TECHNOLOGY FACTSHEET

Retrofit of post-combustion CO2 capture for refineries using MEA solvents

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Sector	CCS
	Refineries
ETS / Non-ETS	ETS
Type of Technology	CCS
Description	There are a variety of techniques for post-combustion carbon capture that can be applied to flue gases; this factsheet considers chemical absorption with monoethanolamine (MEA) solvents. Post-combustion capture does not require any major modifications to the refining process; MEA amine stripping technology is an end-of-pipe technology added to the plant to capture CO2 from existing flue gas streams. The modifications required for CO2 capture are cleaner flue gas (dust filters, NOx removal, additional desulphurisation equipment, etc.); a CO2 capture unit (absorber and stripper columns, heat exchangers, condensers, and a reboiler); and a CO2 compression and dehydration unit. However, the design of the site plays an important role in the cost and feasibility of implementing post-combustion CO2 capture. There are many different flue gas streams on a typical refinery site, and how they are combined in different stacks can vary. Thus the CO2 concentration and flue gas volume per stack will vary in each site as well. As the capture process requires electricity (notably for compression) and steam (mainly for solvent recovery), additional investments are also required to expand the site's utilities. Many refineries have significant excess heat availability, which could reduce the cost and additional energy demand, but the potential to use that heat depends largely on site design and site-specific constraints, so has not been considered in this factsheet. This factsheet is based on literature looking both at hypothetical refinery site configurations and at specific sites. The cleaned flue gas enters the absorber and is brought into contact with the MEA amine solution. About 90% of the CO2 is absorbed into the amine solution (now together referred to as a rich loading solution), and is then pumped to the stripper. In the stripper column, the rich loading solvent is heated with steam from the reboiler (which uses a heat exchanger to transfer heat from external steam to a heat transfer fluid), breaking the chemical bonds between the amine solvent and the CO2, and causing it to release its CO2, creating a relatively pure CO2 stream. The remaining solution (called a lean loading solution), now at a temperature of about 120 degrees C, is pumped back to the absorber to begin the cycle again, first passing through a heat exchanger to preheat the rich loading solution. The CO2 continues to the compressor, which compresses the gas for transport and storage. Pressure in the CO2 pipeline can vary significantly (both liquid and gaseous transport is possible) and has an important impact on total investment cost, operating cost and electricity use. This factsheet considers transport at about 110 bar/11 MPa to 140 bar/14 MPa. While the MEA solvent capture technique is can also be applied to flue gases from power plants, there are two major differences when considering a refinery applications. First, the installations require combination of multiple flue gas streams (from various processes and utilities), which leads to higher equipment costs per unit of captured CO2. Second, the final concentration of CO2 in the flue gases is higher than those of a typical gas-fired power plant (here the refinery concentration is assumed to be around 9%vol, though this is highly dependent on the configuration, where a typical gas-fired power plant may have a concentration in the range of 5-10%vol). Post-combustion carbon capture can be either retrofitted or designed in a greenfield refinery; this factsheet considers a retrofit to an existing refinery. Integrated design could lead to lower costs or higher efficiency. Refinery configurations in the Netherlands vary widely. Key flue gas streams come from utilities (boilers and/or CHPs), steam methane reformers (SMR), fluid catalytic crackers (FCC), distillation processes (atmospheric and/or vacuum). Not all processes are present at all refineries, and thus their shares in the total CO2 emissions of the refinery also vary. Capture from the SMR unit of a refinery can also be considered separately; capture of CO2 from an SMR only is covered by other factsheets. This factsheet considers several configurations, with capture of CO2 from flue gases from utilities, SMR, FCC, and distillation processes or some subset of those processes. The assumed CO2 concentration in these flue gases is about: utilities ~8%vol, SMR ~24%vol, FCC ~17%vol, atmospheric/vacuum distillation ~11%vol. The average concentration of the flue gas entering the capture unit for these configurations ranges from 6.7%vol to 13.1%vol, with an average of about 9%vol. At lower concentrations, the cost per tonne of captured CO2 rises. The power plant flue gases have slightly lower concentrations than the other sources shown here but typically account for the largest single source of CO2 emissions at a refinery, and therefore are often included in studies of CO2 capture at refineries. (Roussanaly et al., 2017; Ho et al., 2011; Leeson et al., 2014). Furthermore, an average MEA loss of 2 kton/ Mton CO2 is assumed. Based on different cases, losses of MEA may increase due to thermal, oxidative degradation or larger presence of contaminants such as SOx and NOx. These consideration are case specific and left out of scope.
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	Post-combustion carbon capture has been demonstrated at full scale in a refinery, and operates commercially using the same capture technique in power plants. Every refinery configuration is different, so the specific design and costs will vary, but the basic principle of chemical absorption carbon capture using MEA solvents remains the same. Geological storage of carbon dioxide has also been demonstrated and is commercially available, though there are currently no CCS projects operating in the Netherlands. The Porthos project, which will transport CO2 captured in the port of Rotterdam by pipeline, for storage in retired gas fields in the North Sea, has signed Joint Development Agreements with ExxonMobil and Shell, both of whom operate refineries in the Rotterdam area. Air Liquide and Air Products have also signed Joint Development Agreements. The partners will apply for SDE++ funding for the project. Construction, according to the project timeline, will begin in 2022, and operation will begin in 2024.

TECHNICAL DIMENSIONS											
	Functional Unit		Value and Range								
Capacity	Mton CO2 captured		1,60								
			0,50			-			2,80		
Potential			Current			2030			2050		
			-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
Market share		%	-			-			-		
			-	–	-	Min	–	Max	Min	–	Max
Capacity utlization factor	1,00										
Full-load running hours per year											
Unit of Activity	Mton CO2 captured/year										
Technical lifetime (years)	25,00										
Progress ratio											
Hourly profile											
Explanation	Capacity varies depending on refinery size, configuration, process equipment and utilities. Each of the refineries in the Netherlands has a different configuration and different processes on-site; thus this factsheet is not equally applicable to all Dutch refineries. The total refining nameplate capacity of the Netherlands is about 67 Mt crude oil intake/year, with 6 refineries ranging from 3.5 Mt/year to 21 Mt/year. More information about Dutch refinery capacity can be found in the MIDDEN report (Oliveira and Schure, 2020). This factsheet is most relevant for a refinery of medium to high complexity with capacity of 220 000 bbl/day throughput or higher, with capture of CO2 from at least three point sources on site. It is not possible to determine the potential or market share of this technology in the future, as it will be highly dependent on policy, subsidies, and CO2 prices, as well as the future of the Dutch refining sector. Utilization factor will likely be similar to the utilization factor of the refinery process equipment. No estimates were available on progress ratio or hourly profile.										

COSTS										
Year of Euro	2015									
	Euro per Functional Unit	Current			2030			2050		
Investment costs	mln. € / Mton CO2 captured	270,00			-			-		
		257,00	–	300,00	Min	–	Max	Min	–	Max
Other costs per year	mln. € / Mton CO2 captured	-			-			-		
		Min	–	Max	Min	–	Max	Min	–	Max
Fixed operational costs per year (excl. fuel costs)	mln. € / Mton CO2 captured	12,09			-			-		
		10,23	–	14,06	Min	–	Max	Min	–	Max
Variable costs per year	mln. € / MtCO2 captured	4,96			-			-		
		4,96	–	4,96	Min	–	Max	Min	–	Max

Costs explanation

The costs of capture can vary depending on the complexity and configuration of the refinery considered, cost of capital, and other company, sector, and site-specific parameters. Costs vary significantly based on the layout and configuration of a refinery and processes on site. A key factor is whether it is possible to combine flue gas streams into one stack where capture can be applied. (Leeson et al., 2017). Above, a range of estimates are presented representing different configurations that are relevant for Dutch refineries. Interconnection costs can make up a large share of the total investment costs (about 20-30% according to Roussanaly et al., 2017). Note that utility investment costs can also be an important share of the total investment costs (in the case of Roussanaly et al., 2017; around 20% for an additional natural gas CHP on site); costs for utilities are excluded from the investment costs given above. Variable costs include chemicals and catalysts, process water, and waste disposal. (Roussanaly et al. 2017).

Cost estimates are often presented on an annualized basis, per tonne of CO2 captured or avoided, including fixed and variable O&M costs. These costs are not directly comparable to the investment costs presented above, which are overnight capital investments per unit of capacity. Note that cost per tonne of CO2 captured differs from the cost per tonne of CO2 avoided (which takes into account the energy penalty - CO2 emitted in generating the additional energy needed for capture and compression of CO2 - and is therefore higher). For example, for medium-to-high complexity refineries, estimates range from $90 to 120 per tonne of CO2 captured (about 88-116 EUR 2015) (van Straelen et al., 2010) to $160 to 180 per tonne of CO2 avoided (about 139-156 EUR 2015) (Roussanaly et al., 2017; Gale, 2017). Another study of post-combustion CO2 capture in oil refineries in Australia finds a cost of about $87/t CO2 captured (about 83 EUR 2015) (Ho et al., 2011); however, this study considers captured only from the combined flue gas of the process heaters. This flue gas has a lower overall concentration of CO2 (~8%) than what is considered in the other studies, and also requires different on-site infrastructure (piping, ducts, etc.) than a case which also includes capture from the power plant, SMR, and FCC units. In all of these cases, the costs are considered over the lifetime of the project.

ENERGY IN- AND OUTPUTS											
	Energy carrier	Unit	Current			2030			2050		
Energy carriers (per unit of main output)	*Main output:* Steam	PJ	3,68			-			-		
			3,30	–	4,40	Min	–	Max	Min	–	Max
	Electricity	PJ	0,61			-			-		
			0,45	–	0,62	Min	–	Max	Min	–	Max
		PJ	-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
		PJ	-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max

Energy in- and Outputs explanation

Many refineries have on-site utilities (boilers and/or CHP units) to meet their process steam demand. Steam is generated using both natural gas and excess process gases. The additional steam demand for CO2 capture can be met by on-site utilities or can be purchased from an off-site steam generator. CAPEX considered above, from Roussanaly et al. (2017) and Gale (2017), excludes the cost of expansion of utilities to meet the additional steam demand for CO2 capture. Some sites may already have sufficient steam generation capacity on-site to meet the extra demand; in this case, additional fuel will be consumed. Steam demand is shown here, rather than fuel, to provide a generic case relevant to most refineries.

Note that most of the electricity demand is related to compression of CO2. This depends highly on the required pressure for CO2 transport, and thus is highly site- and project-dependent. A range is presented here, with low range estimates representing lower transport pressures (~20bar) and higher electricity demand representing higher pressures (~110bar).

MATERIAL FLOWS (OPTIONAL)											
	Material	Unit	Current			2030			2050		
Material flows	MEA solvent (make-up)	kt	2,09			-			-		
			2,09	–	2,09	Min	–	Max	Min	–	Max
			-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
Material flows explanation											

EMISSIONS (Non-fuel/energy-related emissions or emissions reductions (e.g. CCS)											
	Substance	Unit	Current			2030			2050		
Emissions	CO2 captured	Mton CO2-eq	-1,00			-			-		
			-1,00	–	-1,00	Min	–	Max	Min	–	Max
			-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
			-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max
			-			-			-		
			Min	–	Max	Min	–	Max	Min	–	Max

Emissions explanation

There is a wide range of emitted CO2 in these refineries. The variety of configurations considered have different total baseline CO2 emissions, as well as different shares of avoided and captured emissions, based on the different point sources of CO2 where capture techniques are applied. For the remaining emissions, the main value (0.38t CO2 emitted) represents cases where capture is applied on utilities, FCC, SMR, and distillation units at a medium- or high-complexity refinery. The high end of the range (1.82 tCO2 emitted) represents a configuration where capture is applied on FCC and distillation units, but not utilities, at a medium-complexity refinery. The CO2 capture rate that is achievable using MEA solvents on a single stream of CO2 (85-90%), is not achievable for the whole refinery, as there are small CO2 sources on site which are not suitable for capture; this means that the overall capture rate for a refinery is lower, depending on the particular configuration. (Roussanaly et al., 2017) (Ornaheim et al 2015). Overall capture rates for the data presented in this factsheet range from about 35% to about 75%, including CO2 from on-site utilities.

OTHER										
Parameter	Unit	Current			2030			2050		
		-			-			-		
		Min	–	Max	Min	–	Max	Min	–	Max
		-			-			-		
		Min	–	Max	Min	–	Max	Min	–	Max
		-			-			-		
		Min	–	Max	Min	–	Max	Min	–	Max
		-			-			-		
		Min	–	Max	Min	–	Max	Min	–	Max
Explanation										

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