LIFE-CYCLE GREENHOUSE GAS EMISSIONS FROM CLEAN COAL, CLEAN GAS AND WIND GENERATORS

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1. Introduction

"Clean coal," "clean gas" or wind-powered generators are often identified as potential ways of reducing greenhouse gas emissions from the U.S. electric power system. The direct emissions of greenhouse gases produced when these generators burn fuel are fairly well understood, but less attention has been given to emissions during the other stages of the life-cycle of these plants – building the plants, mining or drilling for fuel, operating the plants, etc.

Emissions from these other stages of the life-cycle become increasingly important if we contemplate the use of carbon capture and sequestration systems for coal and gas plants. These systems could capture and sequester around 90 percent of the direct emissions from new coal and gas plants. However, they do not reduce emissions from other stages of the life-cycle. On the contrary, as additional industrial processes carbon capture systems introduce life-cycle emissions of their own, and since they increase the amount of energy needed to generate each kilowatt-hour (kWh) of electricity, they also increase the emissions at other stages of the fuel cycle for electricity.

In this paper I assess the complete life-cycle emissions of several cutting-edge power generation technologies: state-of-the art combined-cycle natural gas turbine (CCGT) , pulverized coal (PC) and integrated gasification combined cycle (IGCC) coal plants (with or without carbon capture and sequestration systems), and modern wind farms.

I begin in Section 2 by listing the stages of a generic life cycle for power plants, and then developing a simple model based on these stages, excluding carbon capture and storage. In Sections 3 – 8, I review previous life-cycle studies and other reports to estimate realistic emission intensities for each of these life-cycle stages. Then, in Section 9, I extend the life-cycle model to include the effects of carbon capture and sequestration (CCS) systems, and I develop estimates of the parameters needed for this extended model.

Section 10 pulls together the modeling framework and emission intensities from the previous sections, to present estimates of the total life-cycle emission intensities for each of the technologies discussed here. Finally, Section 11 summarizes my findings and briefly discusses their policy implications.

2. Power Plant Life Cycle Stages

The process of producing electricity from coal, gas or wind can be broken down into several stages, each of which generates greenhouse gas emissions, either directly or indirectly. For this paper, I divide the stages into three categories:

1. Steps related to the production or combustion of fuel, or cleanup of pollutants produced as a result of fuel combustion. For each type of fuel (coal or natural gas), the emission intensity from these fuel-cycle steps is proportional to the amount of fuel that is consumed by the power plant. For example, inefficient coal power plants will require more coal than efficient plants, so they will be responsible for proportionately more emissions during the coal mining stage. Steps included in this category are
    a. fuel extraction, processing and delivery
    b. methane emissions from coal mines and natural gas infrastructure
    c. fuel combustion in power plants
    d. production of materials to control non-CO_2 pollutants

   e. non-CO_2 greenhouse gas emissions from power plants
2. Steps related to the construction and operation of the power plant, and not tied to the fuel cycle. These steps are assumed to produce a fixed amount of greenhouse gas emissions per kWh of electricity, averaged over the life of the plant. Steps in this category include
   a. power plant construction and decommissioning
   b. power plant operation and maintenance
3. Steps related to the capture and sequestration of CO_2. These are assumed to scale up or down depending on how much carbon dioxide is captured from the plant. They include
   a. capture of CO_2 in the power plant
   b. production of materials used in the CO_2 capture process
   c. transport and storage of captured CO_2

The greenhouse gas emissions from steps in category 1 differ between fuels and power plant designs, but for each basic type of plant, they are directly proportional to the amount of that fuel that is used by the power plant. Consequently, emissions in each of these steps would be expected to maintain a fixed ratio relative to each other, regardless of how efficient the power plant is. In particular, emissions in each of these steps are expected to be proportional to the amount of carbon dioxide produced during combustion in the power plant. This makes it possible to use a simple model for all the emissions related to the fuel cycle and non-CO_2 pollution cleanup:

$$\text{fuel cycle emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right) = \text{combustion emissions}\left(\frac{\text{gCO2}}{\text{kWh}}\right) \times \begin{pmatrix} 1 \\ + \text{ fuel production ratio } (\%) \\ + \text{ methane leakage ratio } (\%) \\ + \text{ pollution control materials ratio } (\%) \\ + \text{ N2O emission ratio } (\%) \end{pmatrix} \tag{1}$$

That is, for any given plant, the total life-cycle emission of greenhouse gases, per kilowatt hour of electricity, is equal to the amount of CO_2 produced directly by that plant, scaled up by fixed percentages that represent all the other greenhouse gas emissions during the fuel cycle. These ratios differ between different fossil fuels (coal vs. gas), and to a lesser extent between different types of plant that use the same fuel. However, they are assumed to be constant for plants of the same basic type (e.g., IGCC), regardless of how efficient that plant is. (i.e., each individual plant may have a different "combustion emissions" value, but all plants of the same type will share the same "fuel production ratio," "methane leakage ratio," etc.)

It should be noted that the ratios used in Equation (1) are all expressed in terms of global warming intensity, e.g., the methane leakage ratio is equal to the ratio between the grams of CO_2-equivalent (gCO2e) of upstream methane leaks and the number of grams of CO_2 produced during combustion in the power plant. In this case, the gCO2e for the methane would be 25 times higher than the number of grams of methane that leaked, because methane causes 25 times more radiative forcing than carbon dioxide on a gram-for-gram basis (IPCC 2007: 212).

The greenhouse gas emissions from steps in category 2 are generally reported in units of grams of CO_2-equivalent per kilowatt hour of electricity produced, over the life of the plant (gCO2e/kWh). They may differ from one type of power plant to another, but are assumed to be constant for different plants of the same basic type. Adding these emissions to the fuel-cycle

emission shown in Equation (1) gives a complete model for all power plant emissions, at least for power plants that do not use carbon capture and sequestration.

$$\begin{aligned}\text{life cycle emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right) &= \text{fuel cycle emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right)\\ &+ \text{power plant construction/decommiss. emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right)\\ &+ \text{power plant operation/maintenance emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right)\end{aligned} \tag{2}$$

For renewable power plants, the fuel cycle emissions would be zero, and emissions can be calculated using only the last two terms of Equation (2).

Carbon capture and sequestration systems add extra sources and sinks of greenhouse gases, and increase the intensity of fuel consumption. A more complete model including these effects is presented in Section 6.1.

In Sections 3 - 8 I estimate the appropriate emission factors for each of the stages shown in Equations (1) and (2). Then in Section 9 I use this model (and the more complete one for CCS systems) to calculate the total life-cycle emissions for wind farms and several types of coal and natural gas power plants.

3. Fuel Combustion

Most of the greenhouse gas emissions from coal and gas power plants are in the form of carbon dioxide that is produced when hydrocarbon fuels are combusted in the power plant. The emissions produced by combustion of fuel per kWh of electricity can be calculated via Equation (3):

$$\begin{aligned}\text{combustion emissions}\left(\frac{\text{g CO}_2}{\text{kWh electricity}}\right) &= \text{fuel carbon intensity}\left(\frac{\text{kg CO}_2}{\text{MBtu heat}}\right) \times \left(\frac{1000\text{ g}}{\text{kg}}\right) \times \left(\frac{1\text{ MBtu}}{10^6\text{ Btu}}\right)\\ &\times \text{power plant heat rate}\left(\frac{\text{Btu heat}}{\text{kWh electricity}}\right)\end{aligned} \tag{3}$$

That is, the amount of carbon dioxide produced per kWh of electricity due to combustion of fuel is simply the product of the carbon intensity of the fuel, and the heat rate of the plant (the amount of fuel needed per kWh of electricity generated), with appropriate conversion factors. These factors are discussed in the following two sections.

3.1. Fuel Carbon Intensity

The carbon intensity of natural gas and coal varies depending on the exact composition of the fuel. For this paper, I assume that electric plants use the average mix of fuel supplied to electric plants in the U.S., as reported in the EPA's greenhouse gas inventory for 2007(EPA 2009b, § 2.2). These values are shown in Table 1. They have not varied significantly in recent years.

Table 1. Carbon intensity of fossil fuels supplied to U.S. electric utilities

Fuel	Carbon intensity ($kg\ CO_2/MBtu$)
Natural gas	53.1
Coal	94.5

(EPA 2009b, § 2.2)

3.2. Power Plant Heat Rates

The heat rate of fossil-fuelled power plants is a measure of their efficiency – lower values indicate more efficient plants (a 100% efficient plant would have a heat rate of 3413 Btu/kWh). The heat rate varies widely among power plants, and strongly affects the amount of carbon dioxide released per unit of electricity generated. In this paper, I assume that new fossil-fuelled plants would have the heat rates reported by the U.S. Energy Information Administration (EIA) for state-of-the-art plants that could have begun construction in 2008 (EIA 2009a).[1] These are shown in Table 2, along with the average heat rate for existing coal and natural gas power plants.

Table 2. Heat rate and emissions intensity of U.S. fossil-fuelled power plants

Fuel	Technology	Heat rate[a] (Btu/kWh)	Combustion emissions[b] (gCO2/kWh)
Coal	New pulverized coal (PC)	8,740	826
Coal	New integrated coal-gasification combined cycle (IGCC)	7,450	704
Coal	Existing U.S. coal-fired power plants	10,326	975
Natural gas	Advanced combined cycle gas turbines (CCGT)	6,333	336
Natural gas	Existing U.S. combined cycle gas turbines (CCGTs)	7,483	397

[a] Based on higher heating value of fuel. Existing plants calculated from EIA (2009b); new plants from EIA (2009a)
[b] calculated using Equation (3) with data from Table 1

For comparison, Table 3 shows the heat rate reported for fossil-fuelled power plants in a number of previous life-cycle studies. The reference heat rate for new pulverized coal power plants PC plants (8,740 Btu/kWh) falls roughly in the middle of all the designs that were assessed, or on the low end if hypothetical, future designs for 2020 are ignored. The reference values for IGCC and CCGT plants are lower than assumed in most other life-cycle studies of the same type of plant, but that may be appropriate for this paper, given that heat rates are expected to decline in the future.

Table 3. Heat rates for coal and natural gas power plants reported in previous life-cycle studies

Technology	Study	Notes	Heat Rate[a] (Btu/kWh)
PC	(Spath and Mann 2004)		11,851
	(Spath et al. 1999)	US average	10,666
	(Koornneef et al. 2008)	Netherlands avg.	10,158
	(Spath et al. 1999)		9,751
	(Odeh and Cockerill 2008b)	subcritical	9,669
	(Hondo 2005)		9,274
	(Berry et al. 1998)		9,101
	(Tahara et al. 1997)		8,751
	(Pacca and Horvath 2002)		8,751
	(Odeh and Cockerill 2008b)	supercritical	8,619
	(Proops et al. 1996)	supercritical	8,126

[1] The EIA estimates heat rates for prototype plants and for "nth-of-a-kind" plants that could eventually be built once each technology matures. In this paper I use the nth-of-a-kind heat rates.

Technology	Study	Notes	Heat Rate[a] (Btu/kWh)
	(Spath et al. 1999)	low-emission boiler	8,126
	(Koornneef et al. 2008)	ultra-supercritical	7,729
	(Mayer-Spohn and Blesl 2007)		7,670
	(Mayer-Spohn and Blesl 2007)		7,420
	(Viebahn et al. 2007)	2020 vintage	7,420
	(Viebahn et al. 2007)	2020 vintage	6,965
IGCC	(Odeh and Cockerill 2008a) based on (Proops et al. 1996)		9,751
	(Odeh and Cockerill 2008b)		9,175
	(Gorokhov et al. 2002) cited by (Ruether et al. 2004)		8,619
	(Ruether et al. 2004)		8,533
	(Nomura et al. 2001)		7,904
	(Mayer-Spohn and Blesl 2007)		7,757
	(Proops et al. 1996)		7,584
	(Mayer-Spohn and Blesl 2007)		7,584
	(Viebahn et al. 2007)		6,826
CCGT	(Nomura et al. 2001)		7,857
	(Hondo 2005)		7,828
	(Berry et al. 1998)		7,420
	(Spath and Mann 2000)		6,994
	(Odeh and Cockerill 2008b)		6,812
	(Proops et al. 1996)		6,440
	(Mayer-Spohn and Blesl 2007)		5,936
	(Dones et al. 2005)		5,936
	(Viebahn et al. 2007)	2020 vintage	5,688

[a] Based on higher heating value (HHV) of fuel

4. Fuel Production and Delivery

Substantial amounts of energy are used to extract coal or gas from the ground, prepare these fuels for combustion, and deliver them to the power plant. These emissions have been assessed in many previous studies, several of which are shown in Table 4.

During the extraction phase, greenhouse gas emissions result from burning fuel to operate mining equipment, as well as further upstream, in the process of making the equipment used for mining or drilling. Estimates of these emissions vary significantly, depending on the conditions in which the fuel is found (e.g., above ground or underground coal mines), the condition of the fuel (e.g., how much CO_2 must be rejected from natural gas to prepare it for the pipeline). Estimates can also vary depending on the methods used by researchers.

Emission estimates for the process of transporting fuel to the power plant also vary significantly. These can be affected by the distance the fuel must travel, as well as the methods used to get it there (pipeline, barge, train, etc.).

The estimates of the combined emissions due to extraction and transport in Table 4 range from 0.7 to 12.4 percent of the direct emissions when coal is burned, or 2.0 to 18.2 percent of the direct emissions when natural gas is burned. It is not clear which of these estimates is most "typical" for coal or gas plants in the U.S., so I will adopt the median values among these studies as my reference value. These are marked with bold type in Table 4 (4.2 percent of the combustion emissions for coal, and 13.1 percent of the combustion emissions for natural gas, which is considered an average value for European power plants).

Table 4. Greenhouse gas emissions due to extraction and transport of fossil fuels

Fuel	Study	Extraction (ratio vs. combustion)	Transport (ratio vs. combustion)	Total (ratio vs. combustion)	Note
Coal	(Mayer-Spohn and Blesl 2007)	0.7%	incl in extr.	0.7%	lignite
	(Ruether et al. 2004)	0.6%	0.3%	0.8%	
	(Viebahn et al. 2007)	2.1%	incl in extr.	2.1%	lignite
	(Berry et al. 1998)	2.2%	0.1%	2.4%	UK
	(Hondo 2005)	1.1%	1.8%	2.9%	imported to Japan
	(Spath et al. 1999)	1.2%	1.8%	3.0%	Illinois, underground
	(Mayer-Spohn and Blesl 2007)	4.2%	incl in extr.	**4.2%**	anthracite
	(Viebahn et al. 2007)	5.1%	incl in extr.	5.1%	anthracite
	(Spath and Mann 2004)	5.9%	incl in extr.	5.9%	
	(Koornneef et al. 2008)	1.8%	6.0%	7.8%	Netherland mix
	(Nomura et al. 2001)	6.1%	2.3%	8.4%	imported to Japan from China
	(Proops et al. 1996)	9.9%	incl in extr.	9.9%	
	(Proops et al. 1996)	12.4%	incl in extr.	12.4%	
Gas	(Berry et al. 1998)	1.5%	0.5%	2.0%	direct from North Sea
	(Dones et al. 2005)	2.1%	2.3%	4.3%	Netherlands mix
	(Nomura et al. 2001)	8.7%	1.8%	10.4%	LNG to Japan
	(Proops et al. 1996)	11.0%	incl in extr.	11.0%	UK
	(Viebahn et al. 2007)	11.7%	incl in extr.	11.7%	Germany
	(Dones et al. 2005)	3.7%	9.3%	**13.1%**	European average
	(Mayer-Spohn and Blesl 2007)	13.4%	incl in extr.	13.4%	
	(Dones et al. 2005)	4.5%	10.5%	14.9%	Italy mix

Fuel	Study	Extraction (ratio vs. combustion)	Transport (ratio vs. combustion)	Total (ratio vs. combustion)	Note
	(Dones et al. 2005)	4.5%	10.5%	14.9%	Austria mix
	(Spath and Mann 2004)	17.5%	incl in extr.	17.5%	
	(Hondo 2005)	14.1%	4.1%	18.2%	LNG to Japan

5. Methane Emissions

Methane is a potent greenhouse gas, causing 25 times more radiative forcing than carbon dioxide on a ton-for-ton basis (IPCC 2007: 212). The production and transport stages of both coal and natural gas cause releases of methane, and these releases are among the most significant greenhouse gas emissions for coal and gas power other than the carbon dioxide released during fuel combustion.

5.1. Coal Mines

When biomass is converted to coal, some of the biomass is also converted to methane, which remains embedded in the coal until it is disturbed. Much of this methane is released to the atmosphere as a result of coal mining. Underground coal seams tend to contain more methane than surface seams, and consequently more methane is released per ton of coal from underground mines than from surface mines. Methane content also varies among different coal formations, whether they are above or below ground (Longwell and Rubin 1995; Ruether et al. 2004).

Although methane is a potentially valuable fuel, these emissions have so far proven difficult to capture: surface mines are an open environment where methane does not achieve high enough concentration to be easily collected, and underground mines must be constantly ventilated to prevent dangerous build-up of methane – which in turn means that methane in the exhaust air is too diluted to collect easily.

Coal mining in the U.S. in 2007 generated about 0.116 kg of methane emissions per million Btu worth of coal produced. Applying a GWP of 25 yields an average release of methane of 2.89 kg CO2e per million Btu of heat.[2] As noted previously in Table 1, the coal used for electricity production in the U.S. in 2007 produced about 94.5 kgCO2 per million Btu of heat. The ratio between these two values (2.89/94.5) indicates that emissions of methane from coal mines are equivalent to about 3.1 percent of the direct emissions released when coal is combusted.

For the reference coal plants assessed in this paper, I adopt the assumption that coal mining causes upstream methane emissions equivalent to **3.1 percent** of the carbon dioxide produced when the fuel is combusted.

This ratio has fallen in recent years, as U.S. coal production has shifted from underground to aboveground mines, and as underground mining has shifted from more "gassy" sites to less "gassy" ones (EPA 2009c). Figure 1 shows the U.S. trend between 1990 and 2007.

[2] The U.S. produced 1.145 billion short tons of coal in 2007 (EPA 2009c, Table A-104). When combusted, this coal produced 23.3 quadrillion Btu of heat (at 20.3 million Btu per short ton)(EIA 2008, Table A5). The mining of this coal led to the release of 2.74 million metric tons of methane (EPA 2009a, Table 3-2).

The EPA indicates that methane emissions from coal mines could be 24 percent higher or 16 percent lower than the figure cited above (using a 95 percent confidence interval). This suggests that methane emissions from coal mines could be around 2.6 to 3.8 percent of the direct emissions from combusting the coal.

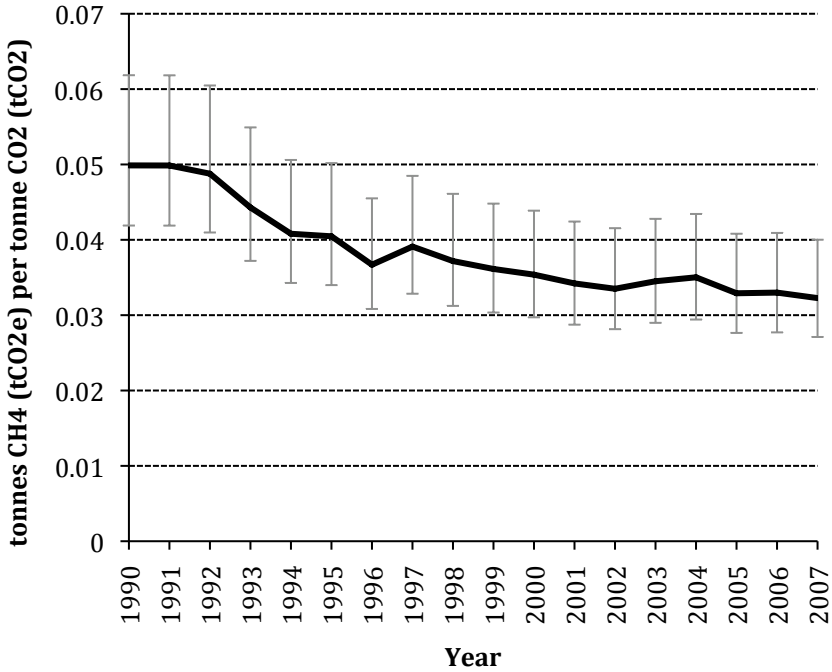

Figure 1. Ratio between CH_4 emissions from U.S. coal mines and CO_2 emissions from coal combustion

5.2. Natural Gas Infrastructure

In 1996, the U.S. EPA published the results of a major study of methane leakage from the U.S. natural gas system (Harrison et al. 1997). They found that about 1.4 percent ± 0.5 percent of gross natural gas production escaped to the atmosphere before reaching its final destination. The main sources of these emissions are small leaks throughout the system (0.67%), venting from pneumatic devices (0.20%), venting from regulators and meters (0.14%), maintenance operations (0.08%) and compressor exhaust (0.08%); other sources total 0.22%.

Kirchgessner (1997) reports that other studies have typically estimated U.S. gas leakage rates between 1 and 4 percent, or possibly higher if flaring and venting are included. Harrison (1997) do not discuss venting or flaring at the wellhead.

For this paper, I assume that 1.4 percent of natural gas is emitted to the atmosphere before reaching final customers. Thus, for every 100 tons of natural gas that is produced, 1.4 tons are lost and 98.6 tons reach customers. Natural gas is about 95 percent methane (EPA 2009b: A-51), so this means about 1.33 tons of methane (equivalent to 33.3 tCO2e) are released for every 98.6 tons of natural gas that reach customers. The 98.6 tons of natural gas that reach customers produce 267.5 tons of carbon dioxide when combusted (at a rate of 2.72 tons of carbon dioxide per ton of natural gas).[3] Taking the ratio of emissions due to leaks and due to direct combustion gives 33.3/267.5 = 0.124.

[3] U.S. pipeline natural gas contains about 95% methane (which produces 44 tons of CO_2 per 16 tons ton of fuel) and 3.6% ethane higher hydrocarbons (which produce about 44 tons of CO_2 per 15 tons of fuel)(EPA

For this paper, I assume that upstream methane leakages have an impact on climate equal to **12.4 percent** of the emissions due to combustion of natural gas.

Dones (2005) estimate leakage rates of 0.1–1.4 percent for European countries, averaging 0.7 percent. With a GWP of 25, methane leakage in this study corresponds to about 1-13% of the direct emissions from combustion, averaging 6.3%. Methane leakage is highest for Austria, which obtains most of its natural gas from the Russian Federation. Similarly, Lelieveld (2005) report leakage of 1.4 percent from Russian pipelines connecting to western Europe.

Berry (1998: 90) reports that methane leakage in the UK has been estimated at 2-11% in previous studies, but these estimates may include a certain amount of theft. More reliable industry estimates are around 0.9-1%, mostly from the older, low-pressure distribution system. For a power plant connected by new, high-pressure pipelines to a North Sea gas platform, Berry estimates total leakage around 0.19 percent, with a climate impact equivalent to 1.7 percent of the direct emissions from combusting the fuel.

6. Non-Carbon Dioxide Emissions Control and Emissions

6.1. Emissions Control

U.S. power plants must control emissions of a number of pollutants, notably nitrogen (NOx) and sulfur (SOx) compounds. NOx emissions from coal and gas power plants are generally removed from the exhaust stream by use of selective catalytic reduction, a process which consumes significant amounts of ammonia. SOx emissions from coal plants are controlled via flue-gas desulfurization, a process which generally uses significant amounts of limestone or lime.

Substantial amounts of energy are needed to prepare these materials, particularly limestone or lime for coal plants. The desulfurizing reaction also produces significant amounts of carbon dioxide (Spath et al. 1999)

Most previous life-cycle studies give little attention to the greenhouse gas emissions generated when ammonia and limestone are prepared and used for power plants. However, several that do investigate this are shown in Table 5, with the emissions from the pollution control system shown as a ratio versus the direct emissions from fuel combustion.

For this study, I use the emission rates highlighted in bold text in Table 5. For PC plants, Spath (1999) appears to provide an estimate that most closely matches the context of this paper (a new plant meeting New Source Performance Standards), although this also has the highest upstream emissions of the four cases presented. For IGCC and CCGT plants, only one study estimated the greenhouse gas emissions due to the pollution control system.

2009b: A-52). Summing 0.95 x 44/16 + 0.036 x 44/15 gives a weighted average of 2.72 tons CO_2 per ton of natural gas.

Table 5. Greenhouse gas emissions due to production and use of ammonia and lime/limestone for fossil-fuelled plants

Technology	Study	Emissions from pollution control materials (ratio vs. combustion)	Notes
PC	(Berry et al. 1998)	0.8%	
	(Odeh and Cockerill 2008a)	3.9%	
	(Spath et al. 1999)	4.3%	US average
	(Spath et al. 1999)	**4.9%**	US plant meeting New Source Performance Standards
IGCC	(Odeh and Cockerill 2008a)	**3.9%**	
CCGT	(Spath and Mann 2000)	**0.1%**	

6.2. Non-CO_2 Greenhouse Gas Emissions

Coal and gas power plants produce some other greenhouse gases in addition to their carbon dioxide emissions. The most significant of these are N_2O and methane. Several of the studies reviewed for this paper assessed N_2O emissions; their findings are shown in Table 6. For this paper, I use the median value reported for each technology, and assume that climate impact of **N_2O emissions from PC, IGCC and CCGT plants are equal to 1.7%, 1.0% and 0.8%**, respectively, of the combustion emissions from these plants.

Table 6. N_2O emissions due to production and use of ammonia and lime/limestone for fossil-fuelled plants

Technology	Study	N_2O emissions (tCO2e, ratio vs combustion)
PC	(Mayer-Spohn and Blesl 2007)	1.0%
	(Mayer-Spohn and Blesl 2007)	1.3%
	(Berry et al. 1998)	2.1%
	(Pacca and Horvath 2002)	2.5%
IGCC	(Gorokhov et al. 2002) cited by (Ruether et al. 2004)	0.0%
	(Ruether et al. 2004)	0.0%
	(Mayer-Spohn and Blesl 2007)	1.0%

Technology	Study	N_2O emissions (tCO2e, ratio vs combustion)
CCGT	(Mayer-Spohn and Blesl 2007)	1.2%
	(Spath and Mann 2000)	0.1%
	(Mayer-Spohn and Blesl 2007)	0.8%
	(Berry et al. 1998)	1.0%

Coal plants also release some methane in their exhaust, due to incomplete combustion of the fuel. This effect was not explicitly estimated in any of the life-cycle studies reviewed for this paper, so I do not attempt to quantify it.

7. Power Plant Construction and Decommissioning

7.1. Fossil Plants

Table 7 shows estimates of the direct and indirect emissions due to construction and decommissioning of coal and natural gas power plants, reported by several previous life-cycle studies. In general, the more detailed studies find higher emissions for these phases. So for this paper, I adopt the construction-phase estimates by Spath (2000; 1999) for PC and CCGT plants, and by Reuther (2004) for IGCC plants. These have been highlighted in bold text in the table.

Previous studies gave little attention to the emissions caused by decommissioning of power plants. For this paper, I adopt an estimate of **0.1 gCO2e/kWh for this phase for all three fossil technologies.**

Table 7. Greenhouse gas emissions due to construction and decommissioning of fossil power plants

Tech-nology	Study	Manufact. / construction (gCO2e/kWh)	Plant decommis-sioning (gCO2e/kWh)
PC	(Odeh and Cockerill 2008b)	~0	
	(Tahara et al. 1997)	0.7	
	(Koornneef et al. 2008)	1.0	
	(Odeh and Cockerill 2008a) based on (Berry et al. 1998)	1.0	10% of constr.
	(Mayer-Spohn and Blesl 2007)	1.1	0.0
	(Pacca and Horvath 2002)	1.2	
	(Koornneef et al. 2008)	1.3	
	(Proops et al. 1996)	1.5	0.0
	(Mayer-Spohn and Blesl 2007)	1.8	0.1
	(Hondo 2005)	3.6	
	(Spath et al. 1999)	**4.5**	
	(Odeh and Cockerill 2008a) based on (Spath et al. 1999)	5.2	
IGCC	(Odeh and Cockerill 2008b)	0.0	
	(Gorokhov et al. 2002) cited by (Ruether et al. 2004)	0.6	0.1
	(Proops et al. 1996)	1.1	0.0
	(Mayer-Spohn and Blesl 2007)	1.3	0.1
	(Mayer-Spohn and Blesl 2007)	1.3	0.1
	(Ruether et al. 2004)	**2.3**	
CCGT	(Odeh and Cockerill 2008b)	0.0	
	(Mayer-Spohn and Blesl 2007)	0.3	0.0
	(Proops et al. 1996)	1.0	0.1
	(Nomura et al. 2001)	1.1	
	(Dones et al. 2005)	2.0	
	(Spath and Mann 2000)	**2.0**	included in constr.
	(Hondo 2005)	2.7	

7.2. Wind Farms

More attention has been given to the emissions due to manufacturing, installation and decommissioning of wind farms. Table 8 shows estimates from several dozen on this topic. However, many of the available studies are based on outdated (sub-megawatt) wind turbine designs and/or envision offshore wind farms. This study is intended to focus on the potential

emissions due to current-generation on-shore wind farms, so the ten studies that assess current-generation turbines for on-shore use are shown with bold text in Table 8.

Unfortunately, even these studies produce dramatically varying estimates of the net greenhouse gas emissions for construction and decommissioning of wind farms. For example, some account for the use of recycled steel and other metals during the manufacturing/construction phase, while others treat it as a "negative" emission during the decommissioning phase, while others do not account for it at all.

These ten studies report a range of net emissions from 4.9 to 12.0 gCO2e/kWh, with a median of 7.1 gCO2e/kWh. As a conservative estimate, I will assume that building and decommissioning farms produce a net release of **10 gCO2e/kWh**.

Table 8. Greenhouse gas emissions due to construction and decommissioning of fossil power plants

Study	Year of Install-ation	Manufact-uring and construc-tion (gCO2e / kWh)	Decom-mission-ing (gCO2e / kWh)	Technology
(Lenzen and Wachsmann 2004)	2000	2.6		600 kW, 55m coastal site
(Lenzen and Wachsmann 2004)	2000	4.2		600 kW, 65m inland site
(Mayer-Spohn and Blesl 2007)	2007	4.2	0.1	off-shore
(Lenzen and Wachsmann 2004)	2000	4.5		600 kW, 55m coastal site
(Vestas 2006b)	**2006**	**10.9**	**-6.0**	**onshore, 105 m, vestas v90**
(Mayer-Spohn and Blesl 2007)	**2007**	**4.7**	**0.3**	**on-shore**
(Vestas 2006b)	2006	9.5	-4.1	offshore, 80 m, vestas v90
(Elsam 2004)	**2004**	**36.7**	**-30.3**	**onshore, 78 m tower, vestas v80**
(Frankl 2004)	2004	6.3	0.7	vestas, on shore, 37m
(Norton 1999)	**1999**	**6.5-9.1**		**UK, materials only**
(Vestas 2006a)	**2006**	**10.5**	**-3.5**	**onshore, 80 m, vestas v82**
(Elsam 2004)	2004	34.0	-26.8	offshore, 60 m tower, vestas v80
(Frankl 2004)	**2004**	**6.7**	**0.6**	**onshore, tubular 60m, deep foundation**
(Lenzen and Wachsmann 2004)	2000	7.3		600 kW, 65m inland site
(Frankl 2004)	**2007**	**8.0**	**0.2**	**onshore, 124m tower, like Enercon E112 (prototype)**
(Frankl 2004)	2004	7.3	0.6	offshore, 25 km, lattice 100m, tripod
(Frankl 2004)	2004	8.3	0.5	offshore, 25 km, tubular 60m, caisson

Study	Year of Install-ation	Manufact-uring and construc-tion (gCO2e / kWh)	Decom-mission-ing (gCO2e / kWh)	Technology
(Frankl 2004)	2004	8.5	0.5	offshore, 40 km, tubular 60m, caisson
(Frankl 2004)	2004	8.9	0.5	offshore, 25 km, tubular 60m, monopile
(Schleisner 2000)	1997	9.5	0.2	onshore, 18 500 kW turbines
(Frankl 2004)	**2004**	**10.2**	**1.3**	**Enercon, direct drive, on shore, deep foundation, 67m tower**
(Pacca and Horvath 2002)	1997	11.7		onshore wind farm, 4480 turbines (via IO modelling)
(Frankl 2004)	**2004**	**10.6**	**1.3**	**Enercon, direct drive, on shore, shallow foundation, 67m tower**
(Viebahn et al. 2007)	**2020**	**12.0**		**future design**
(Schleisner 2000)	1997	15.8	0.7	offshore, 500 kW turbines
(Hondo 2005)	1997	20.3		small farm, 400 kW turbines
(Hondo 2005)	1997	29.5		small farm, 300 kW turbines
(Norton 1999)	1995	30.0		Japan, seismically reinforced
(Proops et al. 1996)	1996	34.5	0.1	
(Nomura et al. 2001)	1982	39.4		30m tower
(Lenzen and Wachsmann 2004)	2000	48.1		600 kW, 55m tower, coastal
(Lenzen and Wachsmann 2004)	2000	77.0		600 kW, 65m tower, inland

8. Power Plant Operation and Maintenance

8.1. Coal and Natural Gas Plants

I have identified only two life-cycle studies that attempt to quantify the greenhouse gas emissions due to operation and maintenance of fossil-fuelled power plants. An early paper by Kreith (1990) estimates that maintenance of a fluidized-bed coal plant would cause 28 gCO2e/kWh of emissions, and Ruether (2004) estimates that 6.9 gCO2e/kWh would be released during operation and maintenance of an IGCC coal plant in the U.S. No available studies estimate the impact of operation and maintenance of natural gas plants. Consequently, for this paper I assume that **operation and maintenance activities at all coal or gas plants produce 6.9 gCO2e/kWh of emissions**.

8.2. Wind Farms

Three studies estimate the greenhouse gas emissions due to operation and maintenance of wind farms. These are summarized in Table X. Estimates of the impact of operation and

maintenance of onshore wind farms range from zero to 0.79 gCO2e/kWh. For this study, I will assume a value of **0.63 gCO2e/kWh**, which is the median of the estimates for on-shore sites.

Table 9. Greenhouse gas emissions due to construction and decommissioning of fossil power plants

Study	plant maintenance	Technology
(Vestas 2006a)	0.00	**onshore**, 80 m, vestas v82
(Vestas 2006b)	0.00	**onshore**, 105 m, vestas v90
(Vestas 2006b)	0.12	offshore, 80 m, vestas v90
(Frankl 2004)	0.28	offshore, 25 km, tubular 60m, caisson, minimum maint
(Frankl 2004)	0.43	offshore, 25 km, lattice 100m, tripod
(Frankl 2004)	0.45	offshore, 25 km, tubular 60m, caisson
(Frankl 2004)	0.45	offshore, 25 km, tubular 60m, monopile
(Frankl 2004)	0.47	offshore, 40 km, tubular 60m, caisson
(Frankl 2004)	0.55	**onshore**, Vestas, 37m tower
(Frankl 2004)	**0.59**	**onshore**, 0 km, tubular 60m, deep
(Frankl 2004)	**0.67**	**onshore**, 124m tower, like Enercon E112 (prototype)
(Elsam 2004)	0.71	**onshore**, 78 m tower, vestas v80
(Frankl 2004)	0.75	**onshore,** Enercon, direct drive, shallow foundation, 67m
(Frankl 2004)	0.79	**onshore,** Enercon, direct drive, deep foundation, 67m
(Elsam 2004)	0.85	offshore, 60 m tower, Vestas v80

9. Carbon Capture and Sequestration

In recent years, much attention has been given to the possibility of using carbon capture and sequestration (CCS) systems to collect carbon dioxide from power plants, either before or after the main combustion cycle, and then store it in underground or deep-sea reservoirs. CCS systems are now at the prototype stage, and several studies have been published assessing their effect on energy and emissions.

9.1. Emissions from Carbon Capture System

In this paper, I consider CCS systems based on amine absorption of CO_2 for PC and CCGT power plants, and a system based on pre-combustion Rectisol absorption for IGCC plants. Both

types of system would remove 90 percent of the carbon dioxide that would otherwise be emitted by the power plant.

Although they are highly effective at removing carbon dioxide from the power plant's exhaust, CCS systems also generate some greenhouse gas emissions of their own. The most significant of these occur during production of the solvents used for these systems. Additional energy is also needed for compression and transport of captured CO_2 (possibly causing upstream emissions of CO_2, depending on the accounting system), and some of the captured CO_2 may be released during transport or after storage.

Table 10 shows the amount of emissions from several studies of similar plants, during each of these stages. The Viebahn (2007) study investigates plants that are most similar to the reference design for this paper, so I adopt their estimate for each technology. However, one adjustment must be made to these values. In the next section, extra energy required within the plant to run the CO_2 capture system (including compression of the captured CO_2) will be incorporated into an adjustment for the plant's overall efficiency. Therefore, emissions associated with the compression of captured CO_2 should not be incorporated here. The extra energy required for compressing CO_2 amounts to about 1 percent of the plant's gross output (i.e., it is responsible for about 1% of the plant's combustion-based emissions). With this factor removed from the CCS-related CO_2 emissions, I obtain reference values for CCS-related CO_2 emissions of **4.4 percent, 3.1 percent and 3.7 percent for PC, IGCC and CCGT plants**, respectively. These values are given as ratios relative to the carbon dioxide produced during fuel combustion.

Table 10. Life-cycle greenhouse gas emissions from carbon dioxide capture systems (ratio vs. combustion emissions)

Technology	Study	Solvent production	CO_2 compression / transport / storage	CO_2 leakage	Total CCS-related emissions
PC+CCS	(Spath and Mann 2004)	not shown	0.1%	0.4%	n.a.
	(Koornneef et al. 2008)	1.3%	0.1%	0.0%	1.4%
	(Odeh and Cockerill 2008b)	1.4%	0.8%	incl. in transp.	2.2%
	(Odeh and Cockerill 2008b)	2.2%	incl. in captr.	incl. in captr.	2.2%
	(Viebahn et al. 2007)	3.4%[a]	2.0%[a]	0.0%	5.4%
IGCC+CCS	(Odeh and Cockerill 2008b)	~0%	incl. in captr.	incl. in captr.	0.0%
	(Viebahn et al. 2007)	2.3%[a]	1.8%[a]	0.0%	4.1%
CCGT+CCS	(Spath and Mann 2004)	not shown	0.1%	0.3%	n.a.
	(Viebahn et al. 2007)	2.6%[a]	2.1%[a]	0.0%	4.7%
	(Odeh and Cockerill 2008b)	6.4%	incl. in captr.	incl. in captr.	6.4%

[a] energy for compression of CO_2 is included in "CO_2 capture materials" column

9.2. Effect of Carbon Capture System on Power Plant Efficiency

CCS systems require energy in the form of both heat and electricity, in order to cool flue gases to allow absorption of CO_2, heat solvents to release CO_2, move solvents and flue gases through the system, compress collected CO_2, etc. The Intergovernmental Panel on Climate Change has reviewed previous studies of the performance of potential CCS systems, and identified ranges and representative values for the amount by which these systems increase energy requirements for various types of power plant (IPCC 2005). These values are shown in Table 11. For this paper, I adopt the IPCC's representative value for each type of power plant.

Table 11. Increase in energy requirements of coal and gas plants due to carbon capture and sequestration

Technology	Low	High	Representative value
PC	24%	40%	31%
IGCC	14%	25%	19%
NGCC	11%	22%	16%

(IPCC 2005: 343)

9.3. Life-Cycle Emission Model, Including Carbon Capture

I now extend the model given in Equations (1) and (2), to incorporate the effects of CCS systems on the life-cycle emissions of coal and gas power plants. The first change reflects the fact that emissions due to the CCS system are proportional to the amount of CO_2 that is generated during combustion in the power plant. Consequently, two terms can be added to Equation (1), reflecting the carbon captured by the CCS system and the amount of increased emissions due to the CCS system. The modified equation becomes

$$\text{fuel cycle emissions}\left(\frac{\text{gCO2e}}{\text{kWh}}\right) = \text{combustion emissions}\left(\frac{\text{gCO2}}{\text{kWh}}\right) \times \begin{pmatrix} 1 \\ +\ \text{fuel production ratio (\%)} \\ +\ \text{methane leakage ratio (\%)} \\ +\ \text{pollution control materials ratio (\%)} \\ +\ \text{N2O emission ratio (\%)} \\ -\ \text{sequestration ratio (\%)} \\ +\ \text{CCS system emissions (\%)} \end{pmatrix}. \tag{4}$$

Here, the "sequestration ratio" is 90 percent of combustion-based CO_2, and CCS system emissions are given for each type of plant in Section 9.1.

The second adjustment accounts for the change in the plant's net efficiency due to addition of the CCS system. This has two effects.

First, power plants with CCS systems must consume more fuel in order to produce each kWh of useful output, in a proportion equal to the extra energy requirements shown in Table 11.

Second, much of the power plant's infrastructure must be devoted to producing energy for the CCS system, which means that emissions per kWh due to construction/decommissioning and operation/maintenance of the plant must also be scaled up. If the CCS system needed all of its energy in the form of electricity, then it would be reasonable to assume that the construction

and O&M emissions must scale up by the same factor as the fuel consumption (neglecting the extra emissions due to construction and maintenance of the CCS system itself). However, in reality, most of the extra energy for CCS systems is supplied in the form of heat (IPCC 2005: 117), so the electrical components need not be scaled up as much as the thermal components to accommodate the CCS system. On the other hand, the CCS system is likely to add significant equipment and operating impacts of its own to the plant. So, for the purpose of this paper, I adopt the simplifying assumption that plant-related emissions (construction and O&M) per useful kWh rise by the same share as the fuel consumption increases. That is, I assume that the equipment and maintenance needed to fuel and run the CCS system have similar emission intensities (per unit of fuel input) as the original power plant.

With these adjustments, Equation (2) becomes

$$\begin{aligned}&\text{life cycle emissions}\left(\tfrac{\text{gCO2e}}{\text{kWh}}\right)=\\&(1+\Delta E)\times\text{fuel cycle emissions}\left(\tfrac{\text{gCO2e}}{\text{kWh}}\right)\\&+\ (1+\Delta E)\times\text{power plant construction/decommiss. emissions}\left(\tfrac{\text{gCO2e}}{\text{kWh}}\right)\\&+\ (1+\Delta E)\times\text{power plant operation/maintenance emissions}\left(\tfrac{\text{gCO2e}}{\text{kWh}}\right)\ ,\end{aligned}\tag{5}$$

where ΔE fractional increase in energy requirements due to addition of the CCS system (discussed in Section 9.2).

In the next section, I will apply the original model to the reference power plants, and the extended model to power plants with carbon capture and storage, to estimate the total life-cycle greenhouse gas emissions from each type of plant.

10. Total Life-Cycle Emissions from Power Plants

Tables 12–14 gather together all the parameters for coal, gas and wind power plants that have been presented earlier in this paper.

Table 12. Fuel-cycle related emissions for fossil-fuelled power plants

Technology	Combustion emissions (gCO2/kWh)	Fuel production ratio (vs combustion)	Methane leakage ratio (vs combustion)	Pollution control ratio (vs combustion)	N2O emissions ratio (vs combustion)
PC	826	4.2%	3.1%	4.9%	1.7%
IGCC	704	4.2%	3.1%	3.9%	1.0%
CCGT	336	13.1%	12.4%	0.1%	0.8%

Table 13. Power-plant related emissions for fossil-fuelled power plants

Technology	Construction & decommissioning (gCO2e/kWh)	Operation & maintenance (gCO2e/kWh)
PC	4.6	6.9
IGCC	2.4	6.9
CCGT	2.1	6.9
Wind	10.1	0.63

Table 14. CCS-related emissions for fossil-fuelled power plants

Technology	CCS component emissions (vs combustion)	CCS sequestration (vs combustion)	CCS ΔE (vs non-CCS plant)
PC+CCS	4.4%	90%	31%
IGCC+CCS	3.1%	90%	19%
CCGT+CCS	3.7%	90%	16%

These parameters can be used with equations (4) and (5) [or (1) and (2) for non-CCS plans) to calculate the emissions for each stage of the life cycle, for each type of power plant. These emission intensities are shown in Table 15, along with a rough estimate of the life-cycle emission intensity of existing U.S. fossil-fuelled power plants. These emissions are given in units of grams of CO_2-equivalent per kWh of electricity generated.

Table 15. Life-cycle emissions for existing and new coal, gas and wind generators

	Combustion less sequestration (gCO2e/kWh)	Fuel production (gCO2e/kWh)	Methane leakage (gCO2e/kWh)	Pollution control (gCO2e/kWh)	N2O exhaust (gCO2e/kWh)	CCS components (gCO2e/kWh)	Construction & decomm. (gCO2e/kWh)	Operation and maintenance (gCO2e/kWh)	Total life-cycle emissions (gCO2e/kWh)
Existing U.S. coal+gas[a]	807.1	45.8	37.5	33.1	12.5	0.0	3.8	6.9	946.7
New PC	825.9	34.7	25.6	40.5	14.0	0.0	4.6	6.9	952.2
New IGCC	704.0	29.6	21.8	27.5	7.0	0.0	2.4	6.9	799.2
New CCGT	336.3	44.1	41.7	0.3	2.7	0.0	2.1	6.9	434.1
New PC+CCS	108.2	45.4	33.5	53.0	18.4	47.6	6.0	9.0	321.3
New IGCC+CCS	83.8	35.2	26.0	32.7	8.4	26.0	2.9	8.2	223.0
New CCGT+ CCS	39.0	51.1	48.4	0.4	3.1	14.4	2.4	8.0	166.9
Wind	0.0	0.0	0.0	0.0	0.0	0.0	10.1	0.6	10.7

[a] Uses PC factors for all coal plants (69% of U.S. fossil electricity), with an average heat rate of 10,326 Btu/kWh; and CCGT factors for all gas plants (31% of U.S. fossil elec.), with an average heat rate of 8,126 Btu/kWh.

These emissions are also plotted in Figure 2, and Figure 3 shows more detail for the wind and CCS generators. Wind farms have life-cycle emissions about two orders of magnitude lower than new fossil plants without CCS, or about one order of magnitude below the cleanest CCS plant. Interestingly, although CCS dramatically reduces the direct emissions from coal and gas plants, it increases the other life cycle emissions. These other emissions are significant enough that even with CCS, new PC systems are only slightly cleaner than new CCGT systems without CCS.

In these figures I have drawn a line marking an emission level 80 percent below the current U.S. fossil mix. Climate experts are increasingly reporting that the world should aim for emission levels around 80 percent below current (or possibly 1990) levels. One way to achieve this in the electricity system would be to replace current fossil plants with plants that produce 80 percent lower emissions on a life-cycle basis. It is apparent from Figures 2 and 3 that this cannot be done with any of the power plant designs considered here other than new CCGT+CCS or wind plants, or some mixture of higher-emitting plants with these very low-emission plants.

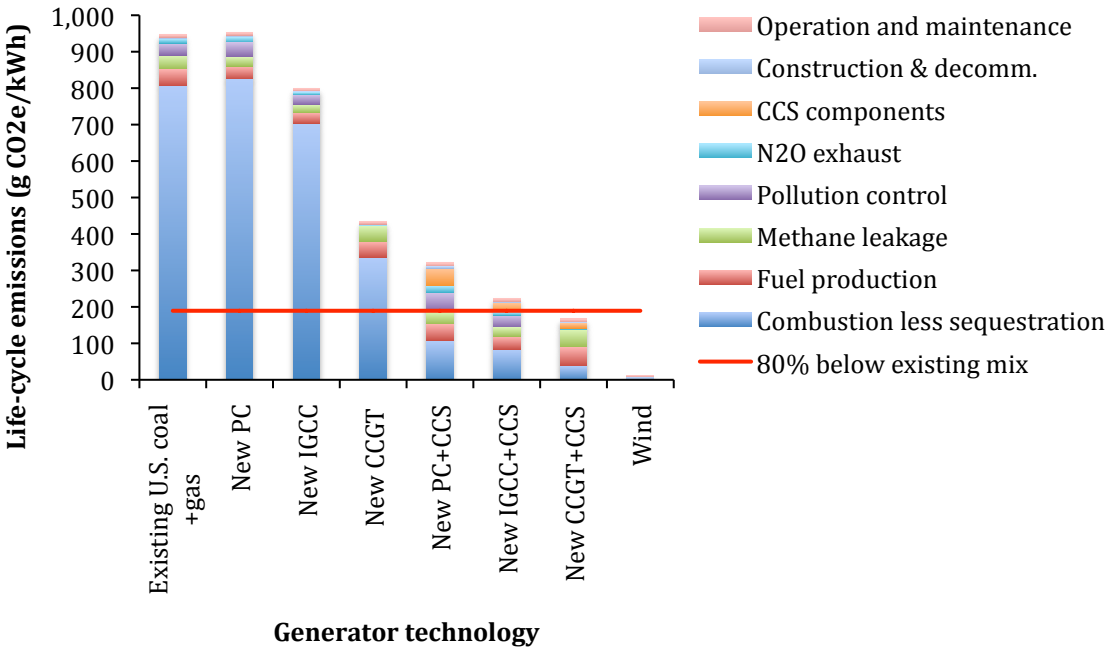

Figure 2. Life-cycle greenhouse gas emissions from coal, gas and wind power plants, with and without carbon capture systems

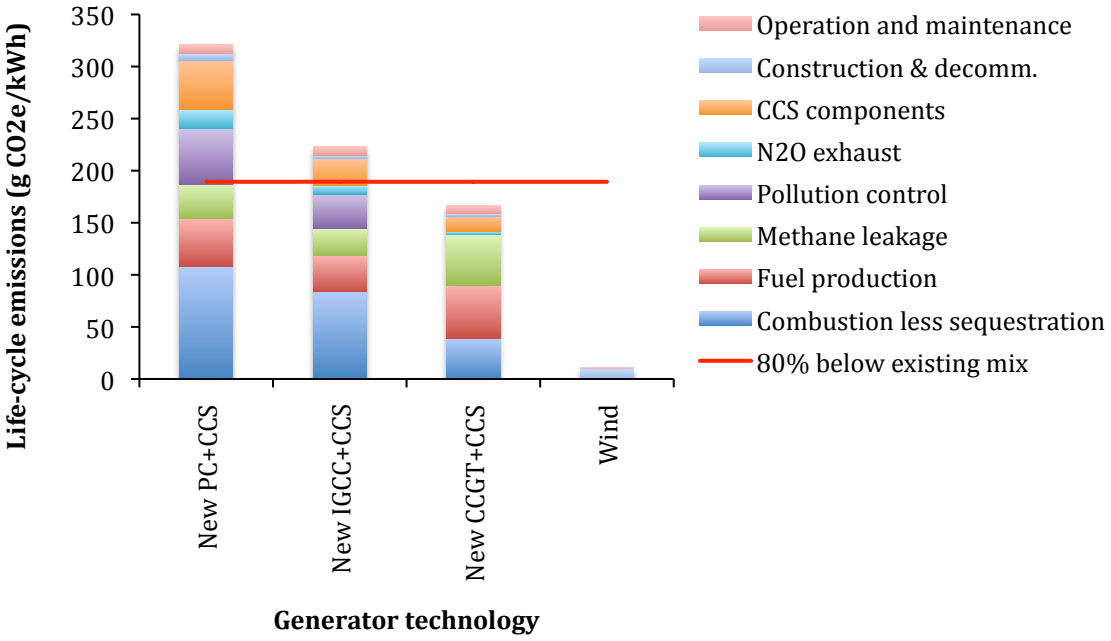

Figure 3. Life-cycle greenhouse gas emissions from coal and gas generators with and carbon capture systems, and from wind farms

11. Conclusions

For this study I used a simple but comprehensive model to estimate the greenhouse gas emissions produced at all stages of the life cycle of power plants, including direct emissions due to fuel combustion, as well as the emissions generated when producing fuel, building and maintaining power plants, etc. Parameters for this model were obtained by reviewing a number of previous life-cycle studies of power plants and choosing realistic emission values for each stage of the life cycle.

This work produced several findings:

1. Direct emissions due to combustion dominate the life-cycle emissions of fossil power plants without carbon capture and sequestration (CCS) systems. However, emissions from other stages of the life cycle grow in absolute and relative terms when direct emissions are reduced via CCS. These other emissions limit the ability of power plants with CCS to achieve radical emission reductions. For example, pulverized coal plants with CCS may reduce direct emissions by nearly 90 percent; however, when other stages of the life-cycle are included, the full reduction is only 65 percent.

2. Wind power plants have life-cycle emissions nearly 100 times lower than existing U.S. coal and gas plants, and over 10 times lower than the cleanest foreseeable fossil technology, combined cycle natural gas turbines with CCS.

3. Many of the parameters in this study are open to uncertainty. Future research could estimate these parameters more carefully and assess the effect of their uncertainty on the life-cycle emissions of power plants.

4. More attention should be given to reducing emissions from non-combustion stages of the life cycle of fossil-fuelled electricity, especially the production of amines and limestone, methane leakage from coal mines and natural gas plants, and energy used in the production and transport of fuels.

5. It appears to be impossible to achieve emission levels 80 percent below the current U.S. coal and gas electricity mix by relying predominantly on coal plants with CCS. If the U.S. seeks to achieve emission reductions on that scale, it will need to take another approach. One possible path would be a nearly 50-50 mix between IGCC coal and CCGT gas, if adequate natural gas supplies can be developed and CCS can be rolled out universally and cost-effectively. A better possibility may be to rely more heavily on renewable resources, such as wind power.

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