

TCCS - 6

Techno economic evaluation of amine based CO₂ capture: impact of CO₂ concentration and steam supply

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Abstract

The timing and selection of CO₂ sources will affect the cost of achieving projected CCS based emission reductions. Performed process simulations and cost estimations clearly point out the impact of CO₂ concentration and steam supply when capturing CO₂ from an atmospheric gas stream with MEA-based chemical absorption. An incremental increase in CO₂ concentration reduces both operating and investment costs, mainly due to lower energy consumption and reduced equipment capacity. Reduced investment costs dominate the sharp decline in net present value of costs when increasing CO₂ concentration from 2.5% to 10%, while a more moderate cost decline is present when going from 10% to 20% CO₂. The impact of steam cost is evident for all studied CO₂ concentrations. The cost sensitivity illustrate how important it is to understand the dynamics of cost components when selecting sources appropriate for CCS or struggle to improve performance of capture processes. This work contribute to highlight the relative importance of CO₂ concentration and steam supply, realizing that final selection of CO₂ source for CCS will involve addition decision variables.

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1. Introduction

CO₂ capture and storage (CCS) has the potential to significantly reduce man-made CO₂ emissions from large point sources, and is projected to provide 20% of the lowest-cost reductions in man-made GHG emissions in 2050 [1]. The timing and selection of CO₂ sources will affect the cost of achieving projected CCS based emission reductions. Among factors affecting the attractiveness of a particular CO₂ source for CCS, IPCC Special Report on CCS [2] highlight four; (I) CO₂ volume, (II) CO₂ concentration and partial pressure, (III) integrated system aspects and (IV) proximity to suitable reservoir.

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Understanding the relative importance of the concentration and partial pressure of CO₂ sources is not only relevant when assessing CCS feasibility of existing CO₂ sources, but also to provide support for future reengineering of CO₂ intensive industrial processes. Mapping of present large scale CO₂ sources shows great variations in CO₂ partial pressure. While atmospheric flue gas from gas turbines have a CO₂ partial pressure of 0.03-0.04 bar, high pressure natural gas entering gas processing plants might have a CO₂ partial pressure above 40 bar. The partial pressure is important in design and selection of appropriate CO₂ capture technology. Depending on the requirement of the processes, CO₂-containing gas streams such as process streams from ammonia and hydrogen production have already high CO₂ concentration (similar processes as pre-combustion), and simply require dehydration before CO₂ compression, transport, and storage. The majority of CO₂ sources are, however, emitting CO₂ containing gases at atmospheric pressure, accounting for over 80% of the total CO₂ emissions from large stationary sources emitting more than 0.1 Mt CO₂ per year [2]. Table 1 shows relevant properties of common CO₂ sources, indicating that the CO₂ concentration of sources at atmospheric pressure could vary in the range of 1 – 33 mol % [3].

Table 1: Overview of CO₂ properties for different industrial processes [2, Table 2.1 and Table 2.2]

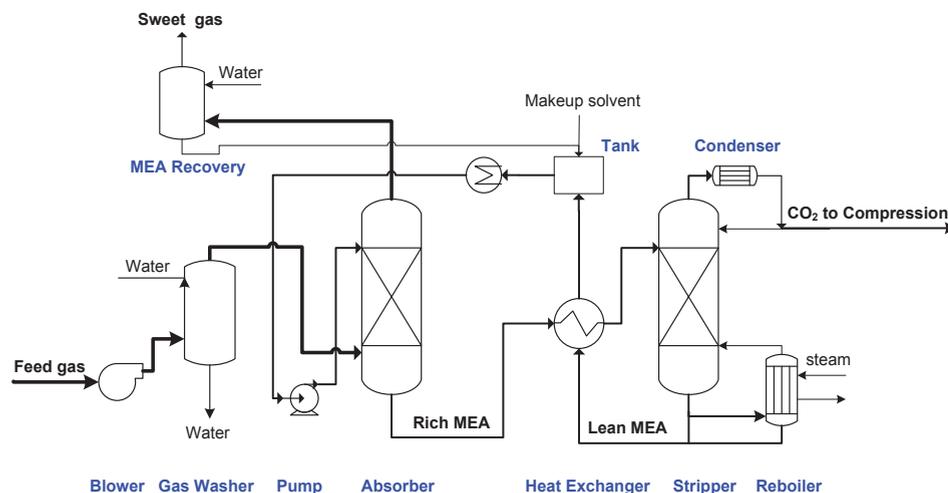
Industrial process	Gas pressure(bar)	CO ₂ concentration (mol%)	CO ₂ partial pressure (bar)
Aluminium Production	~1	1~2	0.01~0.02
Natural Gas Combined Cycle (NGCC)	~1	3~4	0.03~0.04
Conventional Coal fired Power Generation	~1	13~15	0.13~0.15
Cement Production	~1	14~33	0.14~0.33
Steel Production (blast furnace)	1~3	20~27	0.2~0.6
Hydrogen Production	22~27	15~20	3~5
Integrated Gasification Combined Cycle	20~70	8~20	1.6~14
Natural Gas Processing	9~80	2~65	0.5~44

In this paper we focus on amine-based CO₂ capture, mainly Monoethanolamine (MEA) aqueous solvent which is relatively mature and suitable for atmospheric CO₂ containing gases over a wide range of CO₂ concentrations. In order to gain more insight to the capture process with varying CO₂ concentrations, a model-based method is applied in this work to simulate the whole capture and regeneration process for different CO₂ concentration gases. This is performed with Aspen Plus[®] software which has previously been proven to be a useful tool for simulating CO₂ capture process [4;5]. Based on the results of the simulation, the mass and energy balance of the total process, information of detailed streams and units, energy consumption of each unit, as well as the equipment size of each main unit are obtained. This information is the basis for the calculation of the economic data and analysis of the economic performance. In addition to analysing the impact of CO₂ concentration, different steam supply alternatives are analysed to compare the impact on the capture costs for CO₂-containing gases at atmospheric pressure using MEA technology. It should be emphasized that for this comparative study, subsequent CO₂ compression, transport, and storage are not included. These processes are considered independent of studied feed gas properties going into the defined capture process.

2. Process simulation

The details of the mechanisms of CO₂ absorption into an amine solution in an absorption column are quite complex. There are many references about the chemical reactions involved in the process, and the

technology has been described in many papers[6;7]. For this typical electrolyte thermodynamic system, the amines property package in Aspen Plus[®] is used to model the absorption and desorption processes. For the unit models, the RadFrac² model framework is used for both the absorber and the stripper. The absorber is a simple RadFrac column, whereas the stripper column has a condenser at the top and a reboiler at the bottom. Considering the low efficiency of the gas absorber column (typically Murphree efficiency³ can be set as 10~30%), the absorber is modeled using RadFrac with equilibrium stages with a Murphree efficiency of 27%. The equilibrium stage number can be estimated depending on the required CO₂ capture ratio, 90% in this work. The real stage number and the height of packed bed can be estimated based on the total column efficiency and property of the selected packing material. The diameter of the column is estimated based on the column loading, transportation properties and packing characteristics. Table 1 shows a diagram of CO₂ capture with MEA solvent that was used to model the system.



<i>Cooling water: 15°C, 1.113 bar</i>	<i>Lean solvent: MEA 28.3%(wt), 40°C, 1.113 bar</i>
<i>CO₂ capture ratio: ~90%</i>	<i>Stripper: theoretic stage number: 15, top: 70~90°C, 1.8 bar, bottom: 110~125°C</i>
<i>CO₂ Condenser: 40°C, 1.8 bar</i>	<i>CO₂ absorption: theoretic stage number: 10</i>
<i>Murphree efficiency: 27%</i>	<i>Blower: efficiency: 0.72, from 1.01 to 1.113 bar</i>

Figure 1: Typical absorption and desorbing process for CO₂ removal with MEA technology

The system boundaries do not include the CO₂ emitting process itself, only the resulting CO₂-containing feed gas (process stream or flue gas). The CO₂-containing feed gas from an unidentified industrial source is pressurized using blowers before it enters the absorber in order to overcome a substantial pressure drop as passing through a tall absorber column. Then it is cooled down by water washing and treated for removing contaminants, such as particles, tar, dust etc. The cleaned gas then contacts the MEA aqueous solvent in a counter-current, packed absorber, after which the purified gas leaves the top of the absorber along with some traces of MEA, thus water washing is needed to further recover it. The rich solvent is removed from the bottom of the absorber and enters a hot-cold exchanger to be preheated (to 100-110°C) by the regenerated lean solvent, before being regenerated in the stripper. The CO₂ is stripped from the top

² Radfrac is a rigorous tray to tray model for simulating multistage liquid-vapor fractionation equilibrium.

³ Murphree efficiency represents the deviance of the system compare to the ideal separation equilibrium.

of the stripper and dried. The dry CO₂ (>98.5%) is sent to a CO₂ compressor to reach the pressure required by transportation and storage. Detailed process description can be found in the literature [4;6].

Seven specified CO₂ concentration and resulting CO₂ containing gas flow rates are studied, presented in Table 2.

Table 2: Selected feed gas compositions [100°C, 1.01 bar]

CO ₂ concentration	2.5%	5%	8%	10.5%	13.5%	17%	20.5%
Feed gas flow rate [NMm ³ /hr]	7.59	3.43	2.47	1.87	1.45	1.14	0.93

2.1. Process simulation results

For the CO₂ capture process, the key input parameters are composition and flow rate of the CO₂-containing feed gas, absorption temperature and pressure, composition and property of the solvent, regeneration pressure, and the configurations and parameters of the absorber and stripper. The performances of the absorption and regeneration are expressed by CO₂ capture ratio, solvent flow rate, heat duty of reboiler, and the thermodynamic properties of the absorber and stripper. In this work, we assume that the lean loading of solvent and the CO₂ capture ratio are constant, thus the flow rate of the solvent for different CO₂ concentrations is calculated depending on the capture requirement and the column parameters. Since to the CO₂ partial pressure of the sweet gas emitted from the top of the absorber increases with the CO₂ concentration at a fixed CO₂ capture ratio, the required solvent flow rate decreases correspondingly based on the vapor-liquid equilibrium principle and mass balance. Simulations show that the loading of the rich solvent in the bottom of the absorber increases with the increasing of the CO₂ concentrations from roughly 0.41–0.49 mol CO₂/mol MEA.

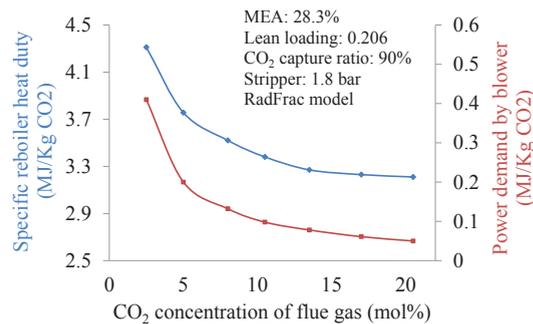


Figure 2: Energy consumption of stripper and gas blowers

Figure 2 shows the energy consumption of the stripper (blue curve) and gas blowers (red curve) for different CO₂ concentrations at atmospheric pressure. The specific reboiler heat duty decreases exponentially when increasing the CO₂ concentration, leveling off when the concentration reaches about 15%. The same trend is present in the blue curve for the gas blower, with larger volumes of non CO₂ gas being pressurized for low concentration streams. It is thus clear that high CO₂ concentration streams consume less energy per unit of CO₂ captured. It is well known that the high energy consumption for amine-based CO₂ capture is mainly caused by solvent regeneration in the solvent stripper. The simulation results show that in a stripper, one of the reasons for high energy demand is that a lot of water is stripped out when CO₂ is released from the liquid phase. The water refluxes back to the stripper as condensed water with a lower temperature. During this process, a significant amount of energy is lost. Furthermore,

simulation results show that for lower CO₂ concentrations, more water will be heated, vaporized, and is refluxed back in the stripper. More specifically we see that 1900 kmol/hr condensed water refluxes back to the stripper when the CO₂ concentration is 8%, while only 950 kmol/hr condensed water refluxes for the case of 17% CO₂ concentration.

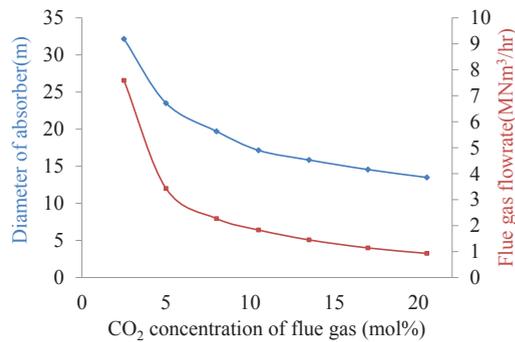


Figure 3: Estimated diameter and gas flow rate of the absorbers

The variation in the required load for reboiler and gas blowers will affect the required equipment capacity and resulting equipment costs. The simulation also shows that the operational loading in the absorber increases with the decreasing of CO₂ concentration. Figure 3 show how the absorber diameter for lower CO₂ concentrations is larger than of higher CO₂ concentration.

3. Cost evaluation methodology

3.1. Investment costs

A factor estimation method is used in order to estimate investment costs of the CO₂ capture plant where the estimated equipment costs are multiplied with direct⁴ and indirect⁵ cost factors to obtain the investment costs. Equipment costs and direct costs of carbon steel equipment are estimated using Aspen Process Economic Analyzer[®], based on results from the process simulations in Aspen Plus[®]. Direct costs of components in carbon steel are adjusted to reflect the cost of applied stainless steel. This is adjusted by multiplying direct costs with a material factor of 1.3 for machined equipment (pumps and blowers) and 1.75 for welded equipment (columns and heat exchangers)[8]. The investment cost for given equipment is then calculated by multiplying the component specific direct cost with the appropriate indirect cost factor (see Table 3):

Table 3: Indirect Cost factor as function of Direct Cost[8]

Total Direct Cost lower limit (k€)	0	15	51	211	367	624	1,428	> 3,620
Total Direct Cost higher limit (k€)	15	51	211	367	624	1,428	3,620	
Indirect Cost Factor	2.23	1.86	1.71	1.65	1.63	1.59	1.58	1.50

The total investment cost is then determined by summarizing the estimated investment cost for all components within defined system boundaries.

⁴ Includes erection, piping, secondary equipment, civil work, insulation, steel and concrete costs.

⁵ Includes engineering, administration, commissioning and contingencies costs.

3.2. Operating costs

The operating costs are split into fixed and variable operating costs. The fixed operating cost depends on the investment cost and covers maintenance, insurance, and labour costs. The variable operating cost, being a function of the amount of CO₂ captured, covers consumption of utilities, electricity, steam, cooling water, and MEA make up. The annual fixed operating cost is assumed to be 7% of total investment costs, while the annual variable operating costs are estimated using the utilities consumptions given by process simulations and utility costs given in Table 4.

Table 4: Utility costs

Utilities	Costs
Electricity[9] (€/MWh)	55
Natural Gas[9] (€/MWh)	23
Water[10] (€/m ³)	0.02
Pure MEA[4] (€/t)	1300

The steam required to release CO₂ from the solvent can be supplied from various sources. Depending on the heat and energy sources available, steam can be produced using electrical or fired boilers (e.g. natural gas), or by extracting/recovering heat from industrial processes. The cost of producing steam from electricity or a fired boiler is directly linked to energy commodity prices and steam production efficiency.

$$\text{Steam cost (€/kWh)} = \frac{\text{Energy Commodity Price (€/kWh)}}{\text{Steam Production Efficiency (\%)}}$$

Integration of CO₂ capture on power plants typically implies extraction of steam prior to the low pressure steam circuit. The steam cost can then be estimated based on the lost electricity production.

$$\text{Steam cost (€/kWh)} = \text{Steam Quality (\%)} \times \text{Electricity price (€/kWh)}$$

The steam quality is here defined as the percentage of the steam energy being transferable to electricity. In cases where waste heat is recovered the steam quality is defined as zero (no alternative use). This is clearly a desirable situation for a CO₂ capture process, where steam for the stripping process is free. Steam costs as function of the different steam supply alternatives are shown in Table 5.

Table 5: Steam costs as function of heat source

Steam source	Steam production efficiency (%)	Steam Quality (%)	Steam cost (€/GJ)
Electricity boiler	99 ⁶		15.6
Natural Gas boiler	81.7[11]		8.0
Steam prior to LP turbine (5bar, 150°C) [12]		23[13]	3.5
Steam from waste heat		0	0

⁶ The production of steam using electricity is very close to 100% and often considers being a bit lower to take into account the heat losses.

The investment cost and emissions associated with each steam supply alternative is not included in this report. In the base case cost evaluation steam is extracted prior to the low pressure steam circuit. Alternative ways of producing steam are studied in subsequent sensitivity analysis in section 4.2.

3.3. Key Performance Indicator

As the amount of CO₂ captured is the same for all cases (2 MtCO₂/y), the net present value of project costs (NPV) is used as the key indicator to compare the cost of capture for different CO₂ concentrations. The NPV is equal to the sum of discounted cost flows during the project lifetime. The NPVs are estimated assuming a real discount rate of 8% and an economic lifetime of 25 years [4; 14].

4. Cost evaluation results

4.1. Base Case Results: Extracting steam prior to LP turbine

Figure 4 clearly shows that capturing CO₂ from CO₂-containing gases at atmospheric pressure increases exponentially as the CO₂ concentration drops. Performed process and cost simulations show that an increase in CO₂ concentration from 2.5% to 20.5% reduces the NPV of costs by approximately fifty per cent. Two thirds of this decrease is due to reduced investment costs and fixed operating costs (proportional to investment cost). Hence the relative share of variable operating costs increase with an increase in CO₂ concentration.

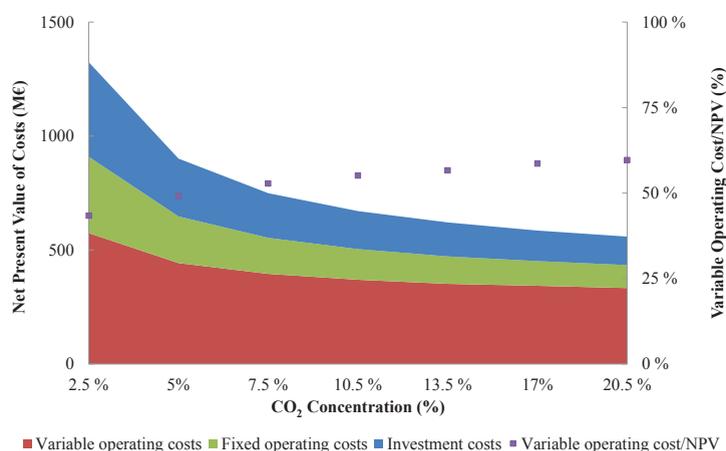


Figure 4: Capture costs as function of CO₂ concentration

Figure 5 presents the investment cost breakdown, where main components directly affected by feed gas flow rate (washing column, absorption column, MEA recovery column and blowers) show high sensitivity to CO₂ concentration. For the chosen capacity of 2 MtCO₂/y captured, between 50 and 65% of investment cost are allocated to the packing material and steel used for the four columns of the capture process (flue gas washing column, absorption column, MEA recovery column, and stripping column).

The annual operating costs in Figure 6 also show a non-linear drop as the CO₂ concentration increases. This is dominated by a reduced fixed operating cost, derived from the investment cost profile. The variable operating cost components experience a more marginal decrease, due to reduced feed gas compression and lower stripping energy penalty for higher CO₂ concentrations. The difference in cost structure influences the relative importance of potential cost reductions efforts on total capture cost. A

source with a CO₂ concentration of 2.5% would require over a 20% reduction in steam consumption to achieve similar reduction in total capture cost as by reducing investment cost by only 10%. For higher concentration sources the relative importance of steam consumption increases, whereas for a source with CO₂ concentration of 20.5% a 10% reduction in investment cost is equivalent to 8% reduction in steam consumption. Using solvent with higher MEA concentration can potentially lower the energy consumption by reducing the amount of water vaporized though may cause more serious material corrosion and degradation of the solvent. A fair judgement of such improvement measures requires an assessment of how individual cost elements affect the total net present value of costs, including both investment and operating costs.

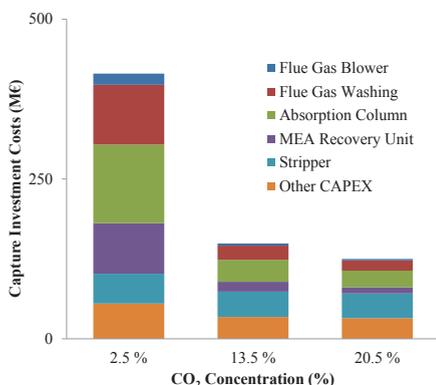


Figure 5: Investment costs

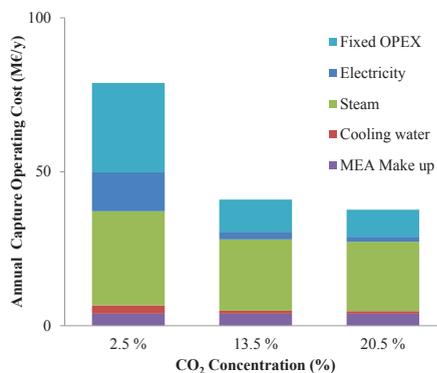


Figure 6: Operating costs

The observed drop in the cost of capture is clearly a motivation to select sources with high CO₂ concentration, given that everything else is equal. This is reflected in efforts to increase CO₂ concentration in low concentration sources. Exhaust gas recirculation (EGR) has been studied for gas fired power plants [14], enabling increase of CO₂ concentration from 3.9% to 7.8% and thereby reducing the net energy consumption of the capture process (the net efficiency of the power plant with capture was improved). In addition, simulations in this work indicate a reduction in investment cost (and fixed operating cost) of over 30% when moving from 3.9% to 7.8% CO₂ concentration.

4.2. Sensitivity analysis on the steam source

Figure 7 illustrate the relative importance of CO₂ concentration and available steam supply alternative for an atmospheric flow of CO₂ containing gas. The rating of the steam supply alternatives reflects the steam costs in Table 5. In absolute terms the gaps between steam supply curves are relatively stable for the entire CO₂ concentration range modelled, reflecting minor changes in steam consumption illustrated in Figure 6. The availability of steam for solvent regeneration will depend on location and the industrial process; see illustrative circles in Figure 7. Coal- and gas-fired power plants normally have access to sufficient low pressure steam suitable for CO₂ capture while other industrial sources might need external supply of steam. It is important to note that certain CO₂ sources might have the possibility to combine steam supply alternatives, placing them somewhere between the identified steam supply alternatives (curves) in Figure 7. Estimations show that low concentration sources of 3–4% CO₂ with integrated steam supply (e.g. gas-fired power plant) is considered as costly as high concentration source of 20% CO₂ (e.g. cement) using natural gas boilers to produce steam for solvent regeneration. The relative attractiveness of coal-fired power plants among CO₂ sources at atmospheric pressure is confirmed, emphasizing that

characteristics not included in this work could affect this; CO₂ volumes, flow profile, impurities, available space, distance to storage etc.

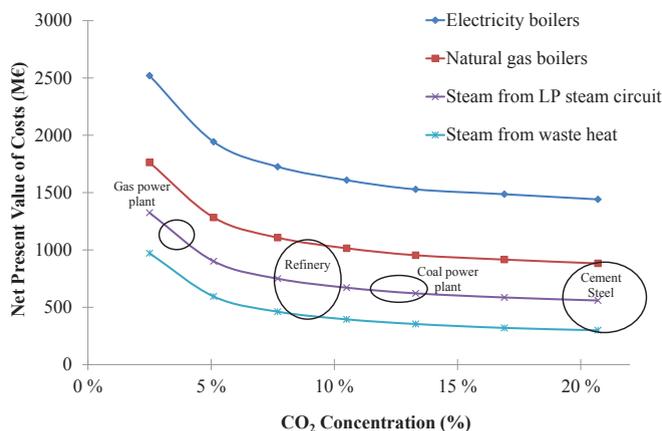


Figure 7: Capture costs as a function of the CO₂ concentration and steam source

5. Conclusion and Discussion

Simulation and cost estimations performed in this work clearly point out the impact of CO₂ concentration and steam supply when capturing CO₂ from an atmospheric gas stream with MEA-based chemical absorption. An incremental increase in CO₂ concentration reduces both operating and investment cost, mainly due to lower energy consumption and reduced equipment capacity. Reduced investment cost dominates the sharp decline in present value of costs when moving from 2.5% to 10% CO₂ concentration, while a more moderate cost decline is present moving from 10% to 20% CO₂ concentration. The impact of steam cost is evident for all studied CO₂ concentrations. As an example the cost reduction achieved by utilizing waste heat instead of generating steam from gas fired boilers are in the same order of magnitude as moving from a source with 2.5% CO₂ concentration to one with CO₂ concentration of 20%. The cost sensitivity illustrates how important it is to understand the dynamics of cost components when selecting sources appropriate for CCS or struggle to improve performance of capture processes. This work contributes to highlight the relative importance of CO₂ concentration and steam supply, realizing that final selection of CO₂ source for CCS will involve additional decision variables.

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