlier, the G8 Summit in 2008 produced an agreement to sponsor at least twenty commercial-scale, fully integrated CCS demonstration projects worldwide that would be committed by 2010 with the aim of establishing the basis for broad commercial

deployment of CCS technologies after 2020. The G8 reiterated its call for these CCS projects in 2009. In August 2010, a high-level task force in the U.S. created by President Obama issued its report on a comprehensive CCS strategy for the United States that includes bringing five to ten commercial demonstration projects online by 2016.

Much if not all of the incremental cost of CCS for the 20 projects called for by the G8 will probably have to be paid for by governments (individually or collectively). It is likely that carbon prices will be lower initially than what will be needed to make pursuit of CCS a profitable activity for private companies in many, if not most, parts of the world. To minimize spending, governments should aim to pursue projects in which they can maximize the learning about the gigascale prospects of CCS per dollar spent. In this context, the coproduction systems described in this chapter are good candidates for CCS early action projects because they have much lower capture costs than power only systems. If these projects are allowed to compete for government awards for CCS demonstrations, the cost to government might be significantly less than for CCS demonstration projects based on power-only systems. Accordingly, coproduction facilities coprocessing fossil fuel and biomass with CCS, especially those built in coal-rich countries, should be considered seriously as candidates for some of the needed CCS early action projects and supported financially jointly by the governments of several coal-intensive energy economies.

Since it will require at least a decade of demonstration efforts before CCS systems can begin to be routinely deployed, the deployment of CCS systems in conjunction with fossil energy conversion would need to proceed very rapidly thereafter to achieve deep reductions in global GHG emissions from fossil fuel burning by 2050.

Analysis in this chapter indicates that biomass conversion with CCS could play an essential role in enabling continued fossil fuel use. This would be accomplished by off-setting GHG emissions from fossil fuels via the strongly negative emissions of biomass/CCS systems. Two new initiatives needed in this area are:

- New policies should encourage demonstration and commercialization of large biomass gasifiers (300–600 MW biomass input) because these represent a key technology for economically attractive biomass/CCS systems. To date, biomass gasifiers have only been successfully demonstrated at the scale of tens of MW biomass input.

- Detailed assessments should be carried out of the prospects for biomass production for energy on a sustainable basis in ways that minimize conflicts with food production, adverse indirect land-use impacts, and biodiversity. Emphasis should be on agricultural

residues, forest residues (including mill residues, logging residues, diseased tree removals, fuel treatment thinnings, and productivity enhancement thinnings), and the growing of dedicated energy crops on abandoned cropland and other degraded lands. These assessments should be carried out in each of the major world regions.

New policies are also needed to promote universal access to clean cooking fuels (as discussed in detail in Chapter 19, Section 19.2.2) derived from coal and/or biomass systems with CCS (Section 12.5):

- As a basis for new policy, CO_2 storage assessments should be carried out in each of the major regions requiring clean cooking fuels – with financial support from the international community. CO_2 storage prospects are not well known in countries where clean cooking fuels are sorely needed. This is especially true in biomass-rich but coal-poor regions – where consideration of CCS as a carbon mitigation option has probably not been given much thought. Accordingly, "bottom-up" assessments of storage prospects, including the construction of supply curves (storage capacity in tonnes vs cost in US$/t), are needed on a reservoir-by-reservoir basis.

- For regions where there are good prospects for biomass energy with CCS, official development assistance should be expanded to help develop the physical infrastructures and human capacities needed to build and manage large industries based on modern biomass conversion technologies with CCS. This additional ODA should aim to establish this industry so that it can take off as GHG emission prices approach levels high enough that market forces are sufficient to support commercial biomass/CCS activities.

Finally, new public policies are needed to facilitate in the near term industrial collaborations between companies that would produce simultaneously fuels (clean cooking fuels as well as transportation fuels) and electricity from fossil fuels and biomass in regions having significant supplies of both. It would be desirable to identify policy instruments that specify performance rather than technology and maximize use of market forces in meeting performance goals. Promising approaches along these lines include: (i) mandating a Low Carbon Standard for Fuels (Andress et al., 2010; Sperling and Yeh, 2010), (ii) a low carbon standard for electricity generation, perhaps modeled after Renewable Portfolio Standards or green certificate markets; (iii) feed-in tariffs for environmentally-qualified electricity, and (iv) a Universal Clean Cooking Fuel Standard in regions requiring major infusions of clean cooking fuels, perhaps modeled after the "obligation to serve" mandates of the rural electrification programs introduced in the United States in the 1930s. The latter could plausibly facilitate the formation of strategic industrial alliances that would be capable of guaranteeing universal access to clean cooking fuels without major subsidy.

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