Energy penalty estimates for CO_2 capture: Comparison between fuel types and capture-combustion modes

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ABSTRACT

Carbon capture from power plants holds the key to any significant reduction in CO_2 emissions. This work considers the energy penalty related to CO_2 capture from coal, natural gas and fuel oil-based power plants. We evaluate the minimum thermodynamic work for CO_2 capture, and then estimate achievable targets. All the three modes of capture-combustion: pre-combustion, post-combustion, and oxy combustion, are considered. The low CO_2 concentration in natural gas-based power plants translates into the highest capture energy per ton of CO_2. However, the lowest energy penalty of 10% is obtained with pre-combustion capture in natural gas-based power plants (versus 17% for coal-based power plants). The highest energy penalty of about 20% is found for oxy combustion capture from coal-based power plants. In general, pre-combustion capture seems to provide the lowest energy penalties.

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1. Introduction

The tremendous scale of CO_2 emissions and the associated global warming present an urgent environmental challenge [1,2]. The first and necessary step in mitigating CO_2 emissions is CO_2 capture, before any subsequent sequestration or utilization. The largest stationary source of CO_2 emissions worldwide are power plants, followed by refineries, steel and cement production, and petrochemical plants [3,4]. Hence, these are the main sources where carbon capture and storage/utilization (CCS/U) is expected to be applied in the coming years. In this work we evaluate the energy penalty for CO_2 capture from power plants for different fuel types: coal, natural gas and fuel oil.

Different aspects of CO_2 capture from power plants have been studied and the literature is vast. Many studies focus on a particular CO_2 capture technology (e.g., absorption, adsorption, membrane, etc.), while others focus on a particular type of power plant (e.g.,

coal). Instead, we present a comprehensive technology-agnostic study based on the thermodynamic minimum separation energy. In the context of this study, we first review general works that present a thermodynamic analysis or report energy penalties for different capture modes in power plants.

Hammond and Akwe [5] reported an exergy and economic analysis to evaluate the effect of CO_2 capture for NGCC (natural gas combined cycle) plants. In their study, 90% capture was considered using a commercial amine process. A significant energy penalty of 21% was determined, as well as a concomitant increase in the power generation cost. The study by Davison [6] is one of few to consider the three different types of combustion capture, namely pre-combustion, post-combustion, and oxy combustion. In this study, performance, cost and emissions data are presented for coal and natural gas-fired power plants. Davison reported lower estimated costs of CO_2 capture and compression for coal-based power plants than for natural gas-based power plants. The lowest electricity generation cost was found for pre-combustion capture. Rubin et al. [7] also evaluated the CO_2 capture cost for three major fossil fuel power plant types — pulverized coal, NGCC and IGCC (integrated gasification combined cycle) systems using coal. A modified definition of energy penalty was introduced in their study, namely, the increase in plant energy input per unit of product or output. This measure directly determines the increase in

resource consumption, environmental burden and economic cost associated with producing an additional amount of electricity. According to this measure, pulverized coal-fired plants with CO_2 capture are found to require 31% more coal per kWh than reference plants without capture.

House et al. [8] calculated the thermodynamic work required for the various steps of post-combustion CCS (carbon capture and storage) from pulverized coal-fired power plants. They concluded that an energy penalty of 40% could be easily achieved, while an energy penalty of 29% is proposed as a reasonable target. Bhown and Freeman [9] calculated the theoretical minimum energy required for post-combustion capture from a coal-fired power plant. For 100% capture, the minimum energy penalty for a flue gas stream with 13% CO_2 is 5.1% of the electrical energy generated by the power plant. Strube and Manfrida [10] studied the effect of capture on plant performance for a pulverized coal power plant with post-combustion CO_2 capture, an IGCC and an oxy-fuel power plant with cryogenic CO_2 capture. They concluded that the IGCC shows the highest efficiency and the lowest energy penalty. However, the captured CO_2 for this option also had the lowest purity, and required further treatment. On the other hand, low energy efficiency was reported for oxy combustion due to the high energy requirement for air separation.

Manzolini et al. [11] studied the integration of a SEWGS (Sorption Enhanced Water Gas Shift) reactor for carbon capture in NGCC. They performed simulation studies on different configurations of SEWGS and three reference cases for electricity production, namely, without carbon capture, with post-combustion carbon capture by MEA (monoethanolamine) and with pre-combustion carbon capture by MDEA (N-methyldiethanolamine). Comparison in terms of net electric efficiency and CO_2 avoided indicated that SEWGS achieves a lower efficiency penalty (7.5%) than MEA (8.4%) and MDEA (8%). Cormos [12] studied pre-combustion capture applied to an IGCC plant, and evaluated the technical, economic and environmental performance of the plant with and without CCS. He reported an energy penalty in terms of net plant efficiency of 7.0–9.5% with CCS. Li and Liang [13] performed an Aspen Plus simulation of a retrofitted 1000 MW pulverized coal-fired power plant in China, and reported an energy penalty of 8.6% for 90% capture and 6% for 50% capture. The retrofitted plant simulated in this study comprised of the conventional power generation system together with a post-combustion unit and additional equipment.

Jenni et al. [14] discussed expert assessments of the range of likely energy penalties for coal-based power plants in 2025, considering six capture technologies for three different policy scenarios. In this study, the energy penalty is defined as the fractional decrease in output per unit input. It was found that a scenario of worldwide carbon pricing could lead to a 1–10% decrease in the mean energy penalty across all technologies, and a scenario of increased US government funding in research and development could lead to a 6–14% decrease in the mean energy penalty. Pre-combustion capture was found to show the smallest improvement in energy penalty from R&D funding and carbon pricing, while post-combustion capture with membranes and other approaches were expected to show the largest improvement. Kuramochi et al. [15] evaluated the techno-economic prospects of CO_2 capture from distributed energy systems. Their findings show that in the near term (2020–2025), the energy penalty for CO_2 capture ranges from 23 to 30% for coal-fired plants and from 10 to 28% for natural gas-fired plants. The latter energy penalty might reduce to 4–9% beyond 2030. Goto et al. [16] reviewed previous studies on the efficiency penalty for post-combustion CO_2 capture from coal-fired power plants. In this study, the efficiency penalty was defined as the net decrease in the power output of a power plant caused by the implementation of CO_2 capture and compression.

Efficiency penalties of about 10% were obtained, irrespective of the type of power plant and the type of coal. However, the choice of CO_2 capture technology (chemical absorption, adsorption, membrane, etc.) was found to influence the efficiency penalty reduction significantly (for e.g., novel membranes could lower the efficiency penalty by 5% or more).

Tola and Pettinau [17] reported a techno-economic analysis for coal combustion and gasification. Three coal-fired power plant technologies were compared: (1) USC (ultra-supercritical) plants with conventional flue gas treatment, (2) USC plants with SNOX technology for combined removal of sulphur and nitrogen oxides, and (3) pre-combustion IGCC plants. Detailed process simulations showed that, without CCS, USC is more efficient than IGCC. However, after the implementation of CCS, IGCC becomes more efficient than USC. Cormos [18] reported a techno-economic analysis for a coal-based power plant with calcium looping as the capture method. The reported energy penalty of 5–7.5% for combustion based power plants with calcium looping is lower than for gasification-based power plants with calcium looping and for post-combustion capture with gas–liquid absorption.

More recently, Basavaraja and Jayanti [19] compared four gas-fired power plants with carbon capture: two based on pressurized oxy combustion and two based on chemical looping combustion. Detailed energy and thermodynamic analyses yielded net efficiencies in the range of 31–52% for the four plants. They concluded that chemical looping combustion plants should be preferred as they can accommodate CCS with only 2% loss in thermal efficiency. Supekar and Skerlos [20] examined the thermal efficiency penalties for pulverized coal power plants with post-combustion CO_2 capture. They concluded that contrary to previously lower reported values, capture can decrease the plant thermal efficiency by as much as of 11–23%.

The majority of power plants currently use coal as the primary fuel source, though there has been a recent growth in the number of natural gas-based power plants. The above studies have individually considered one or a few particular aspects of carbon capture from power plants with the performance evaluated in terms of energetics, economics and/or efficiencies. In this work we report a comprehensive study comparing the most common fuel types (coal, natural gas and fuel oil) and the three capture modes (pre, post, and oxy combustion). Results compare the capture energy and the corresponding energy penalties for the various scenarios. The energy penalties are based on the thermodynamic minimum separation energy and a heuristic scaling factor to determine technologically achievable energy penalties. Different from previous studies, our results do not depend on a particular choice of separation technology or process implementation.

2. CCC (Carbon capture and concentration)

Carbon capture and concentration (CCC) is imperative for subsequent sequestration/utilization of CO_2. The energy required to run a capture process is known as the energy penalty. The energy penalty gives an indication of the amount of energy that needs to be spent for carbon capture in relation to the energy generated by the plant. In other words, it is the relative increase in energy input or the relative decrease in electric power output of a power plant with capture compared to the same power plant without capture. More specifically, Bhown and Freeman [9] define the energy penalty as the energy required to capture a ton of CO_2 divided by the electrical energy generated by the power plant per ton of CO_2 emitted.

Energy penalty is perhaps the most objective consideration for the acceptability of a proposed capture technology. However, given the scale of CO_2 emissions, the footprint and capital costs of a capture plant are also critical. The footprint is particularly

important for retrofitting existing plants. Thus, the key challenges for carbon capture are energy penalty, plant footprint, and capital costs. However, due to the lack of reliable and consistent cost data, the present analysis is based on the energy penalty. In order to compare various capture options and establish practical targets for the capture energy, we use the thermodynamic separation energy limit.

2.1. Thermodynamic limits for capture energies

Capturing CO_2 from an emission source is a generic gas separation problem. Thus, the minimum capture energy is the minimum thermodynamic work required to separate a gaseous component from its mixture. This is given by Eq. (1), which is based on the change in Gibbs free energy (ΔG_{mix}) of a reversible separation process for an ideal gas mixture [21].

$$E_{\min} = \Delta G_{mix} = -T \Delta S_{mix} = -RT \, \Sigma_i(x_i \ln x_i)$$
$$= -RT \left[x_{CO_2} \ln x_{CO_2} + (1 - x_{CO_2}) \ln (1 - x_{CO_2}) \right] \quad (1)$$

The above equation assumes: (1) The emission or capture source is an ideal binary mixture of CO_2 and inerts, where the inerts constitute all the remaining components. (2) The separation produces a 100% CO_2 stream.

The minimum thermodynamic work to separate a binary ideal gas mixture into 2 pure component streams is given by Eq. (1). The minimum separation work results only from the mixing entropy. The real separation energy is always higher than this thermodynamic limit. No specific assumptions about the separation technology or the detailed composition of the flue gas have been made. These factors are accounted for implicitly by the heuristic scaling factor that is used to estimate realistic energy penalties, as explained in the following paragraph.

Eq. (1) is valid not only for CO_2 separation, but also for any other separation, as long as the appropriate mole fraction is used. While obtaining pure CO_2 is practically infeasible, Eq. (1) provides the minimum theoretical work. In this study, **"theoretical minimum energy"** refers to this thermodynamic limit. We furthermore assume that the separations take place at room temperature. Industry experience suggests that a practical future energy target for a real separation process is about 5–6 times the thermodynamic limit given by Eq. (1). This rule of thumb has been established for both air separation [22] and CO_2 absorption via monoethanolamine [9]. In the absence of actual process information, the **"target energy"** for a separation process is therefore defined as five times this thermodynamic limit. Energy consumption obtained from process simulation and optimization by assuming suitable efficiencies for the devices/equipment involved is called the **"actual minimum energy"** and is reported in Table 2. When the actual energy consumption for an industrial separation process is known, it is called the **"actual energy"**.

2.2. Modes of CCC and their evaluation

In this work, we consider the separation and capture needs (see Fig. 1) for all three modes of combustion capture, namely pre, post, and oxy combustion.

Post-combustion capture is attractive for retrofitting existing power and chemical plants. Since air is used for combustion, the majority of the flue gas consists of N_2, and CO_2 concentrations are low. Thus, the energy for post-combustion capture is the energy required to separate CO_2 from N_2, moisture, and other components in the flue gas such as SO_x and NO_x. In our calculations we have neglected the energy required for separating moisture as it is expected to be small in comparison to the CO_2 capture energy.

An oxy combustion process uses enriched air for combustion. Preparing enriched air adds to the energy penalty. The flue gas from oxy combustion has a very low N_2 content, so the flue gas from oxy combustion is wet CO_2. Neglecting the energy for condensing water, the CO_2 capture energy for an oxy combustion process equals the energy required for air separation.

A pre-combustion process involves the gasification of a fossil fuel with enriched air to obtain a mixture of CO and H_2. This is converted to a CO_2-H_2 mixture via the WGS (water-gas shift) reaction. Then, H_2 is separated from CO_2 and combusted to generate power. Thus, pre-combustion capture involves two separation steps; the first to separate oxygen from air, and the second to separate CO_2 from H_2. Thus, the pre-combustion capture energy is the sum of the energies for air separation and CO_2-H_2 separation. Here again, we neglect the effect of moisture.

This work has generalized the CO_2 capture technologies in three main groups. However there are several options for pre-combustion capture that considerably affect the general configuration of the process. For example, the use of chemical or physical solvents for CO_2 capture does not require fuel reforming/gasification with pure oxygen. This might lead to quite different results. The benchmark, technology-agnostic, energy penalties that are presented in this work can serve as a reference for more detailed process simulations.

2.3. Energy calculations for CCC

The separation steps for the three modes of combustion in Fig. 1 are different, and the concentrations of CO_2 in the capture streams also differ significantly. Furthermore, these concentrations vary with the fossil fuel type.

2.3.1. Post-combustion capture process

Typical CO_2 concentrations in the flue gas streams (in mol%) are 3% for natural gas combustion, 8% for fuel oil, and 15% for coal [23,9]. Note that the 8% CO_2 concentration for fuel oil combustion corresponds to the use of 100% excess air. The separation energy for this combustion mode (CO_2-N_2 separation) is computed from Eq. (1) for these compositions – this is the theoretical minimum, E_{min}.

2.3.2. Oxy combustion process

The minimum work (W_{min}) required for air separation is calculated as follows:

$$W_{\min} = \left[- \Sigma_i(x_i \ln x_i) + \Sigma_j(\beta_j) \Sigma_i \left(y_{ij} \ln y_{ij} \right) \right] RT \quad (2)$$

Here, x_i refers to the molar composition of component i in the air stream, β_j refers to the amount of stream j (oxygen-rich and nitrogen-rich) resulting from the separation, and y_{ij} refers to the molar composition of i in the jth stream. Typically, air with a molar composition of 0.2095 O_2, 0.7812 N_2 and 0.0093 Ar is used to obtain 0.2040 mol of 99.5% oxygen. Using Eq. (2), W_{min} is 1.19 kJ/mol of air, or 331 kWh/mol of air. The power required to compress air to 5.5 atm dominates for a real air separation process. At an adiabatic compression efficiency of 70%, this power amounts to *RT ln(5.5)/0.70 = 6.07 kJ/mol of air* or *1690 kWh/mol of air*. As expected, this value corresponds to five times the minimum work, W_{min}.

The amount of oxygen required for oxy combustion varies with the fuel type. Thus, the capture energies for different fuel types are:

1. For natural gas, the combustion reaction is $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$. Therefore, the actual work for air separation is *57.8 kJ/mol of CO_2* or *365 kWh/ton CO_2*.
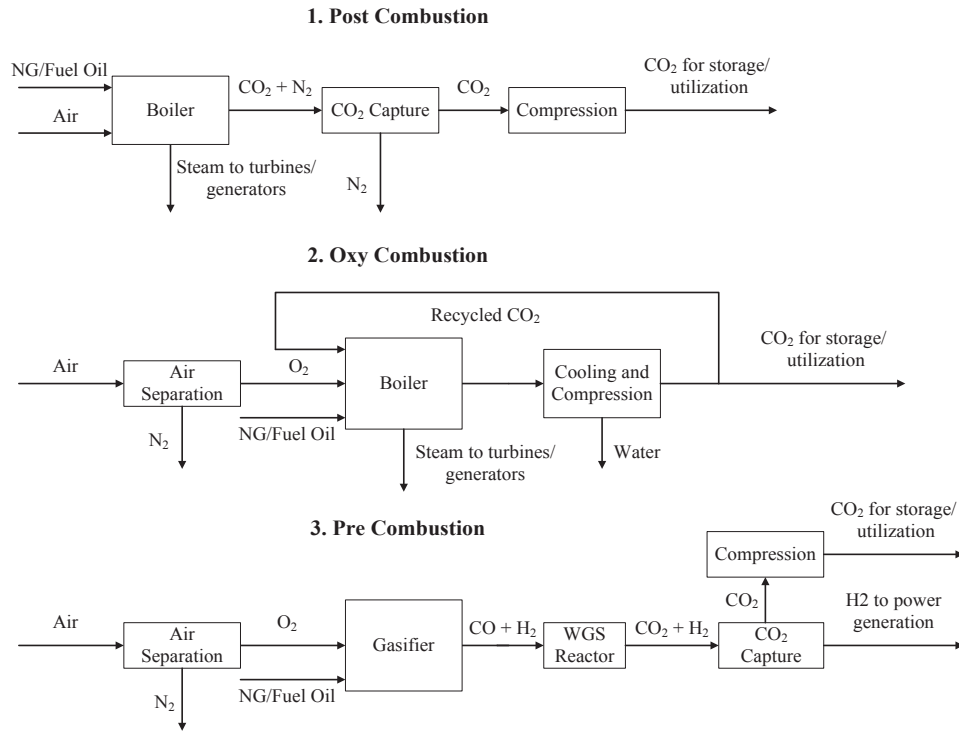
1. Post Combustion

2. Oxy Combustion

3. Pre Combustion

Fig. 1. Flowsheet for three modes of combustion for power generation.

2. For fuel oil, the combustion reaction is $[CH_2] + 3/2O_2 \rightarrow CO_2 + H_2O$. Therefore, the work for air separation is *43.3 kJ/mol of CO_2 or 274 kWh/ton CO_2*.

3. For coal, the overall combustion reaction is written as $[CH] + 5/4O_2 \rightarrow CO_2 + 1/2H_2O$, if we assume coal to have a H/C ratio of 1. Therefore, the work for air separation is *36.1 kJ/mol of CO_2 or 228 kWh/ton CO_2*.

Since combustion is always done with excess oxygen, the actual energy requirements will be slightly higher. In our calculations, we assume combustion with 5% excess oxygen and the separation energies reported above are increased by 5% in Table 1. Lower excess oxygen is possible for boilers equipped with low NO_x installations [24]. This would lower the air separation energy penalty; our estimates are thus conservative.

2.3.3. Pre-combustion capture process

In this process, two separation steps are involved. For the CO_2 separation, the CO_2 concentration in the flue gas stream needs to be estimated for each fuel type.

1. For natural gas, the reactions are $CH_4 + 1/2O_2 \rightarrow CO + 2H_2$ (partial oxidation) and $CO + H_2O \rightarrow CO_2 + H_2$ (water-gas shift). Therefore, the flue gas contains 25% CO_2 and 75% H_2.

2. For fuel oil, the reactions are $[CH_2] + 1/2O_2 \rightarrow CO + H_2$ (partial oxidation) and $CO + H_2O \rightarrow CO_2 + H_2$ (water-gas shift) and the flue gas contains 33% CO_2.

3. For coal (represented as $[CH]$), the reactions are $[CH] + 1/2O_2 \rightarrow CO + 1/2H_2$ (partial oxidation) and $CO + H_2O \rightarrow CO_2 + H_2$ (water-gas shift). The flue gas therefore contains 40% CO_2.

Using these mole fractions, the minimum capture energies (E_{min}) for different modes are *35 kWh/ton CO_2* for natural gas, *30 kWh/ton CO_2* for fuel oil, and *26 kWh/ton CO_2* for coal.

To compute the air separation energy requirement, we determine the oxygen requirements for each fuel. For natural gas, partial oxidation requires 1/4 of the oxygen for complete oxidation, which is the same as the CO_2 content. Similarly, for fuel oil and coal, partial oxidation requires 1/3 and 40% of the oxygen for complete oxidation, respectively. With these, actual air separation energies for pre-combustion capture for all the three types of fuel are *96 kWh/ton CO_2* (383/4 for natural gas, 287/3 for fuel oil, and 240/2.5 for coal).

3. Total capture energies and penalties

Based on the calculations reported in Section 2, total CO_2 capture energies (in kWh/ton CO_2) are computed for the three fuel types and for pre, post, and oxy combustion (Table 1). For air

Table 1
Target/actual energies (kWh/ton CO_2) for CCC in various modes for different fuels.

Fuel	Post-combustion		Oxy combustion	Pre-combustion			
	CO_2–N_2 separation		Air separation	Air separation	CO_2–H_2 separation		Total
	E_{min}	E_{target}	E_{actual}	$E_{actual1}$	E_{min2}	$E_{target2}$	E_{target}
Natural gas	70	350	383	96	35	176	272
Fuel oil	55	270	287	96	30	150	246
Coal	44	220	240	96	26	132	228

Note: For pre-combustion, total $E_{target} = E_{actual1} + E_{target2}$.

separation, only the "actual energy" (E_{actual} and $E_{actual1}$) is reported, while for CO_2–N_2 and CO_2–H_2 separation, both the "theoretical minimum energy" (E_{min} and E_{min2}) and the "target energy" (E_{target} and $E_{target2}$) are reported. As mentioned earlier, E_{target} values are assumed to be five times the thermodynamic limits given by Eq. (1).

As a comparison, actual minimum separation energy requirements (in kWh/ton CO_2) that have been reported in literature for different technologies are also presented in Table 2. The values for an adsorption-based separation process are taken from our studies for VSA (vacuum swing adsorption) with an achieved purity-recovery of 90% [25]. In this study, a simple 4-step VSA cycle with light product pressurization was considered and an actual minimum energy of 131 kWh/ton CO_2 was calculated to achieve a purity-recovery of 90% for a feed with 15% CO_2. This corresponds to roughly three times the theoretical minimum energy of separation reported in Table 1 for post-combustion separation for a 15% CO_2 stream and hence falls below the target energy. For other CO_2 concentrations, the actual minimum energy required for the adsorption process is eight times the theoretical minimum energy for a 3% CO_2 stream and four times theoretical minimum energy for 8% CO_2 stream. For the pre-combustion process, the actual minimum energy for CO_2–H_2 separation by the adsorption process is roughly 2.5 times the theoretical minimum energy E_{min2} for all feed concentrations.

Our simulation studies [26] for a 3-stage membrane cascade for feed compositions ranging from 3% to 40% indicate actual minimum energy requirements between 682 and 40 kWh/ton CO_2 for a cross-flow model, which represents the best-case scenario. For a mixed-flow model the energy cost falls between 2054 and 115 kWh/ton CO_2, which represents the worst-case scenario (see Table 2). It can be seen that as the feed concentration increases, the energy requirements for both models become closer. In all cases, the separation energies are close to or higher than the target energies that were obtained from taking five times the theoretical minimum separation energy. White et al. [27] recently studied the performance of a membrane-based pilot plant for CO_2 capture from the flue gas stream of a coal-fired power plant containing one ton CO_2 per day. They report stable operation during three extended runs conducted over a period of two years with CO_2 capture rates of circa 90%. Energy penalties were not reported.

Our target energies can be further compared with actual minimum separation energies for monoethanolamine absorption. Karmakar and Kolar [28] reported a minimum reboiler heat energy requirement of 1047 kWh/ton CO_2 for 90% capture of a 15% CO_2 stream, well above our target energy. In another study for a coal-fired power plant, chemical absorption based on aqueous ammonia was found to require 1600 kWh/ton CO_2 [29]. Goto et al. [16] summarized the performance of several commercial and investigated solvents in post-combustion capture of coal-fired power plants. The lowest regeneration energy was reported for ammonia absorption, which is 611 kWh/ton CO_2, or roughly 14 times the theoretical minimum separation energy for post-combustion capture with coal in Table 1.
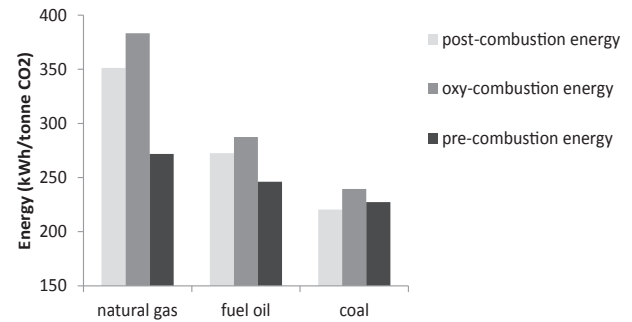

Fig. 2. Energy cost for different methods for CO_2 capture.

To estimate energy penalties, the generation efficiency (based on LHV (lower heating values) for both post and oxy combustion based power plants is assumed to be 45%, while that for pre-combustion based power plants is assumed to be 50%. These efficiency numbers exclude the capture penalties and are based on a careful analysis of reported data. Rubin and Zhai [30] reported that net plant efficiency of between 42.3% and 53.1% (based on HHV (higher heating values) have been used in several studies for natural gas-fired power plants without capture. Strube and Manfrida [10] used an efficiency of 36.3% (based on HHV) for the pulverized coal power plant considered in their study. Li and Liang [13] assumed an efficiency of 42.7% (LHV-based) for a pulverized coal plant study. The United States EPA (Environmental Protection Agency) mentions that the average efficiency of fossil fuel power plants in the United States is 33% (www.epa.gov.sg). It was reported that one of the most efficient coal-fired power plant, located in Denmark, operates at a net efficiency of 47% (LHV-based) [31]. Power generation from hydrogen combustion is more efficient and hence we assume a slightly higher efficiency of 50% for pre-combustion processes. Using these assumptions, capture penalties associated with the various capture modes and for the different fuels are determined. These energy penalties are based on a power plant with 500 MW of net output. First, we take the energies from Table 1 (target energies for post and pre-combustion, and actual energies for oxy combustion); these are shown in Fig. 2 to clearly illustrate the comparison between the different fuel and capture-combustion types. These energies are then divided by the electricity generated per ton of CO_2 emitted for each fuel type to obtain the respective energy penalties shown in Fig. 3.

Fig. 2 demonstrates that the lowest capture energy per ton of CO_2 is obtained for coal-based power plants, and for all modes of power generation, followed by fuel oil and natural gas. However, the trend is very different for energy penalties, as seen from Fig. 3. Natural gas has the lowest energy penalty, followed by fuel oil and coal. This can be attributed to the high energy density of natural gas; CO_2 emissions per kWh are hence the lowest, and the electricity generated per ton of CO_2 the highest. This translates into lower energy penalties, even though the absolute capture energy is

Table 2
Actual minimum energies (kWh/ton CO_2) for carbon capture in vacuum swing adsorption and membrane permeation for different fuels.

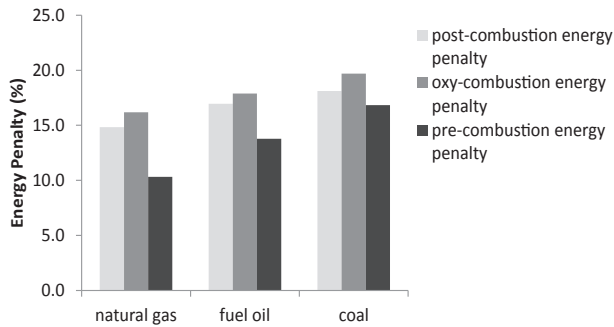| Fuel	Combustion type	Feed concentration (mol % CO_2)	Adsorption	Membrane permeation		Energy target Values computed in this work
				Cross flow model	Mixed flow model	E_{target} or $E_{target2}$
Natural gas	Post	3	568	682	2054	350
Fuel oil		8	228	289	629	270
Coal		15	134	152	333	220
Natural gas	Pre	25	90	95	196	176
Fuel oil		33	68	68	142	150
Coal		40	58	40	115	132

Fig. 3. Target energy penalties for different methods of CO$_2$ capture.

higher due to the low CO$_2$ concentration in the flue gas from a natural gas-fired plant. Comparing the various modes of power generation, pre-combustion has the lowest energy penalty, followed by post-combustion capture and oxy combustion, irrespective of the fuel type.

4. Conclusions

Capture energies and corresponding energy penalties have been compared for various scenarios: pre, post, and oxy combustion capture and for different fuel types: coal, natural gas and fuel oil. Separation energy estimates were based on the minimum thermodynamic separation work for the various separations. The analysis finds the lowest energy penalties for natural gas-based power plants, with pre-combustion capture as the best option. Therefore, this seems to be the best option for new power plants. For existing plants, the focus will be on oxy or post-combustion capture in order to avoid the extra capital costs associated with retrofitting for pre-combustion. Of the former two, post-combustion seems to be the more attractive option associated with lower energy penalties.

We have presented a high-level thermodynamic comparison of the energy penalty for CO$_2$ capture for different (general) fuel types and for different (generalized) combustion processes. This high-level analysis has the advantage of being general, comprehensive, and independent of the specific choice of separation technology. The use of a scaling factor based on industrial experience accounts for process and technology choices as well as impurities in the flue gas. Our study thus provides the baseline; detailed process simulations accounting for the separation technique, the process configuration, and the actual flue gas and fuel composition are a necessary next step to determine more realistic separation penalties, as well as OPEX (operating expenditure) and CAPEX (capital expenditure).

Acknowledgement

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