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Air Quality Implications of Post Combustion Capture in Industrial Processes

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IEAGHG

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Leading the way to net zero with advanced CCS research. IEAGHG are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

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This report describes work undertaken by Imperial Consultants on behalf of IEAGHG. The principal researchers were:

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To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was Abdul'Aziz A. Aliyu.

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IEAGHG

Report Overview:

Air Quality Implications of Post Combustion CO_2 Capture in Industrial Processes

Introduction

Retrofitting existing emission sources with carbon capture systems can alter the emission profile. Emissions of some pollutants[1] may decrease, others may increase, and new substances could be introduced into the environment.[2] Established permitting frameworks, measurement techniques, and emission control approaches in other industrial contexts provide a basis for regulatory assessment of post combustion CO_2 capture (PCC) in industrial processes*.

Previous comprehensive literature reviews on the impact of carbon capture and storage (CCS) deployment on air quality have primarily focused on the coal and natural gas power industries or have not addressed the impacts on co-pollutants (SEPA, 2015; Buvik *et al.*,

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[1] Such as sulphur dioxide, nitrous oxides, and particulate matter.
[2] Pollutants other than CO_2 are referred to as "co-pollutants".
*For context, SOx and NOx abatement is already required for power and heavy industry in most Organisation for Economic Co operation and Development (OECD) countries, and in some non OECD countries such as China, through permitting and air quality regulation, for example BAT based permitting in Europe and Clean Air Act requirements in the United States, often implemented via *feed and* flue gas desulphurisation for SOx and combustion control measures (flue-gas recirculation, low-NOx burner designs, and combustion tuning) selective catalytic reduction *and/or selective non-catalytic reduction* for NOx.

2021; Gibbins, Lucquiaud and Samson, 2024; Rochelle, 2024)[3]. The industrial sector is a significant contributor to global greenhouse gas emissions, contributing around 25 % (GCCSI, 2016), with key industries such as cement, iron and steel, and refining being responsible for a broad spectrum of pollutants beyond carbon dioxide (CO_2).

Therefore, there is a clear need for a comprehensive study such as this one. Imperial Consultants were commissioned to undertake this work, which assesses the air pollutant implications of CCS retrofit in heavy industry by comparing baseline emissions from representative host facilities in the cement, iron and steel, and refining sectors prior to capture with emissions expected following CCS integration. A gap analysis was also conducted to identify research areas that are currently underexplored, and the study investigates potential synergies between existing air quality control technologies and CCS systems.

Key Messages

- While CCS is primarily deployed to capture (and store) CO_2 emissions, it can also deliver important co-benefits. Studies suggest that reductions in NO_x, SO_2 and $PM_{2.5}$ associated with CCS can improve material public health benefits, which may improve the overall societal value of CCS deployment, although outcomes and the extent of any health-related savings are site specific.
- Severe health effects associated with SO_x and NO_x often arise from their atmospheric conversion into secondary PM2.5 and from ozone formation. Regulatory frameworks generally emphasise controlling these precursors through the use of best available technologies (BATs).
    - Solvent developers are creating formulations and mitigation methods that tolerate higher concentrations of co-pollutants absorbed into or interacting with the solvent during capture, which can influence the extent of upstream flue gas cleaning required and the potential for solvent-related emissions. However, the specific tolerance limits remain proprietary and are not disclosed to the academic community.
- The role of the amine unit in PM control is context dependent. When stringent upstream PM controls are not in place, the amine unit functions as a PM removal device. Conversely, with highly effective upstream controls, the effect of condensable PM (CPM) formation may dominate. Even without upstream controls,

[3] The authors are unaware of existing literature reviews examining the impact of CCS deployment in industries and projects that combust biomass or materials with high biogenic content, such as waste-to-energy (WtE) and bioenergy with carbon capture and storage (BECCS). This report does not specifically address biomass combustion. However, studies in this field were included when relevant for context.

CPM formation is still possible but is overshadowed by overall filterable PM (FPM) removal.

- NO_2 is the primary reactive NO_x species in amine systems, absorbed mainly through hydrogen abstraction to form amine radicals and nitrite. NO shows little reactivity with monoethanolamine (MEA), although amine radicals can react directly with NO to form nitrosamines, a route that is generally minor in overall NO_x reactions with amines.
- SO_2 is readily absorbed by amine solvents, forming heat-stable salts (HSS) that do not degrade under normal operating temperatures. Operators typically rely on upstream flue gas desulfurisation (FGD) to prevent HSS build-up, as solvent reclamation is energy intensive. This ensures SO_2 concentrations in the absorber outlet gas exiting the amine units are usually below 1 ppmv.
- Nitrosamines (NSAs) and nitramines (NAs) attract significant regulatory and research attention, given their carcinogenic and mutagenic potential because detected levels are often at or near instrument detection limits.
    - In plume modelling, interactions with emissions from nearby stacks are important, particularly in industrial clusters where NO_2 from secondary sources can react with amine emissions, potentially compounding impacts at downwind receptors.
    - Permit approval for CCS plants is typically contingent upon robust modelling demonstrating that predicted ground-level concentrations of these compounds remain below regulatory thresholds.
- Air quality assessments of CCS in industry should also consider indirect co-pollutant emissions from added energy use, as well as liquid and solid waste streams.
    - While CO_2-side waste streams are generally smaller in volume and lower in contaminant concentration than flue-gas-side streams, they should not be assumed to pose negligible environmental risk. For instance, a short vent stack on the TEG regenerator could lead to localised ground-level impacts if amines or other volatile contaminants are present.
    - Solid waste streams are less documented, with the only reference found in the 2015 Scottish Environment Protection Agency (SEPA) review.[4]

[4] SEPA (2015) *Review of amine emissions from carbon capture systems*. Scottish Environment Protection Agency. Available at: https://www.sepa.org.uk/media/141046/review_of_amine_emissions_from_carbon_capture_systems.pdf (Accessed: February 19, 2025).

- Air quality implications and health co-benefits of post-combustion capture in industry are site- and technology-dependent. Implications are typically influenced by plant type, age, capture media, baseline emission controls, fuel characteristics, and proximity to population centres, with newer facilities or those already upgraded to BAT controls showing smaller incremental improvements relative to older, higher-emitting plants.
- Evidence base is still emerging. While studies indicate that amine CCS in heavy industry can deliver reductions in SO_2 and PM and generate large health benefits (marked reductions in population health burden within the local exposure catchment area), methodological uncertainties mean findings should be seen as indicative rather than definitive. Robust, site-specific analysis is needed to underpin reliable health and environmental assessments.
    - Typical continuous emission monitoring systems report a single NOx value as NO_2 equivalent and are optimised for total NOx compliance, rather than robust NO and NO_2 speciation. Inventory reporting therefore, often relies on assumed or default NO and NO_2 splits.
        - This matters because nitrosamine formation depends on NOx speciation and nitrosating chemistry, so the NO and NO_2 balance can materially influence impact assessments. Assumptions that were previously acceptable for compliance purposes may no longer be adequate for assessing nitrosamine risk.
    - SO_3 is generally not included in emission inventories, despite its strong influence on amine aerosol formation and solvent loss. Available SO_3 measurements are limited to a small number of pilot or site-specific studies, creating uncertainty around typical levels and variability across the industry.
- There is a notable lack of publicly available data on air quality implications of PCC in heavy industries such as cement, steel & iron production.
    - To bridge these knowledge gaps, ongoing research projects, such as AURORA[5], will provide valuable data to the research community. Furthermore, the U.S. Department of Energy (DOE) is deploying a mobile emissions testing unit and funding front-end engineering design (FEED) studies as well as pilot plant studies for PCC deployment in cement plants

[5] About us I aurora" (2023), 19 June. Available at: https://aurora-heu.eu/about-us/ (Accessed: February 10, 2025)

and steel mills.[6] It is hoped that data from these efforts will be publicly shared to benefit the entire research and industrial community.

Scope

This study investigates the air quality implications of PCC in heavy industrial processes, focusing on the cement, iron and steel, and refining sectors.

The scope includes establishing baseline emission profiles from existing facilities, with emphasis on before-and-after CCS retrofit data to isolate co-pollutant impacts. Four representative CCS project archetypes were selected to reflect the most viable near- to medium-term deployment pathways:

- Solvent on flue gas (cement) – Brevik CCUS (Norway), Edmonton CCUS (Canada)
- Direct separation reactors (cement) – LEILAC-2 (Germany)
- Solvent on blast furnace gas (iron and steel) – DMX Dunkirk Demonstration (France)
- Solvent on FCC flue gas (refining) – REALISE CCUS (Ireland), AEROSOLVE (Norway)

An extensive literature review was conducted to assess the effect of CCS on non-CO_2 pollutants, with insights drawn primarily from the power sector due to limited industrial data. A gap analysis highlights areas lacking evidence, while potential synergies between CCS and existing air quality control systems are also examined.

Overall, the study provides an indicative assessment of co-benefits and drawbacks for pollutant emissions associated with industrial CCS deployment, supported by archetype case studies, facility data, and literature-based evidence.

Conclusions

A general conclusion is that, at facilities lacking BAT for a given co-pollutant, the installation of an amine-based PCC system is likely to lead to reduced emissions of that pollutant, primarily because of the additional control measures implemented as part of the PCC project. However, in practice, PCC deployment may be more straightforward at facilities that have already adopted BAT, as the incremental capital required for additional co-pollutant controls can be lower and key flue gas conditioning and emissions control infrastructure may already be in place, particularly at newer or recently upgraded sites.

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[6] US DOE (2024) *Multi-Year Program Plan: Point Source Carbon Capture*. US Department of Energy.

Table 1 provides a qualitative assessment of the expected changes in co-pollutant emissions for carbon capture projects deployed beyond BAT. The assessment considers the four project archetypes identified in the study and is based on the reviewed literature and engineering judgment.

	Change in Co-Pollutant Emissions due to Deployment (Confidence)				
Project Archetype	**SO_2**	**NO_X**	**PM**	**NH_3**	**Solvent & Degradation Products**
Solvent on Cement Flue Gas	Decrease **(High)**	Decrease to Increase **(Low)**	Decrease to Increase **(Low)**	Decrease to Increase **(Low)**	Increase **(High)**
Solvent on Blast Furnace Gas	No Impact to Decrease **(Low)**	No Impact to Increase **(Low)**	No Impact to Decrease **(Low)**	No Impact **(Low)**	No Impact **(High)**
Solvent on FCC Flue Gas	Decrease **(High)**	No Impact to Decrease **(Low)**	Decrease **(High)**	Decrease to Increase **(Low)**	Increase **(High)**
Direct Separation Reactors [a]	Decrease to Increase **(Low)**	No Impact **(Low)**	No Impact to Decrease **(Low)**	No Impact **(Low)**	Not Applicable **(High)**

[a] DSR systems in cement plants are expected to be deployed in parallel with amine-solvent based PCC system for the residual CO_2 emissions arising from DSR heating requirements and from the kiln combustion gases. Therefore, all air quality impacts identified for the "solvent on cement flue gas" archetype are likewise applicable to these parallel PCC systems.

Expert Review

Ten expert reviewers from academia and industry provided a broad spectrum of comments. The study was acknowledged as a much-needed and carefully executed survey of industrial sector emissions from CCS, highlighting a major knowledge gap and noting that CCS may be even more relevant for industry than for power generation.

However, reviewers noted that several contextual issues require greater emphasis. Facilities are often assessed in isolation, yet many will operate within industrial clusters where cumulative impacts remain a risk even if individual sites meet regulatory limits. Ammonia slippage was identified as a potential new emission source, and PCC units may reduce exhaust gas temperature and flow, worsening stack dispersion even when absolute emissions decline. Concerns were also raised about overstating the maturity of PCC in industrial applications and emission controls, given limited large-scale deployment, evolving regulatory frameworks, and the lack of monitoring capability for nitrosamines at compliance-relevant concentrations. Finally, while biomass is highlighted as a low-cost mitigation pathway, its role as a source of particulate emissions should not be understated.

Recommendations

- A public health benefits study should be performed using Kuramochi et al.'s (2012) or a similar rigorous methodology to establish the change in co-pollutant emissions. Then, quantification of the benefits can be performed using the methods (the COBRA software tool) outlined in the Great Plains, Clean Air Task Force (CATF), and Frontiers studies. This will strengthen the credibility of public health benefit claims.
- Further research should investigate the composition and potential health impacts of emissions from triethylene glycol (TEG) or mole sieve regeneration vents, which may carry residual amines. This emission point is typically overlooked and may pose localised risks depending on stack design and treatment strategies.
- The impacts on co-pollutant emissions and their interactions with amine-based PCC units during transient events, such as flue gas flow-rate changes and solvent reclaiming, should be investigated to ensure that these effects are not significant enough to warrant additional strategies or controls during such events.
- Regulators are encouraged to proactively predict total NSA and NA concentrations at receptors located near industrial clusters. Such assessments may inform the tightening of allowable limits for permit applicants in order to prevent cumulative impacts that could hinder the deployment of subsequent plants.
- NO_x emission impacts are highly dependent on the heat and power sources selected for amine-based PCC plants. Studies that more precisely quantify these sources would provide significant value in improving the understanding of the true NO_x emission impacts.
- There are conflicting data on NO/NO_2 ratios for NO_x emissions from industrial sources, and uncertainties also remain regarding SO_3 emissions. Taken together, sparse and potentially non-representative NO and NO_2 speciation data and limited SO_3 data reduce confidence in current assessments, supporting the need for targeted multi-plant measurement campaigns and improved monitoring approaches. Targeted studies that quantify these emissions across multiple plants would provide more representative emission rates and improve the reliability of impact assessments.
- It has been hypothesised that ammonium carbonate $(NH_4)_2CO_3$ and ammonium bicarbonate NH_4HCO_3 may form upstream of amine units and contribute to mist-phase emissions. A study in which significant quantities of NH_3 are introduced upstream of an amine unit, followed by analysis of the particulate matter formed, would help determine whether this concern is significant.

IMPERIAL CONSULTANTS

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March 2026

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1 Contents

2 Abbreviations

3D - DMX Dunkirk demonstration

BACT – Best Available Control Technology

BAT - Best Available Techniques

BAT-AEL – Best Available Techniques-Associated Emission Level

BECCS – Biomass Enhanced Carbon Capture and Storage

BF – Blast Furnace

BF-BOF – Blast Furnace-Basic Oxygen Furnace

BFG - Blast Furnace Gas

BOFG - Basic Oxygen Furnace Gas

BREF - Best Available Techniques Reference Document

BSER – Best System of Emission Reduction

CBD – Cement Bypass Duct

CKD – Cement Kiln Dust

CESAR – CO_2 Enhanced Separation and Recovery

CHP - Combined Heat and Power

CO – Carbon Monoxide

CO_2 - Carbon Dioxide

COG – Coke Oven Gas

CPC – Condensation Particle Counters

CPM - Condensable Particulate Matter

COS – Carbonyl Sulfide

CCS – Carbon Capture and Storage

CCUS – Carbon Capture Utilization and Storage

DORA - Dissolved Oxygen Removal Apparatus

DMA – Dimethylamine

DMA – Differential Mobility Analyzers

DRI – Direct Reduced Iron

DSR – Direct Separation Reactors

DRI-EAF – Direct Reduced-Iron Electric Arc Furnace

EOR – Enhanced Oil Recovery

EA – Environmental Agency

EAF – Electric Arc Furnace

EAL – Environmental Assessment Level

EDA – Ethylamine

EEA – European Environment Agency

ELPI – Electric Low Pressure Impactor

EPA – Environmental Protection Agency

EPRI – Electric Power Research Institute

E-PRTR - European Pollutant Release and Transfer Register

ESP – Electrostatic Precipitator

EU – European Union

FCC – Fluidized Catalytic Cracker

FGD – Flue Gas Desulfurization

FG – Flue Gas

FPM – Filterable Particulate Matter

FTIR – Fourier-transform infrared spectroscopy

G1 – Generation 1 Solvent

G2 – Generation 2 Solvent

GC-MS – Gas Chromatography-Mass Spectrometry

GC-TEA – Gas Chromatography – Thermal Energy Analysis

GHG – Green House Gas

H_2 – Hydrogen

H_2S – Hydrogen Sulfide

HAP – Hazardous Air Pollutants

HMeGly – N-(2-hydroxy-1,1-dimethylethyl)-Clycine

HRSG – Heat Recovery Steam Generator

HSS - Heat Stable Salts

IC – Ion Chromatography

IEA - International Energy Agency

IEAGHG – International Energy Agency Greenhouse Gas

IPCC – Intergovernmental Panel on Climate Change

IHCaL - Indirectly Heated Calcium Looping

LC-MS - Liquid Chromatography-Mass Spectrometry

LEILAC - Low Emissions Intensity Lime And Cement

LOD – Limit of Detection

LOQ – Limit of Quantification

MACT – Maximum Available Control Technology

MEA – Monoethanolamine

MHI – Mitsubishi Heavy Industries

MNPZ – Mononitrosopiperazine

NaOH – Sodium Hydroxide

N_2 – Nitrogen

ND – Not Detected

NDEA - N-Nitrosodiethylamine

NDELA - N-Nitrosodiethanolamine

NDMA – N-nitrosodimethylamine

NEI – National Emissions Inventory

NGCC – Natural Gas Combined Cycle

NH_4^+ – Ammonium

Nitroso-HeGly – Nitroso-2-hydroxyethyl-glycine

NMOR – N-nitrosomorpholine

NPL – National Physical Laboratory

NR – Not Reported

NH_3 - Ammonia

NO_X – Nitrogen Oxides

O_3 – Ozone

PC – Portland Cement

PCC – Post Combustion Capture

PEL – Permissible Exposure Limit

PM – Includes both CPM and FPM

PP – Power Plant

PSD – Prevention of Significant Deterioration

SINTEF - Stiftelsen for Industriell og Teknisk Forskning

SCR – Selective Catalytic Reduction

$S_2O_3^{2-}$ – Thiosulfate

SO_2 – Sulfur Dioxides

SO_3 – Sulfur Trioxide

SNCR – Selective Non-Catalytic Reduction

SEWGS - Sorbent Enhanced Water Gas Shift

ROS - Reactive Oxygen Species

TCM - Technology Centre Mongstad

TEG – Triethylene glycol

TGR - Top Gas Recycling

TMOX – 3,4,4-trimethyl-2-oxazolidinone

TNO - Toegepast Natuurwetenschappelijk Onderzoek

TONO - Total Nitrosamines

TRL – Technology Readiness Level

PM – Particulate Matter

$PM_{2.5}$ – Particulate Matter less than or equal to 2.5 µm

PM_{10} – Particulate Matter less than or equal to 10 µm

PTR-ToF-MS – Proton Transfer Reaction – Time-of-Flight – Mass Spectrometer

PZ – Piperazine

PZNO – N-nitrosopiperzine

UK – United Kingdom

US – United States of America

VPSA - Vacuum-Pressure Swing Adsorption

WtE – Waste-to-Energy

3 Executive Summary

This study qualifies and, where possible, quantifies the impact, of carbon capture and storage (CCS) with respect to gaseous pollutant emissions from non-power industrial sources. Particular emphasis is placed on amine-based liquid scrubbing processes, as these represent the most advanced option for near-term commercial deployment. This has been a matter of interest for many years, with potential co-benefits having been suggested in the early 2000s, and more recently concerns about degradation products of amines for post-combustion CO_2 capture being raised. Figure 1 shows the potential effects of a CO_2 capture process on the emissions from a point-source emitter. It is shown that the operation of a CO_2 capture plant[1] could have positive[2] and negative[3] effects on the emissions to atmosphere. This report seeks to investigate the extent to which this occurs.

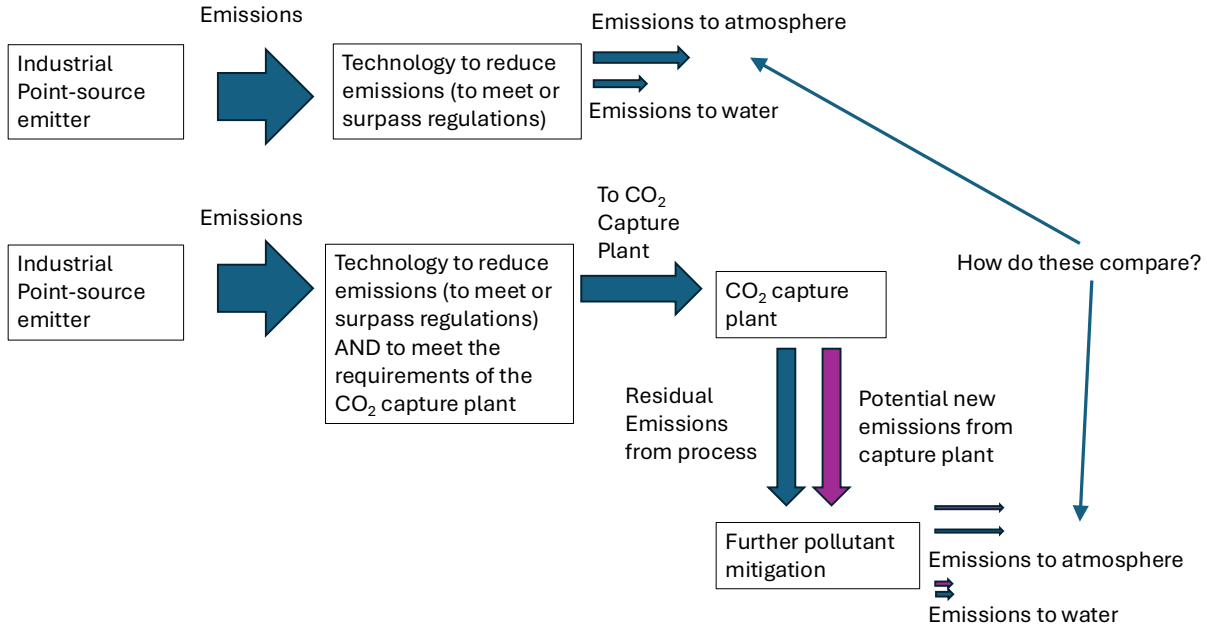

Figure 1. Potential Effects of a CO_2 Capture Process on an Industrial Point Source Emitter.

First, existing emissions of gaseous pollutants such as particulate matter (PM)[4], nitrogen oxides (NO_X), and sulfur dioxide (SO_2) from heavy industry sources equipped

[1] And associated required cleanup prior to the process
[2] Reducing emissions to atmosphere
[3] Introducing new species
[4] Particulate matter (PM) can include both filterable particulate matter (FPM) and condensable particulate matter (CPM). FPM are particles emitted directly as solids or liquids at stack conditions and physically captured on a filter during sampling. CPM are vapours at stack conditions that condense and/or react to form particles when cooled and diluted in the atmosphere. Regulatory monitoring generally focuses on size fractions of PM (e.g. PM_{10}, $PM_{2.5}$). CPM is typically in the fine fraction (≤2.5 µm) and, when included, contributes to PM_{10} totals. Importantly, some regulatory systems (such as U.S. EPA) require reporting of both FPM and CPM ("total PM"), while others (such as the EU) are based on filterable PM only. In this report, when the term PM is used, it should be assumed to be PM_{10} inclusive of both CPM and FPM.

with best available technologies (BAT)[5] for emission control were characterized. The industries selected for this review, cement plants, integrated steel mills, and fluidized catalytic cracking (FCC) units within the oil refining industry, are among those responsible for the highest share of global CO_2 emissions. Best Available Techniques-Associated Emission Levels[6] (BAT-AEL) for these sectors are as low as <10 mg FPM/Nm^3 (except for FCCs), <200 mg NO_X (as NO_2)/Nm^3, and <200 mg SO_2/Nm^3.

Amine-based post-combustion carbon capture (PCC) units are preferably deployed when flue gas pollutant concentrations are already at BAT-AEL. Therefore, if an industrial site lacks BAT controls prior to PCC implementation, the installation of such controls will likely be necessary, resulting in substantial reductions in direct emissions of existing pollutants.

The installation of amine-based PCC units can further influence pollutant emissions, through direct interactions with co-pollutants, the pre-emptive removal of certain species to protect the amine solvent, and fugitive emissions of the capture medium. Within the field of CCS, amine scrubbing is a mature process that has been deployed many times, and the engineering controls associated with preventing emissions are relatively well understood, though each novel combination of process and capture system needs to be validated.

It has been theorized that the overall impact of these influences will result in a decrease in health impacts associated with existing co-pollutant emissions. However, health impact studies use gravimetric PM measurements as one of the inputs to their analysis. Owing to the type of experimental methods used at pilot plants, gravimetric data on emissions are scarcely available.

The available evidence does suggest that if upstream controls, such as baghouse filters or Brownian diffusion units (BDU), are not installed upstream of an amine unit, the amine unit itself may act as a PM reduction device. Since baghouse filters are already commonly used in industries, such as cement, it remains unclear whether an amine unit continues to provide additional PM removal when such filters are in place. In cases where PM is significantly reduced before entering the amine unit, condensable PM (CPM) may increase from the lowered baseline due to the nucleation of aerosols within the PCC unit.[7]

In the specific case of FCCs, there is a greater likelihood that additional PM reductions will be observed when amine-based PCC is deployed. This is because BDUs or other upstream PM control devices are expected to be installed. These are required for the following three key factors:

[5] BAT and BAT-AEL are defined in Section 5.1.

[6] As stated in the European Union BAT refences documents.

[7] Control measures for these emissions are discussed in Section 6.5.3, 6.5.4, and 6.5.5.

- In some regions, the allowable emission limits for FPM at FCCs are disproportionally higher than other industries.[8] .
- FCC PM includes catalyst dust, which can be particularly harmful to amine solvents.
- The only amine-based PCC pilot plant to test FCC-derived flue gas was unable to operate without a BDU upstream of the plant due to mist-phase emissions.

Amine solvent-based PCC units can operate effectively with NO_X concentrations at BAT-AEL. Minor reductions beyond BAT-AEL may be observed, driven by the desire to prevent amine degradation caused by NO_2. Thiosulfate scrubbing can remove NO_2, but since NO_2 typically accounts for less than 5% of total NO_X, overall NO_X reductions are limited to <5%.

SCR systems can also be installed upstream of amine-based PCC plants to reduce total NO_X entering the plant. However, SCRs may not be necessary to avoid solvent degradation and, therefore, their use should be balanced against their significant capital expenditures.

At cement plants, deployment of amine PCC may lead to an increase in NO_X emissions depending on the source of heat and power used for the PCC plant. This is because such plants typically lack dedicated heat and power generation facilities. As a result, the installation of facilities for the combustion of natural gas or other fuel to meet the heat and power demands of the PCC unit can generate additional NO_X. These additional emissions can be reduced below the level of NO_2 removed by thiosulfate or SCRs by using natural gas combined heat and power plants with SCRs, heat pumps, or electric steam generators instead of gas fired boilers.

SO_2 emissions are expected to decrease following amine PCC installation. This is due to the requirement for SO_2 scrubbing from the inlet gas to prevent amine solvent neutralizing. Exit concentrations from the PCC unit are typically significantly below 1 ppmv well below BAT-AEL. The predicted reduction in SO_2 emissions at cement plants and FCC units is estimated to range from 98.4% to 99.9%.[9]

[8] In, the European Union BAT-AELs for FCCs allow FPM emissions up to 50 mg/Nm^3. However, in the US, the NSPS for FPM emissions at FCCs are approximately 17 mg/Nm^3.
[9] See Section 9.1.6 for calculation assumptions.

Amine-based PCC units also potentially introduce new pollutant emissions, including:

- Amines[10, 11]
- Carbonyl species[12]
- Ammonia[13]
- Nitrosamines and nitramines[14]

Modelling studies of proposed amine-based carbon capture projects indicate that ground-level concentrations of direct and indirect nitrosamines (NSAs) and nitramines (NAs) are expected to remain below regulatory limits. However, maintaining these low concentrations may become increasingly challenging as additional carbon capture units are deployed within industrial clusters. Further research is needed to assess the environmental persistence of NSAs and NAs.

This report generally relied on academic and open-source literature to make conclusions and recommendations rather than a focused review of air emissions or water discharge permit applications. Therefore, this review identified a general lack of publicly available emissions data from amine-based PCC plants operating in the cement and iron and steel industries. This is largely attributable to the fact that publicly funded pilot projects in these sectors have only recently been initiated. Non-redacted permit applications often contain dispersion studies and specific values for the emission of pollutants. A future study focusing on permit applications for large-scale amine-based PCC projects would provide a valuable complement to the present work.

This report also noted a lack of analysis regarding the impacts of non-amine-based CCS approaches on gaseous emissions. Projects involving pre-combustion capture[15] on steel mill blast furnace gas or emerging technologies such as direct separation reactors have not been studied in this context. This suggests a significant opportunity for researchers, technology providers, and industry stakeholders to better understand potential emission impacts.

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[10] Second generation solvents can be controlled to <1 ppmv with emission control devices such as water washes, upstream filters, and dry beds.

[11] Ammonia may already be an emission at locations utilizing SCR or NSCR systems. The reason for this is discussed in Section 6.5.7.

[12] Emission control devices have proven ineffective at controlling aldehydes. Emissions of individual species are typically <100 ppb. Ground level emission can be controlled with stack heigh and atmospheric dispersion.

[13]Amine emissions from first and second-generation solvents can be controlled to <5 ppmv with acid washes.

[14] Their formation is highly dependent on solvent selection. Their impacts mitigated through solvent choice and management via stack height and atmospheric dispersion.

[15] Although pre-combustion capture technologies exhaust flue gas stream rather than emissions to atmosphere. These technologies can have an impact on co-pollutant emissions as discussed in Section 9.1.

Existing studies which attempt to quantify the public health benefits of CCS deployments suffer from questionable assumptions, insufficient data on PM reductions, and an exclusive focus on amine-based solvent PCC technologies. The most tenuous assumption in these studies is the expectation that equipment exceeding BAT standards will be installed. This is an outcome that is highly unlikely except in the case of pre-scrubbers for SO_X reduction and, perhaps, filters for PM at amine-plants deployed for fluid catalytic cracking (FCC) units. There may be scenarios where specific amines require flue gas specifications exceeding BAT-AELs. However, this does not appear to be the case for the open-source solvents considered in this report. In summary, the qualitative conclusions of these public health studies suggest significant public health benefits, the lack of comprehensive data and methodological rigor weakens their credibility.

This review also briefly addressed liquid and solid waste streams. It was determined that the characterization and management of liquid waste streams, particularly acid wash residues, remain poorly addressed in the literature.

Finally, two notable synergies were identified:

1. Ammonia, commonly used as a reductant in selective and non-selective catalytic reduction (SCR/SNCR) for NO_X control, may exhibit reduced atmospheric slip when acid washes are implemented at amine-based PCC plants.
2. Liquid and solid waste streams generated from PCC processes may be incinerated in cement kilns, offering a viable disposal method if undesirable compounds are found after waste characterization.

4 Introduction

4.1 Context

Carbon capture and storage (CCS) is a critical element in achieving net-zero greenhouse gas emissions, and is particularly important at high penetration rates of renewables (van Vuuren *et al.*, 2015). The Intergovernmental Panel on Climate Change (IPCC) utilizes CCS in many of the scenarios that lead to lower than two degrees Celsius of warming, and failure to use it leads to significant extra costs to decarbonize (van Vuuren *et al.*, 2015). Carbon capture technologies are well established in the decarbonization of power generation and hydrogen production. CCS plays a vital role in energy systems transitioning to low-carbon operations while still allowing some use of fossil fuels. Increasingly, full-scale and pilot-scale deployments are being initiated in hard-to-abate industrial sectors, including cement and iron and steel production. In particular, CCS is indispensable for decarbonizing process emissions in the cement, lime, and refining industries[16], emissions that cannot be eliminated through fuel switching alone.

Although global CCS deployment is experiencing rapid growth, it has yet to achieve the scale required to address the climate crisis, which is to prevent the emission of billions of tonnes of CO_2 annually. Additionally, when combined with the use of biomass, the technology allows relatively[17] inexpensive net CO_2 removal from the atmosphere.[18]

The impact of carbon capture on air quality is an important consideration that has not always been fully explored, with most studies in the general field of CCS investigating features such as reaction kinetics, reboiler duties, heats of reaction, or economics. The magnitude of human health impacts from air quality changes can be comparable to their carbon reduction benefits depending upon the value of a statistical life or social cost of carbon assumed.

Factors such as ambient concentrations of byproduct pollutants and their environmental persistence need to be taken into account when assessing the environmental implications of deploying CCS. Furthermore, retrofitting existing emission sources with carbon capture systems can change the emission profile of pollutants. Emissions of some existing species' pollutants[19] may decrease, others may increase, and new substances could be introduced into the environment.[20]

[16] Fluidized catalytic cracker coke burn-off

[17] Compared to direct air capture.

[18] Biomass combustion plants are a significant source of PM, which presents technical challenges for the implementation of amine-based PCC systems. Elevated particulate loadings can contribute to increased solvent degradation, operational fouling, and higher maintenance requirements, thereby complicating long-term system reliability. Moreover, the additional burden of particulate and secondary emissions on local air quality must be carefully assessed.

[19] Such as sulphur dioxide, nitrous oxides, and particulate matter.

[20] Pollutants other than CO_2 are referred to as "co-pollutants".

In regard to new substances, it is also important to emphasize that the emission of amines and other volatile organic compounds relevant to this study is not unique to carbon capture applications, but rather occurs across a wide range of industrial processes and sectors. In fact, this issue has been recognized for decades, and in some countries, such as Germany, clear regulatory frameworks already exist. For example, the TA Luft (Technical Instructions on Air Quality Control) provides emission standards for diverse facilities, including metal annealing ovens, foundries, and rock wool production plants, as well as for agricultural sources such as pig farms, which release alcohols, aldehydes, amines, ammonia, and other organic compounds.[21]

A wide range of factors influence how CCS affects air quality. These include the characteristics of the underlying industrial process, particularly the age of the facility and whether it has been upgraded since its construction, as well as the presence and effectiveness of existing emission mitigation measures, which are often determined by the best available technology (BAT)[22] standards in place at the time of installation.

Additional mitigation systems, such as filters, scrubbers, solvents or sorbents, may be added ahead of CCS implementation to protect the capture system itself. The type of CCS technology used can further influence emissions, especially in solvent-based systems, where the choice of solvent and any downstream controls like water washes[23] or stack configurations play an important role. Additionally, local environmental conditions affect how pollutants disperse or deposit onto land or into water, shaping the overall impact on air quality.

Local regulations[24] concerning emissions limits of different types of pollutants will have a significant impact on both the decision to deploy CCS and the emission profile resulting from the deployment of CCS. Technology providers and operators will need to design and install CCS systems which meet these regulations. The application of CCS has the potential to improve local air quality of some co-pollutants if its deployment triggers upgrading existing updated pollution control technologies to BAT standards. However, the requirements of such regulations could present economic challenges that may hinder CCS deployment.

Furthermore, as with the development of any new process, there are gaps in understanding during the advancement of the process from the laboratory through pilot testing and on to full-scale deployment. As more experience is developed with a process, the gaps change from those in fundamental understanding, to improvements of engineering design. Within the field of CCS, amine scrubbing is a mature process that has been deployed many times, and the engineering controls associated with

[21] The same is true for other regulatory frameworks.
[22] Defined in Section 5.1
[23] Defined in Section 6.3.3
[24] Including historical regulations and any grandfathering rights.

preventing emissions are relatively well understood, though each novel combination of process and capture system needs to be validated.

Previous comprehensive literature reviews on the impact of CCS deployment on air quality have primarily focused on the coal and natural gas power industries or have not addressed the impacts on co-pollutants (SEPA, 2015; Buvik *et al.*, 2021; Gibbins, Lucquiaud and Samson, 2024; Rochelle, 2024)[25]. However, the industrial sector is a significant contributor to global greenhouse gas emissions, contributing around 25 % (GCCSI, 2016), with key industries such as cement, iron and steel, and refining being responsible for a broad spectrum of pollutants beyond carbon dioxide (CO_2). Therefore, there is a clear need for a comprehensive study such as this one, that specifically examines the impact of CCS deployment in these industries, with particular attention to its effects on air pollutants currently emitted by the industries.

4.2 Project Objectives and Scope

This report, prepared by researchers from Imperial College London for the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG), aims to address the knowledge gaps identified in section 4.1. The study focuses on the air quality implications of post-combustion CO_2 capture across various industrial sectors. It evaluates how these technologies influence the emission profiles of pollutants other than CO_2 and explores the potential co-benefits and drawbacks associated with their deployment.

The study examines the largest CO_2-emitting sectors of heavy industry; cement[26], iron and steel[27], and refining[28]. The geographic scope is limited to North America and Europe as these regions represent some of the major sources of industrial emissions where CCS deployment is expected to play a significant role within the coming decades. A gap analysis was conducted to identify research areas that are currently underexplored. In addition, the study investigates potential synergies between existing air quality control technologies and CCS systems.

4.3 Structure

To assess the potential air quality impacts of CCS deployment in heavy industry, it was first necessary to establish the baseline emission profiles[29] of key industrial sectors. This characterization effort, detailed in Section 5, focused on the existing emissions

[25] The authors are unaware of existing literature reviews examining the impact of CCS deployment in industries and projects that combust biomass or materials with high biogenic content, such as waste-to-energy (WtE) and bioenergy with carbon capture and storage (BECCS). This report does not specifically address biomass combustion. However, studies in this field were included when relevant for context.
[26] 6.5-7 % of global emissions (Czigler *et al.*, 2020; Fennell, Driver, *et al.*, 2022)
[27] 7-8 % of global emissions (Czigler *et al.*, 2020; Fennell, Driver, *et al.*, 2022)
[28] 4% of global emissions (Ma *et al.*, 2023)
[29] Prior to CCS deployment.

from cement, iron and steel, and refining industries both in general terms and at specific facilities where CCS technologies have been or are being deployed.

Existing facilities were established as the baseline for this study because they establish a meaningful counterfactual when assessing the co-pollutant implications of CCS deployment. For retrofits in particular, a comparison of emissions from the same facility before and after CCS installation generally provides a more robust reference point than comparisons between different facilities, one with CCS and one without. The latter approach can introduce confounding factors related to plant age, feedstock composition, technology configuration, and operational practices, all of which vary significantly across industrial sites.

By contrast, before-and-after data at a single facility directly isolates the effect of CCS while holding constant many of these other variables. This makes the emission reductions (or increases) attributable to CCS both more transparent and more defensible for policy and planning purposes. Where such data exist, they allow for a clearer understanding of the marginal impact of CCS deployment on co-pollutant emissions, thereby improving the accuracy of projections.

While a wide range of CCS technologies exist at varying technology readiness levels (TRLs), only a subset is likely to be deployed at scale in the near to medium term, based on technological maturity and economic feasibility. To ensure the analysis remained grounded in realistic deployment scenarios, four representative CCS project archetypes were selected. These archetypes reflect technologies considered most viable for large-scale adoption across the cement, iron and steel, and refining sectors. Certain technologies that may be more favorable in the long term were intentionally excluded from this analysis[30].

By establishing these archetypes and collecting corresponding emissions data from the facilities employing these archetypes at the outset, the report was able to use them as informal case studies throughout. Insights from the literature were applied to each archetype, and the report's conclusions draw upon these examples to provide an indicative assessment of the likely air quality impacts associated with industrial CCS deployment.

Following the characterization of existing emissions and the establishment of CCS project archetypes, an extensive literature review was conducted to assess the impact of CCS deployment on air quality. The insights and findings from this review are presented in Section 6. Due to the relative infancy of CCS deployment in the cement,

[30] For example, direct reduced iron (DRI) using green or blue hydrogen in the iron and steel sector, which may be more suitable for long-term decarbonization but is not yet widely deployable. And, to the author's knowledge, no DRI pilot-projects exist within the established geographical area of interest.

iron and steel, and refining industries, many of the findings are drawn from studies conducted in the context of power generation.

Information that would have been valuable for this review but was not identified in the existing literature is highlighted as knowledge gaps in Section 7. Potential synergies between existing heavy industry processes and CCS deployment are explored in Section 8.

Finally, Section 9 presents the conclusions and recommendations. As discussed, insights from the literature review (Section 6) were applied to assess the likely changes in co-pollutant emissions for the four archetypes established in Section 5. Confidence levels for these projected changes were also provided, based on the gap analysis conducted in Section 7.

5 Characterization of Existing Air Emissions

5.1 Archetype Selection

To identify the four archetypes most relevant to this study, a review of applicable CCS projects was conducted. Ideally, selected projects would involve large-scale[31] industrial CCS deployments, as these provide strong evidence of industry adoption and potential for widespread implementation. However, in sectors such as refining, the deployment of large-scale CCS systems remains limited. Therefore, pilot-scale projects were also considered to ensure that these sectors were not excluded from the analysis.

To capture both pilot-scale and full-scale projects, two separate project lists were compiled. The first comprised recent pilot-scale research initiatives led by the Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek (TNO) or Netherlands Organisation for Applied Scientific Research and Stiftelsen for Industriell og TEknisk Forskning (SINTEF) or the Foundation for Industrial and Technical Research was developed. This list was assembled by reviewing project information published on the respective organizations' websites and supplemented by the authors' familiarity with these initiatives.

The second list was developed using the International Energy Agency (IEA) CCS Project Database, which includes only those projects with a capture capacity exceeding 100 $ktCO_2$/year. The following filtering criteria were applied:

- **Industry**: Cement, Iron and Steel, Chemicals, Hydrogen or Ammonia, and Other Fuel Transformation.[32]
- **Region**: North America, Europe, Other Asia Pacific, and Australia and New Zealand.
- **Status**: Operational, under construction, or planned to be operational by 2027.[33]

A targeted review of grey literature[34] associated with the identified projects was undertaken to determine the CCS technology archetype used and the corresponding TRL level achieved or anticipated[35]. All projects were then categorized within a comprehensive technology archetype framework, summarized in Table 2.

[31] >100,000 tCO_2/year Captured

[32] Refining projects are included in the "Other Fuel Transformation" category of the IEA database, hence their inclusion.

[33] Only operational or under-construction projects were considered for hydrogen, ammonia, and other fuel transformation projects. This limitation was applied because the very large number of announced but not under construction, or in operation, blue hydrogen projects in these sectors made a thorough review unfeasible.

[34] Grey literature is literature that has not gone through a formal academic review process.

[35] The authors made their best effort to assign TRLs based on the available grey literature. However, TRL definitions can vary between organizations and may be somewhat subjective. The specific definitions used for TRLs in this report are provided in Appendix 1.

Table 1 – Joint R&D projects Coordinated by TNO and SINTEF on Pilot Scale CCS Research Projects and the TRL Achieved for the Associated Technology Archetype

Project Name	Dates	Technology Archetype	Leading Organization	TRL Achieved / Expected	Sources
CEMCAP	2015-2018	Cement Oxyfuel Kiln, Calcium Looping, Membranes, and Chilled Ammonia	SINTEF	Cement Oxyfuel Kiln – TRL 6 Calcium Looping – TRL 4	(Carrasco *et al.*, 2018; Lino *et al.*, 2018; Paneru *et al.*, 2018; Jordal *et al.*, 2019; *Partners*, 2025)
CLEANKER	2017-2023	Calcium Looping	LEAP [a]	TRL 7	(Jordal *et al.*, 2019; S.r.l, 2025)
ANICA	2019-2022	IHCaL	TUD [a]	TRL 6	(Greco-Coppi, Hofmann and Ströhle, 2024; *Advanced Indirectly Heated Carbonate Looping Process — ERA-LEARN*, 2025)
STEPWISE	2016-2021	SEWGS	TNO	BFG – TRL 6	(Van Dijk *et al.*, 2019; *CCU Projects Database*, 2025; *Enabling carbon capture and storage with Sorption Enhanced Water Gas Shift (SEWGS) technology*, 2025; *SEWGS: technology for CO2 reduction | TNO*, 2025)
INITIATE	2020-2025	SEWGS	TNO	BOFG – TRL 7 (expected)	("About the project | INITIATE Project," 2025; "CONSTRUCTION UPDATE TIME: The Progress of the INITIATE Pilot Plant | INITIATE Project," 2025; "TNO | INITIATE Project," 2025)
AEROSOLVE & MEA-4	2016-2018	Amine on FCC FG (MEA [b])	SINTEF	FCC Flue Gas = TRL 7	(Shah *et al.*, 2019)
ALIGN-CCUS	2017-2021	Amine on NGCC FG Amine on Coal PP FG (MEA and CESAR1 [b])	TNO	NGCC Flue Gas = TRL 7 Coal PP Flue Gas = TRL 7	(Shah *et al.*, 2019; Moser *et al.*, 2020; Benquet *et al.*, 2021; Van Os *et al.*, 2021)
LAUNCH	2019-2022	Amine on Coal PP FG (CESAR 1 [b])	TNO	Studying Amine Degradation	(Moser, Wiechers, Schmidt, Veronezi Figueiredo, *et al.*, 2023; RWE, 2025; *LAUNCH - Lowering absorption uncertainty and costs by predicting and controlling amine degradation — ERA-LEARN*, 2025)
REALISE	2020-2023	Amine on Refining FG (HS-3 [b])	SINTEF	TRL 6	(Mejdell *et al.*, 2022; Michalski *et al.*, 2022; Skylogianni, Grimstvedt, *et al.*, 2022; SINTEF, 2025)
SCOPE	2022-2024	Amine on Coal PP FG (CESAR 1 [b])	SINTEF	Developing Emission Control Guidelines	(Kvamsdal *et al.*, 2022; *SCOPE*, 2025)
ACCESS	2021-2025	Enzyme on Pulp Mill FG Enzyme on Cement FG	SINTEF	TRL 7 (expected)	(*Activites – Accsess*, 2025; *ACCSESS Innovation Project | Saipem*, 2025; "Organisation – Accsess," 2025)
AURORA	2023-2026	Amine on Refining FG Amine on Cement FG (CESAR1 [b])	SINTEF	TRL 7/8 (expected)	("About us | aurora," 2023; Fovelle, 2024, 2024)

[a] These projects were not led by TNO or SINTEF. However, they are included because they are key follow-on efforts after CEMCAP. [b] Descriptions of these amine solvents are described in Section 6.1.2.

Table 2 – Summary Table of CCS Technology Archetype and Associated Projects in the Cement, Iron & Steel, and Other Industries

Industry	ID	Archetype	Current TRL	Post CC?	Key Projects	Year Operational	Capacity (MtCo2/year)	Source
Cement	1	**Solvent on Flue Gas**	7	Yes	**Heidelberg Materials Brevik Cement**	2025	0.4	1, 2, 4
					Carbon Clean CEMEX Rudersdorf Plant Phase 1	2026	0.11	1, 16
					HeidelbergMaterials Edmonton Cement (ALB)	2027	1	1, 33
					ACCESS	2025	Pilot Scale	See Table 1
					AURORA	2026	Pilot Scale	See Table 1
	2	Sorbent on Flue Gas	7	Yes	CO2MENT LafargeHolcim Florence (CO)	2025	1.5	1, 17, 18
	3	Partial Oxy-Combustion and Cryo Distillation on Flue Gas	6	Yes	Go4ECOPlant Lafarge Polska Kujawy plant	2027	1.02	1, 32, 50
	4	Oxy-Combustion	6	Oxy-Comb	Carbon2Business LafargeHolcim Laegerdorf	2027	1	1, 30, 31
	5	**Direct Separation Reactor**	7	No	**Heidelberg Materials LEILAC 2**	2025	0.1	1, 3
	6	Calcium Looping	6-7	Yes	CEMCAP	2018	Pilot Scale	See Table 1
					CLEANKER	2023	Pilot Scale	See Table 1
					ANICA	2023	Pilot Scale	See Table 1
Iron & Steel	7	**Solvent on Blast Furnace Gas**	7	Pre-Comb	**3D DMX ArcelorMittal and IFPEN Dunkirk (full-scale)**	2025	0.7	1, 21, 22
	8	SEWGS on BFG and BOFG	6	Pre-Comb	STEPWISE	2018	Pilot Scale	See Table 1
					INITIATE	2024	Pilot Scale	See Table 1
Other Industries (**Chemical**, **Fertilizer**, and **Refining**)	9	**Solvent on Flue Gas**	6-7	Yes	**AEROSOLVE** (Refining)	2018	Pilot Scale	See Table 1
					REALIZE (Refining)	~2023	Pilot Scale	See Table 1
					AURORA	2026	Pilot Scale	See Table 1
	10	Coal, Petcoke, or Refining Residue Gasification	9	Pre-Comb / **Blue H2**	8 Chinese Projects (Coal-to-Liquids Plants / CO2 Destined for EOR)	2015-2024		1, 2, 6, 25, 10, 44, 48
					Great Plains Synfuel Plant (ND) Weyburn-Midale (SK)	2000	3	1, 42
					Coffeyville Fertiliser Plant (KS)	2013	0.9	1, 7
					NWR Sturgeon Refinery (ALB)	2020	1.3	1, 45
					Shell Netherlands Refineries Heavy Residue Gasification **CCS**	2026	0.75	1, 46
	11	Steam Methane Reforming	9	**Blue H2**	Enid Fertiliser (OK)	1982	0.68	1, 9
					Valero Port Arthur Refinery (TX)	2013	0.9	1, 36
					PCS Nitrogen-Geismar plant (LA)	2013	0.3	1
					Quest (ALB)	2015	1.1	1, 37
					Nutrien Redwater Fertilizer (ALB) phase 1	2020	0.3	1
					Linde Clear Lake HyCO Plant (TX)	2023	0.18	1, 49
					7 North American and European Projects Under Construction	2025-2026		1, 13, 38, 34, 35, 40, 41
	12	Autothermal Reforming	9	**Blue H2**	Net-Zero Hydrogen Energy Complex (ALB)	2024	Not Reported	1, 15
					Linde Hydrogen Plant for OCI Fertilizer Blue Ammonia Beaumont (TX)	2025	1.7	1, 14
					KeyState Natural Gas Synthesis (ARCH2) (PA)	2026	0.5	1, 27
					Dow Fort Saskatchewan Path2Zero (ALB)	2029	Not Reported	1, 8

A key connecting the sources in this table to the bibliography is provided in Appendix 2. Projects selected for characterization are in **bold purple**

As shown in Table 1 , which summarizes research projects led by SINTEF and TNO, pilot-scale studies on cement plant applications have historically focused on oxyfuel kilns and calcium looping. These technologies were prioritized due to their potential for high overall efficiency and a high carbon capture rate. However, recent research efforts have shifted toward solvent-based post-combustion capture. Notably, the AURORA and ACCSESS projects are applying amine- and enzyme-based capture technologies to cement flue gas streams.

In the iron and steel sector, the reviewed research projects from these institutions have exclusively focused on sorbent-enhanced water-gas shift (SEWGS) technology. For the refining industry, completed and ongoing projects have concentrated on various post-combustion solvent-based capture approaches.

Table 2 summarizes all projects identified through the two compiled lists. Within the cement industry, multiple CCS technology archetypes are being explored by both industrial and research stakeholders. However, among these, solvent-based post-combustion capture applied to cement flue gas has emerged as a prominent approach,

supported by three large industrial projects currently in progress. Accordingly, this pathway was chosen as the first CCS technology archetype for detailed analysis.

Direct separation reactors (DSRs) have also gained attention as a promising technology, primarily due to their relatively low CO_2 capture costs (even in unoptimized configurations) estimated at £39–53 per tonne of CO_2 captured (Driver et al., 2022). Furthermore, modern cement plants are typically highly heat-integrated and often located in remote areas, which limits the availability of surplus heat or opportunities for cross-industry heat integration to support solvent regeneration in an amine-based system (Gibbins, Lucquiaud and Samson, 2024).

DSR technology offers a significant advantage by abating approximately 60–65% of carbon emissions, thereby substantially reducing the energy required for a Post Combustion Capture (PCC) unit to capture the remaining emissions when the kiln and direct separation reactor are fired with fossil fuels. Given these advantages and its growing relevance, the Low Emissions Intensity Lime and Cement (LEILAC) was selected as the second archetype for further analysis.

Only two CCS technology archetypes were identified for the iron and steel industry: solvent-based pre-combustion capture applied to blast furnace gas (BFG) and SEWGS. [36, 37, 38] Among these, the DMX Dunkirk Demonstration (3D) project by ArcelorMittal, which involves pre-combustion capture of BFG, was selected as the third archetype for this study, as it is the only large-scale CCS initiative currently identified in the sector.

The CCS projects identified in the refining industry fall into two primary categories: (1) blue hydrogen projects and (2) solvent-based capture from refinery flue gas. In a typical U.S. refinery, hydrogen production accounts for only 5.8% of total CO_2 emissions (Bains, Psarras and Wilcox, 2017). While blue hydrogen projects such as Port Arthur

[36] An iron and steel project of note that was excluded due to geographical filtering of the second list was the Al Reyadah Carbon Capture, Utilization, and Storage project in the United Arab Emirates. This plant uses a reduces raw iron with a natural gas fed DRI process, and the CO2 generated during iron reduction is captured with a monoethanolamine (MEA) solvent and used for Enhanced Oil Recovery (EOR) (Zahra, 2025; *Al Reyadah Details*, 2025). The IEA expects green and blue hydrogen-fed DRI processes to play a key role in the decarbonization of the iron and steel industry (*Iron and Steel Technology Roadmap – Analysis*, 2020). However, DRI-based CCS projects were excluded from this review due to their longer-term deployment horizon.

[37] There are three major steel mill configurations: the Blast Furnace-Basic Oxygen Furnace (BF-BOF) pathway, the Scrap-Electric Arc Furnace (Scrap-EAF) pathway, and the natural gas-fed Direct Reduced Iron-Electric Arc Furnace (DRI-EAF) pathway. Approximately 73% of the world's steel is produced through the BF-BOF pathway, while 5% is produced via the DRI-EAF pathway (Steel Sector Overview | CBS Insights, 2023). Switching from the BF-BOF pathway to the DRI-EAF pathway results in a reduction of carbon emissions, even if carbon is not captured from the DRI process. However, the impact of transitioning from one method of production to another was not explored in this report.

[38] Another project of note not identified was the ULCOS Top Gas Recycle Blast Furnace pilot plant in Luleå, Sweden. The pilot plant demonstrated a reduction in CO_2 emissions by using pure oxygen instead of air, capturing CO_2 from the blast furnace gas, and recycling the majority of the blast furnace gas. This pilot campaign achieved a CO_2 reduction of up to 76% and an estimated net reduction of around 65% for the steel hot-rolled coil production (Danloy *et al.*, 2009).

and Quest are important for decarbonizing existing hydrogen production[39], they do not address the primary emission sources in refineries, which stem from fuel combustion (63%) and coke burn-off in fluidized catalytic crackers (FCCs) (24%) (Bains, Psarras and Wilcox, 2017).

For this reason, small-scale research projects such as AEROSOLVE, REALISE, and AURORA, though not large in scale, were identified as important demonstrations of CCS in the refining sector. However, AURORA was excluded from selection due to its ongoing status and lack of available performance results at the time of this review.

Among all refinery flue gas streams, the FCC catalyst regenerator flue gas is of particular interest. It cannot be decarbonized through hydrogen substitution, as its CO_2 emissions originate from the combustion of coke accumulated on the catalyst surface. This stream also carries the highest co-pollutant burden within the refinery, containing significant levels of particulates, sulfur, and nitrogen compounds. For these reasons, solvent-based CO_2 capture from FCC flue gas was selected as the fourth technology archetype in this study.

Table 3 – Summary of Archetypes and Projects Selected for Analysis

Archetype	Industry	Project Name	Location
Solvent on Flue Gas	Cement	Brevik CCUS	Norway
		Edmonton CCUS	Canada
Direct Separation Reactors		LEILAC-2	Germany
Solvent on Blast Furnace Gas	Iron and Steel	DMX Dunkirk Demonstration	France
Solvent on FCC Flue Gas	Refining	REALIZE [a]	Ireland
		AEROSOLVE	Norway

[a] As discussed in Section 5.4.3, multiple stacks were tested during the REALIZE project at the Whitegate refinery. The stacks were not labeled in the work packages. Therefore, it is not clear if an FCC stack was tested.

Table 3 summarizes the projects selected for analysis in this report. These projects span a broad range of CCS technology types, including post-combustion capture, pre-combustion capture, and direct separation reactors.

The three sections (5.2, 5.3, and 5.4) that follow begin with descriptions of the CO_2 emission source and characterize typical emissions from the sources represented by the projects in Table 3. These descriptions encompass emissions both pre- and post-the application of BAT. Then, brief descriptions of each selected project are provided, and an effort is made to characterize the site-specific emission profiles prior to CCS deployment.

Given that many of the key industry projects are located within the European Union (EU), the EU Best Available Techniques Reference Documents (BREFs) serve as a logical and authoritative source for establishing emission profiles under BAT conditions. These

[39] Blue hydrogen projects which generate hydrogen for use in boilers rather than hydrogenation processes (e.g. hydrocracking) could ultimately have a significant impact on decarbonizing the refining industry.

documents provide detailed information on flue gas characteristics, emission limits, and recommended control technologies for the relevant industries. The emission limits, referred to as Best Available Techniques-Associated Emission Levels (BAT-AELs), are derived from survey data reflecting the performance of leading technologies under economically and technically feasible conditions. In addition to regulatory benchmarks, the BREFs include aggregated emissions data for sites not operating under BAT, offering valuable context for understanding typical performance across industrial sites.

The closest U.S. analogues to the BAT-AELs used in the European Union and the United Kingdom are the New Source Performance Standards (NSPS) and Maximum Available Control Technology (MACT) emission limits, as both establish enforceable numerical thresholds for specific source categories. NSPS applies to criteria pollutants (e.g., SO_2, NO_x, PM, CO), whereas MACT regulates hazardous air pollutants (HAPs) (e.g., formaldehyde, benzene, certain amines). In the U.S., the underlying control basis for NSPS is the Best System of Emission Reduction (BSER), which is conceptually equivalent to BAT as defined in the EU BREFs. Furthermore, at the US state level, under the Prevention of Significant Deterioration (PSD) program, case-by-case determinations of Best Available Control Technology (BACT) are required, which also serve a role similar to BAT. In this report, specific BAT-AEL values provided are from EU legislation. However, when a specific value is not provided, the term BAT-AELs is used generically to represent regulated emission limits across jurisdictions, and BAT is used to denote best-practice emission control technologies, irrespective of regional terminology. Although limits and regulatory frameworks differ, the underlying technologies remain largely consistent; therefore, using BAT-AEL for limits and BAT for technologies does not compromise the intent of this report.[40]

5.2 Cement Plants

5.2.1 Process Description

The production rate of cement has increased faster than gross domestic product (GDP) throughout approximately the last century. Around 3.5 billion tonnes of cement are produced each year, with ~63% being manufactured in China (2.2 billion tonnes) and ~9% in India (*China: leading cement producers by clinker capacity 2018*, 2025). Emissions of CO_2 from cement production are significant, comprising approximately 6.5-7% of global anthropogenic direct emissions. These emissions derive from two main sources during production, with the majority[41] from calcination of the main feedstock, and the remainder[42] from fuels used to provide heating for the process

[40] In the author's opinion, the EU system framework is significantly less complex than the US framework. This is another justification for the use of EU terms in this context.
[41] Approximately 60%
[42] Approximately 40%

(Davis *et al.*, 2018). Equation 1 illustrates how CO_2 is liberated from limestone ($CaCO_3$) during the calcination process.

Equation 1: $$CaCO_3 \rightarrow CaO + O_2$$

The vast majority of the cement produced is Portland cement (PC), which has undergone considerable development to greatly improve many of its qualities as a binder (e.g., setting time, workability, strength) since it was first patented in 1824. A brief summary of cement production is discussed below, accompanied by a diagram highlighting the main stages in Figure 2. The overriding majority of cement production is now done in a dry process rotary kiln.

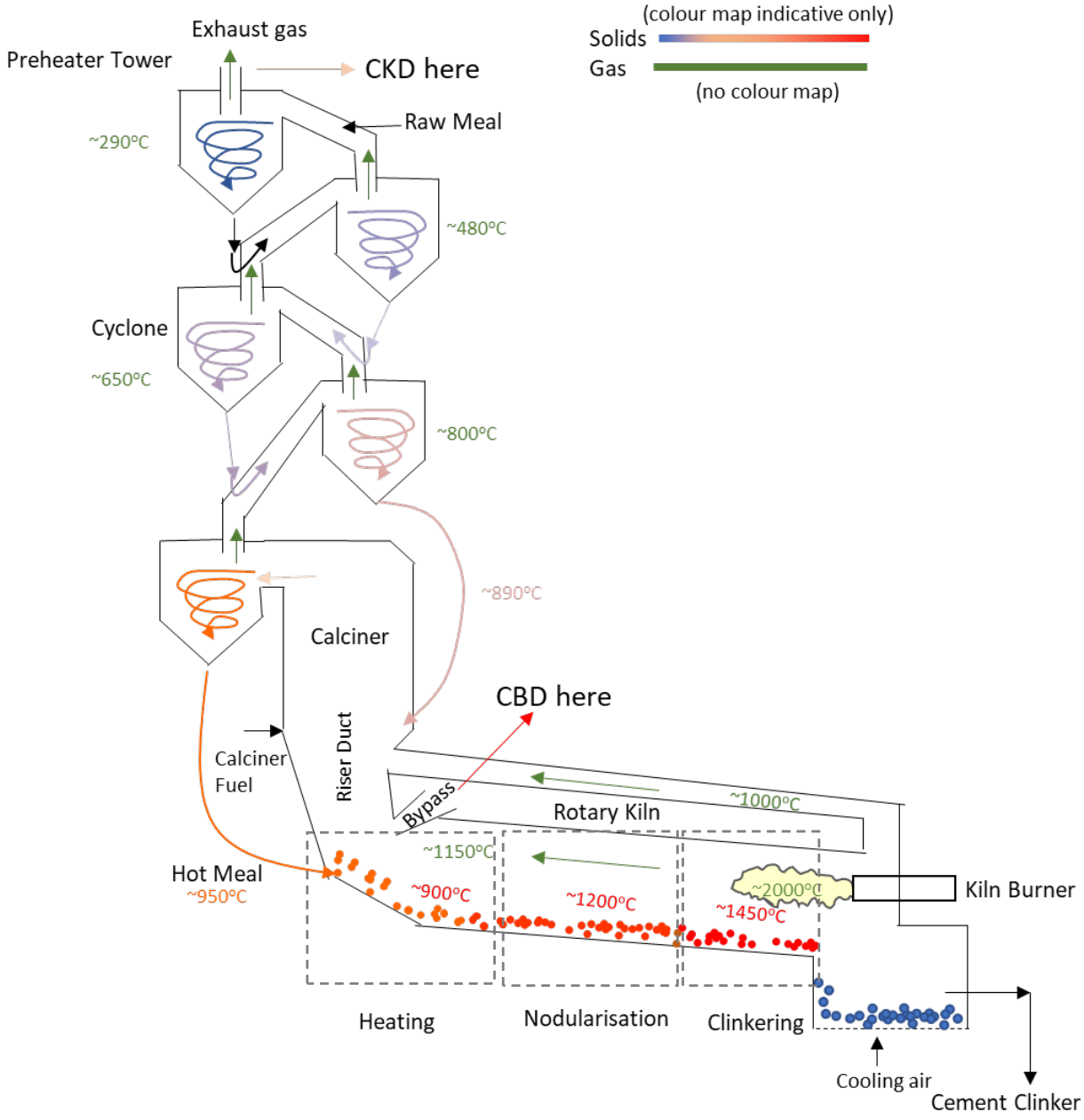

Figure 2 - Diagram of the Cement Production Process, including approximate temperatures (Fennell, Dowell, *et al.*, 2022)

Cement production in a kiln is essentially a counter-current process, with a feed comprising clay, sand, and limestone[43] being fed in through a set of cyclones, where it is progressively heated up to the temperature in the calciner, where fuel is added, before the material continues through the kiln, continuing to heat up along the way. Finally, near to the end[44], clinkering reactions take place to form a variety of calcium silicates, collectively known as clinker. The clinker then passes to a cooler, and then, when cool, on to a variety of secondary processes where it is mixed with other materials such as gypsum to produce Portland Cement. In Figure 2, two streams of note are cement kiln dust (CKD), generally recycled to the kiln and cement bypass dust (CBD), generally treated as a waste material.

Rotary kilns in the cement industry are versatile and can operate with many different types of fuel, although historically, coal has been the major fuel used. As the industry increasingly turns to alternative fuels, municipal solid waste (MSW) and refuse-derived fuels (RDFs), produced from various industrial wastes such as tyres, plastics, textiles, and sawdust, have become more common. Due to its low cost locally, natural gas is a more popular fuel in the US.

The combustion of alternative fuels other than coal has specific implications for equipment, particularly the main kiln burner, which requires the energy content of the fuel to be relatively high for stable operation. Lower calorific value fuels are generally better tolerated in the calciner than in the main kiln. All major multinational cement companies use alternative fuels.

5.2.2 Flue Gas Bulk Composition

Table 4 – Dry Process[45] Cement Plant Typical Flue Gas Composition (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	% by Mass (wet)	% by Volume (wet) [a]
CO_2 from raw material	13.3	9.1
CO_2 from burning fuel	7.9	5.4
TOTAL CO_2	21.2 (up to 33%) [b]	14.5 (up to 26%)
O_2	12.3	11.5
N_2	62.3	67.0
H_2O	4.2	7.0

[a] Calculated by authors. [b] The CO2 concentration in cement flue gas, as presented in the EU BREF, falls on the lower end of the typical range observed in cement plants. This concentration can be up to 33 % (w/w). (Bosoaga, Masek and Oakey, 2009) This variability in CO2 concentration is due to fuel type, excess air used and meal type.

There is a single emission point from a cement plant as illustrated in Figure 2 by "Exhaust gas". Table 4 details the concentrations of the bulk components in cement plant flue gas. This emission represents the combined output of gases from both the kiln and the calciner. Compared to other flue gas streams, cement flue gas has a

[43] The combination of which is often referred to as the "raw meal".
[44] Where more fuel is burned in a large burner
[45] The dry process refers to the type of cement plant used. Dry process cement plants are now the most common plant configuration.

relatively high CO_2 concentration, primarily due to the significant contribution of CO_2 from calcination of the raw material as per Equation 1. It also has a comparatively high oxygen concentration, resulting from the use of alternative fuels in the kiln and the need for their complete combustion.

5.2.3 General Emission Profile and BAT Controls

Table 5 – Cement Plant Flue Gas Pollutant Emission Concentration Survey Data Range, BAT-AEL Range, and BAT Control Technologies (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	Survey Data Range (mg/Nm³) [b]	BAT-AEL Range (mg/Nm³) [b]	BAT Control Technologies
Dust [c]	0.27-227	<10-20	Electrostatic Precipitators, Fabric Filters, and Hybrid Filters
NO_x	145-2040	<200-800	Flame Cooling, Low NO_x Burners, Staged Combustion, Mid-Kiln Firing, Mineralized Clinker, Process Optimisation, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction
SO_2	Up to 4837	<50-400	Absorbent Addition and Wet Scrubber
NH_3		<30-50[a]	
CO	200-2000	No BAT-AEL	
TOC/VOC	1-60	<10	
HF	0.009 –1.0	<1	
HCl	0.02-20.0	No BAT-AEL	
PCDD/F	0.000012 –0.27 ng I-TEQ/Nm3	<0.05-0.1 ng I-TEQ/Nm3	
Hg	0-0.03	<0.05	
∑(Cd, Tl)	0-0.68	<0.05	
∑(As, Sb, Pb, Cr, Co, Cu, Mn, Ni, V)	0.-4.0	<0.05	

[a] BAT-associated emission levels for NH_3 slip in the flue-gas when SNCR is applied. [b] Annual average. [c] The term dust is not defined in the BREF. However, these authors interpret it as FPM as CFM is uncommon in a cement application.

Table 5 summarizes the flue gas survey data, BAT-AEL ranges, and BAT control technologies described in the BREF for cement production.

A large amount of dust (cement kiln dust, CKD) is produced in the normal operation of a cement plant. This dust originates primarily from particles of limestone falling through the cyclones and is typically not highly contaminated. It can be recycled back to the plant after capture using an electrostatic precipitator and / or a baghouse filter[46].

[46] The term baghouse filter describes a filter system with a housing that contains a fibric filter in the shape of a bag. Baghouse filters capture particles primarily through mechanisms such as interception, inertial impaction, diffusion, and sieving.

One advantage of the cement process is that the finely divided limestone and the dust associated with it are excellent scrubbers of condensable pollutants and continually recycle them back to the kiln[47].

Aside from the production of dust, the major pollutant requiring engineered solutions is NO_X[48]. Methods of NO_X control in cement plants include Selective Catalytic and Non-Catalytic Reduction, and staged combustion (Hao *et al.*, 2024). Notably, the application of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) for NO_X reduction in cement plant flue gas can lead to the introduction of ammonia (NH_3) emissions as a byproduct of these control technologies. In these author's experience, SNCR is exceedingly more common than SCR for a cement application.

The choice of specific controls to achieve the stated BAT-AEL ranges typically depends on economic considerations, as well as plant-specific factors such as the type of fuel used, the composition of the raw meal, and the kiln design. Compliance with BAT-AELs is also influenced by local regulatory requirements and technical feasibility.

5.2.4 Brevik CCUS

Project Description

Brevik CCS is a full-scale carbon capture project located at Heidelberg Materials' cement plant in Brevik, Norway, and represents the company's most advanced deployment of CCS technology to date. The project is a central component of Norway's Longship initiative, a government-funded programme aimed at demonstrating the full CCS value chain from industrial capture to transport and permanent offshore storage in the North Sea.

Final investment decision for the project was granted in December 2020, and mechanical completion was achieved in December 2024. The facility is designed to capture approximately 400,000 tonnes of CO_2 per year, equivalent to roughly 50% of the plant's total process emissions. The capture system employs a post-combustion amine-based scrubbing process, supplied by SLB Capturi (formerly Aker Carbon Capture), which has been specifically adapted for the cement sector.

Existing Emissions

A request was made to Heidelberg Materials to provide recent emission concentrations for the Brevik cement plant. However, this data was not available for public

[47] Though care must be taken to ensure that there is a purge for elements, producing what is known as the cement bypass dust, CBD, otherwise they can continuously cycle round a cement plant, potentially leading to other operational problems.

[48] NO_X are produced both from nitrogen present in the fuel (fuel NO_X) and through thermal or prompt mechanisms, including the autothermal formation of NO_X via oxidation of atmospheric nitrogen at high temperatures. (Orooji et al., 2021).

consumption. Therefore, older data was extracted from SLB Capturi's[49] 2013 to 2017 pilot study at Brevik.

Table 6 – Heidelberg Materials' Brevik Plant Flue Gas Characteristics During the SLB Capturi Pilot Study (Knudsen et al., 2014)

Component	Quantity	Unit
O_2	7.5	vol%
CO_2	17.8	vol%
H_2O	18.2	vol%
N_2	56.5[a]	vol%
Dust [b]	5-10	mg/Nm^3
NO_x	180-250	mg/Nm^3
SO_2	0-130	mg/Nm^3

[a] Calculated by the authors. [b] The term dust is not defined in the study. However, these authors interpret it as FPM as CFM is uncommon in a cement application.

As shown in Table 6, the Brevik plant meets or exceeds compliance with the BAT-AEL limit for dust, NO_X, and SO_2. According to the SLB Capturi study, the plant includes the following controls to achieve these concentrations: SNCR, Electrostatic Precipitators (ESP), spray dryer flue gas desulfurization (FGD), and baghouse filters (Knudsen et al., 2014).

Due to the dated nature of the data in Table 6, concentrations were also estimated using publicly available data reported to environmental agencies. However, environmental agencies only report total emissions. Therefore, the authors of this work calculated the concentrations based on an estimated flue gas flow rate. For this reason, the concentration values should be considered estimates.

[49] Formerly Aker Carbon Capture

Table 7 - Heidelberg Materials' Brevik Plant 2023 Flue Gas Total and Estimated Concentration Pollutant Emissions (Norwegian Environment Agency, 2023)

Component	2023 Total Quantity	Unit	Concentration (mg/Nm^3) [a]
CO_2	720000	tonne	17.8 vol%
FPM	15.7	tonne	7.6
NO_x	555	tonne	269
SO_2	250	tonne	121.5
NH_3	13.4	tonne	6.5
TOC/VOC	24.8	tonne	12.0
HF	5.2	tonne	2.5
HCl	69.6	kg	0.03
Dioxins	1	g	4×10^{-7}
Hg	5.9	kg	0.003
∑(Cd, Tl)	0.18	kg	9×10^{-5}
∑(As, Sb, Pb, Cr, Cu, Mn, Ni, V)	32.0	kg	0.02
Other Inorganic	0.03	tonne	0.01

[a] Calculated by these authors by calculating the total Nm^3 emitted by dividing total CO_2 emitted by the vol% of CO_2.

Table 7 shows that PM, NO_X, and SO_2 emission concentrations for 2023 align well with the values reported by SLB Capturi in 2014. Also, all emission concentrations meet or are more than compliant with the BAT-AEL limits, except for HCl, which is reported at 2.1 compared to the limit of <1 mg/Nm^3.

5.2.5 Edmonton CCUS

Project Description

Heidelberg Materials is leading the development of the Edmonton CCUS project, located in Alberta, Canada, in collaboration with the Government of Canada and the Government of Alberta. This project aims to capture over one million tonnes of CO_2 per year from a new integrated facility comprising a cement plant and a combined heat and power (CHP) unit.

The project will employ amine scrubbing technology, using either Mitsubishi Heavy Industries' (MHI) Advanced KM CDR Process in combination with the proprietary KS-21 solvent, which was co-developed with the Kansai Electric Power Company, or Shell's Cansolv solvent system. These systems have been selected for comparison and will be adapted for application to cement flue gas.

Captured CO_2 will be compressed, transported by pipeline, and permanently stored in deep geological formations, consistent with long-term carbon sequestration practices. The facility is expected to be operational by 2026, and represents one of the first full-scale applications of post-combustion amine-based CO_2 capture in the cement sector in North America.

Existing Emissions

Table 8 - Heidelberg Materials' Edmonton Plant 2022 Flue Gas Total and Estimated Concentration Pollutant Emissions

Component	2022 Total Quantity	Unit	Concentration (mg/Nm^3) [a]
CO_2	530695	tonne	20 vol% (assumed)
$PM_{2.5}$	11.48	tonne	8.5
PM_{10}	32.08	tonne	23.7
TOTAL PM	43.56	tonne	32.2
NO_x	1710.63	tonne	1266
SO_2	157.62	tonne	116
CO	1579.81	Tonne	1169
VOCs	5.67	tonne	4.2
Benzene	1.56	tonne	1.2
Toluene	0.67	tonne	0.5
Hexachlorobenzene	10.98	g	8×10^{-6}
Dioxins and Furans	0	g TEQ	0
Hg	16.15	kg	0.01
Cd	0.27	kg	2×10^{-4}
∑(As, Sb, Pb, Cr, Co, Cu, Mn, Ni, V)	2.81	kg	0.002
Se	4.54	kg	0.003

[a] Calculated by these authors by calculating the total Nm^3 emitted by dividing total CO_2 emitted by the vol% of CO_2. As no specific CO_2 vol% is available for this plant in literature, 20 vol% was assumed.

Table 8 presents the total emissions and estimated concentrations of co-pollutant emissions as reported by Heidelberg Materials' Edmonton plant in 2022 to the Alberta Environment and Protected Areas Ministry. The PM emissions are approximately four times greater than those of Heidelberg's Brevik plant, suggesting less stringent control measures. Additionally, it is immediately apparent that the NO_X emissions exceed the EU BAT-AELs, <200-800 mg/Nm^3. Furthermore, NH_3 emissions were not reported.

5.2.6 LEILAC-2

Project Description

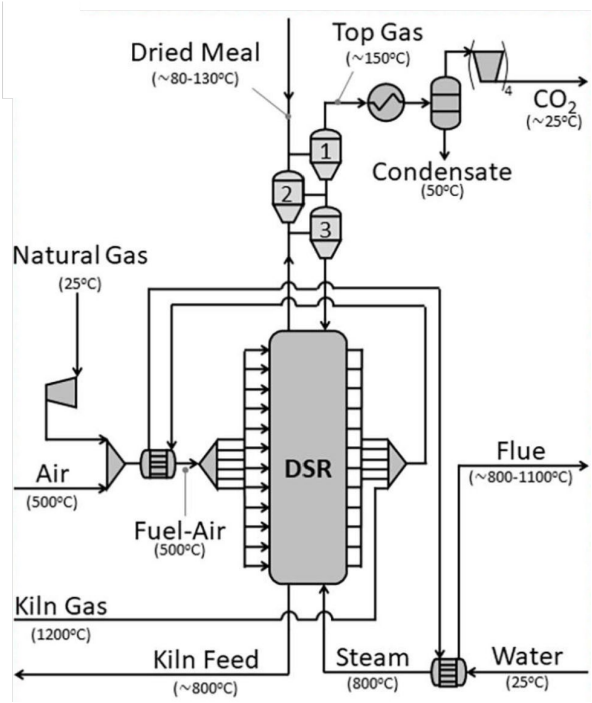

Figure 3 – The DSR process with top gas preheating and fuelled by natural gas. (Driver *et al.*, 2022)

One method to partially decarbonize a cement plant is to use a direct separation reactor as shown in Figure 3. Essentially, this is a large tube through which limestone falls, releasing CO_2 as it is heated up via heat transfer from burners external to the tube. This means that the CO_2 from calcination does not mix with air, and is produced at a high concentration, requiring only minor cleanup before compression, transport and sequestration.

The LEILAC-2 project is a partnership between Heidelberg Materials, Lhoist and Calix, as well as a number of other research and industrial institutions. It plans to construct and operate a DSR on Heidelberg Materials' site in Ennigerloh, Germany. It will capture around 100,000 tonnes of CO_2 per year[50], and the final investment decision was made in March 2022, with a FEED study published in October 2023. It is supported by a €16 million grant from the EU Horizon 2020 research and innovation program.

Existing Emissions

The LEILAC-2 project is located at Heidelberg Materials' Ennigerloh Cement Plant. Similar to the Brevik plant, exact criteria pollutant concentrations were not provided by Heidelberg Materials. Therefore, a similar calculation to the Brevik and Edmonton calculations was performed by analyzing total emissions from the year 2022.

[50] Roughly 14% of the plants CO_2 emissions (*Heidelberg Materials to cease clinker production at Hanover cement plant - Cement industry news from Global Cement*, 2025).

Table 9 - Heidelberg Materials' Hannover Plant 2023 Flue Gas Total and Estimated Concentration Pollutant Emissions (European Environment Agency, 2023b)

Component	2022 Total Quantity	Unit	Concentration (mg/Nm^3) [a]
CO_2	565000	tonne	20 vol% (assumed)
NO_x	299	tonne	203
SO_2	487	tonne	330
NH_3	69	tonne	47
CO	816	tonne	553
Benzene	4	tonne	3
Hg	11	kg	0.007

[a] Calculated by these authors by calculating the total Nm^3 emitted by dividing total CO_2 emitted by the assumed vol% of CO_2.

Table 9 presents the total and estimated concentrations of air emission co-pollutants reported to the European Environmental Agency (EEA) for Heidelberg Material's Ennigerloh plant. Particulate matter was not reported. The reported concentrations comply with the EU BAT-AEL limits. The presence of NH_3 is indicative of ammonia slip associated with SNCR, likely installed at this facility. It is also noteworthy that SO_2 emissions are approximately double those observed at the Brevik and Edmonton plants. This discrepancy may be attributed to variations in fuel composition or differences in control strategies.

5.3 Iron and Steel

Steel production is primarily carried out through two distinct routes: (1) mini-mills and (2) integrated steel mills. Globally, mini-mills account for approximately 27% of steel production, while integrated steel mills represent the remaining 73% (Steel Sector Overview | CBS Insights, 2023).

Mini-mills produce raw steel using electric arc furnaces (EAFs), fueled primarily by scrap metal, and occasionally supplemented with direct reduced iron (DRI). Their CO_2 emissions are comparatively low, typically less than 200 kilotonnes per year. In contrast, integrated steel mills rely on blast furnace–basic oxygen furnace (BF–BOF) process, which consists of a coke oven, a sintering or pelletizing plant, a blast furnace, and a basic oxygen furnace. This process can emit up to 4 million tonnes of CO_2 annually per facility.

Given their dominant market share and the magnitude of their single-point source emissions, this review focuses on the decarbonization potential of integrated steel mills.

5.3.1 Process Description

Integrated steel mills employ the blast furnace-basic oxygen furnace (BF-BOF) process. Here, iron ore is initially reduced by coke to produce "pig iron" in the blast furnace. This pig iron is then converted into liquid steel in a basic oxygen furnace, to which approximately 30 % of scrap steel can be added. Because of its high content of CO and other combustible gases, the gas exiting the blast furnace is generally burned onsite to

provide energy to the process or in a power plant. Figure 4 shows the main sources of CO_2 in an integrated steel mill prior to the implementation of CO_2 capture. The power plant is the largest single source of CO_2, but it is clear that the addition of CCS is more complex than its deployment at a cement plant, owing to the large number of significant sources of CO_2, for example from the stoves and the coke plant.

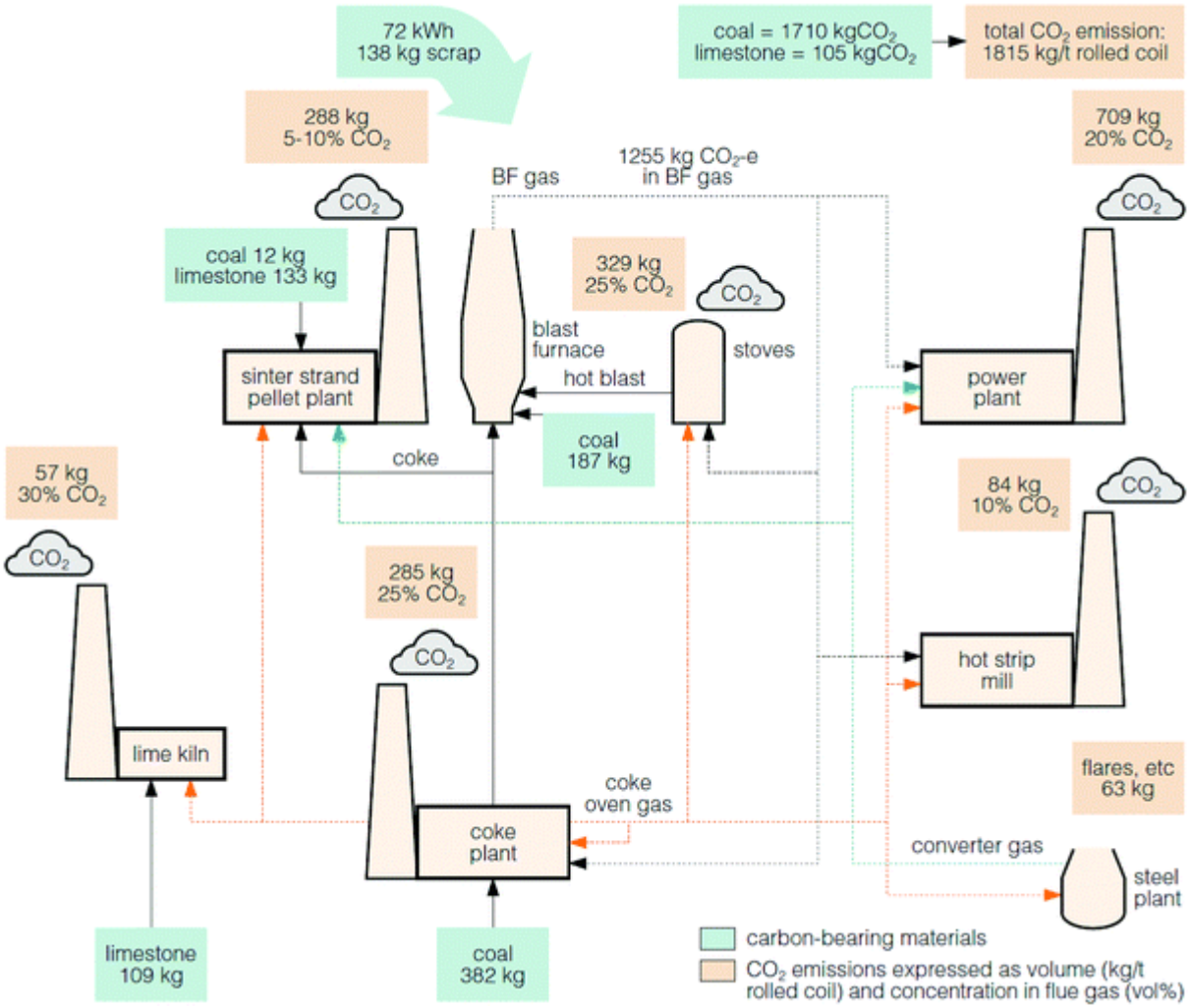

Figure 4 - CO_2 flows and main feedstocks used in the steel production process (Bui, Adjiman, *et al.*, 2018).

5.3.2 General Emission Profile and BAT Controls

As discussed in Section 5.1, the project selected for characterization in this study is the DMX Demonstration in Dunkirk (3D), which will capture CO_2 from the blast furnace gas (BFG). A detailed description of the 3D project is provided subsequently in Section 5.3.3. Unlike the PCC solvent application to cement flue gas, the blast furnace gas is not emitted to the atmosphere after CO_2 is removed. Instead, it is used as fuel gas to other processes in the steel mill as shown in Figure 4. Due to logistical constraints and the low calorific value of blast furnace gas BFG, the majority of BFG is combusted on-site, primarily in hot blast stoves and in power generation facilities, where proximity and integrated piping systems allow for efficient utilization. Therefore, BFG itself has been

characterized prior to characterizing the emissions from these downstream units where it is combusted.

Blast Furnace Gas Composition

Table 10 – Steelworks Blast Furnace Gas Composition Range (Commission of the European Union. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	Min	Max	Units
CO	19	27	vol%
H_2	1	8	vol%
CO_2	16	26	vol%
N_2	44	58	vol%
Lower Calorific Value	2600	4000	kJ/Nm^3
Dust Content [a]	0	10	mg/Nm^3
Sulphur Total	0	170	mg/Nm^3

[a] The term dust is not defined in the BREF. However, these authors interpret it as FPM.

Table 10 shows the typical composition of the bulk components of blast furnace gas. The presence of hydrogen indicates a reducing environment; thus, oxidized contaminants such as SO_2 and NO_x are not expected in this stream. Notably, there is a large portion of CO_2 and N_2 in the gas which results in a calorific value that is an order of magnitude lower than natural gas. The CO_2 concentration is relatively high compared to typical flue gases from power and heat generation, making it energetically favorable for amine-based capture.

Table 11 – Steelworks Blast Furnace Gas Contaminant Concentration Before and After Treatment (Commission of the European Union. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	Before Treatment [a]	After Treatment [a]	Unit
Dust [b]	3500-30000	1-10	mg/Nm^3
Hydrocarbons	67-250	Not Reported	mg/Nm^3
H_2S	Not Reported	14	mg/Nm^3
Cyanide Compounds (as CN-)	0.26-1.0	Not Reported	mg/Nm^3
Ammonia	10-40	Not Reported	mg/Nm^3
Benzo(a)pyrene	0.08-0.28	Not Reported	mg/Nm^3
Fluoranthene	0.15-0.56	Not Reported	mg/Nm^3
Mn	Not Reported	0.10-0.29	mg/Nm^3
Pb	Not Reported	0.01-0.05	mg/Nm^3
Zn	Not Reported	0.03-0.17	mg/Nm^3
Carbon monoxide	20-28	20-28	vol%
Carbon dioxide	17-25	17-25	vol%
Hydrogen	1-5	1-5	vol%

[a] Annual average. [b] The term dust is not defined in the BREF. However, these authors interpret it as FPM.

Table 11 shows the concentrations of contaminants in BFG before and after a common two-stage BAT control is applied. The primary purpose of this treatment is dust control. First, large particles are captured using deflectors, dry cyclones, or dust catchers and are recycled back to the sinter plant. Second, smaller particles are captured using hurdle-type venturi scrubbers or annular gas wet scrubbers. Without these controls, dust would cause operational issues and would be emitted during the combustion of BFG if flue gas controls are not implemented.

Emission Profiles and Controls

Each of the different sources of CO_2 in the steel mill will have a different composition, and a range of pollutants including PM, NO_X, and SO_X[51] are present in these flue gas streams. Particulate matter is produced in a number of locations within the plant, particularly the sintering plant and the blast furnace. However, there are also more mundane sources such as that from moving large quantities of coal and iron ore around. Trace element emissions are dominated by the basic oxygen furnace (BOF) for Sb, As, Cd, Pb, Sn and Zn, and by the blast furnace (BF) for Fe and V. A number of locations are responsible for pre-control emissions of Cu, Mn, Se and Hg (Yu *et al.*, 2023a).

NO_X emissions in integrated steelmaking arise from both fuel-bound nitrogen and thermal NO_X formation at high temperatures. In reducing environments (such as inside the coke oven and blast furnace), nitrogen in the coal is not oxidized to NO_X. Instead, it is primarily converted to ammonia (NH_3) or molecular nitrogen. These nitrogen compounds exit with the process gases, coke oven gas (COG) and BFG. This form of

[51] SO_x is a general term that refers to the family of sulphur oxides, primarily sulphur dioxide (SO_2) and sulphur trioxide (SO_3). In emissions reporting, SO_x is usually expressed as SO_2 equivalent.

nitrogen is referred to as fuel-bound nitrogen. When COG or BFG is later burned in oxidizing environments, such as hot blast stoves, coke oven heating flues, or power boilers, the NH_3 and other nitrogen species can be oxidized, forming NO_X emissions.

In contrast, thermal NO_X forms directly through the high-temperature reaction of atmospheric nitrogen with oxygen in flame zones. This is the dominant formation pathway in units such as pelletizing burners, coke oven flues, and hot blast stoves, where combustion temperatures often exceed 1,300°C. In the sintering plant, NO_X can arise from both fuel-bound nitrogen and thermal processes, as combustion occurs in a relatively oxidizing environment with long residence times (Yu et al., 2023a).

SO_X emissions in integrated steelmaking primarily arise from the sulfur content in coal and iron-bearing raw materials, including iron ore. These emissions are generated both directly, through oxidation in high-temperature processes, and indirectly, via combustion of process gases containing sulfur compounds (Bui, Adjiman, *et al.*, 2018). In the coke oven and blast furnace, which operate under reducing conditions, sulfur in the coal is primarily converted to hydrogen sulfide (H_2S) or Carbon Sulfide (COS). This H_2S is carried in the resulting coke oven gas (COG) and BFG, which are reused as fuels in other plant units. When COG and BFG are combusted in these oxidizing environments, the H_2S is converted to SO_2, forming a significant portion of total SO_X emissions in the plant.

In the sintering process, additional SO_2 is generated from both the combustion of sulfur in added coal and the oxidation or decomposition of sulfur compounds naturally present in the iron ore (e.g., sulfides and sulfates). In pelletizing, SO_2 emissions occur primarily due to the thermal decomposition of sulfur-bearing minerals within the iron ore concentrate. A smaller but direct source of SO_2 is found in the BOF, where oxygen reacts with dissolved sulfur in the hot metal during steelmaking (Bui, Adjiman, *et al.*, 2018).

For the purposes of this work, the hot blast stove flue gas and the power plant flue gas are of particular interest, as they best represent emissions associated with the combustion of BFG.

Table 12 – Steelworks Hot Stove Flue Gas Pollutant Emission Concentrations (Commission of the European Union. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	Survey Data Range (mg/Nm³) [a]	BAT-AEL Range (mg/Nm³) [b]	BAT Control Technologies
Dust [d]	<0.1-12	<10	Deflectors, Dust Catchers, Cylones, Hurdle-Type Scrubbers, Venturi Scrubbers, Annular Gas Scrubbers **for feed gas.**
NO_x	19-115	<100	
SO_x	4-154 (267-1000) [c]	<200	Desulfurization **of feed gas.**
CO	4.11-2891		
PCDD/F	0.002-0.004 (ng/Nm³)		
Hg	0.003		
∑(Cd, Tl)	0.0057 [b]		
∑(As, Sb, Pb, Cr, Co, Cu, Mn, Ni, V)	0.24 [b]		
HF	<0.08		
HCl	3 [b]		

[a] Annual average. [b] Maximum values, not annual averages. [c] Higher values of SOx emissions are noted if the fuel is a mixture of BFG and non-desulphurized COG. [d] The term dust is not defined in the BREF. However, these authors interpret it as FPM.

Table 12 presents the concentration of contaminants in hot stove flue gas. Low dust levels are observed because dust is removed prior to gas combustion, as previously discussed. Due to the low calorific value of BF gas, it is typically blended with a higher calorific value gas, such as COG, to improve combustion efficiency. When BF gas is mixed with non-desulfurized COG, this results in significantly higher SO_x emissions due to the high concentration of hydrogen sulfide (H_2S) in the COG. This can be mitigated, however, by using desulfurized COG.

The large variation in CO concentrations is attributed to the design of the hot stoves, specifically the use of internal versus external combustion chambers. Internal combustion chambers result in significantly higher CO emissions compared to external combustion chambers.

It should be noted that the Iron and Steel BREF does not specify any BATs for hot-stove flue gas, suggesting that such controls are uncommon for these emissions. This is understandable for dust and SO_2, since fuel gases are conditioned prior to combustion. However, the complete absence of controls on NO_x is unusual compared to other combustion applications described in BREF documents. The authors contend that improved control would be technically achievable and suggest that the omission may represent an oversight by regulators.

Table 13 - Steelworks Power Plant Flue Gas Pollutant Emission Concentrations (Commission of the European Union. Joint Research Centre. Institute for Prospective Technological Studies., 2013)

Component	Survey Data Range (mg/Nm^3) [a]
Dust [b]	0.8-31
NO_X	14-190
SO_2	1.1-305
CO	0.8-7.7

[a] Annual average. [b] The term dust is not defined in the BREF. However, these authors interpret it as FPM.

Table 13 shows the pollutant emission concentrations from a steelworks power plant. No additional BAT controls are recommended in the Iron and Steel BREF for dust or SO_2. This is because dust, NH_3 and H_2S are removed from the gas prior to combustion. Steelworks power plants are primarily boiler-generator arrangements that operate at lower flame temperatures, which discourages thermal NO_X formation. NO_X formation is further controlled by mixing low-calorific BF gas with higher-calorific gases to achieve lower flame temperatures.

Table 14 – Pollutant emission limits of the iron and steel industry, adapted and modified from (Yu *et al.*, 2023b)

Country	PM (mg/Nm^3)	NO_X (mg/Nm^3)	SO_2 (mg/Nm^3)
China	10	50	35
United States of America	22.9		
South Korea	20	350[a]	400[a]
EU Hot Air Stove Flue Gas	<10	<100	<200

[a] A conversion from ppmv to mg/Nm^3 has been performed by these authors.

For comparison, Table 14 presents selected BAT limits from other countries. China has established stringent targets for co-pollutant emissions, while South Korea's limits are approximately twice as high as the European Union targets as outlined in Table 12.

5.3.3 DMX Dunkirk Demonstration (3D)

Project Description

The DMX Dunkirk Demonstration (3D) project is a major European initiative aimed at demonstrating an innovative CO_2 capture technology for the iron and steel industry. Led by ArcelorMittal at its Dunkirk site in France, the project is supported by the EU Horizon 2020 programme with €14.3 million in funding. Project partners include Axens, TotalEnergies, ACP, Brevik Engineering, CMI, DTU, Gassco, IFP Energies Nouvelles (IFPEN), RWTH Aachen, and Uetikon.

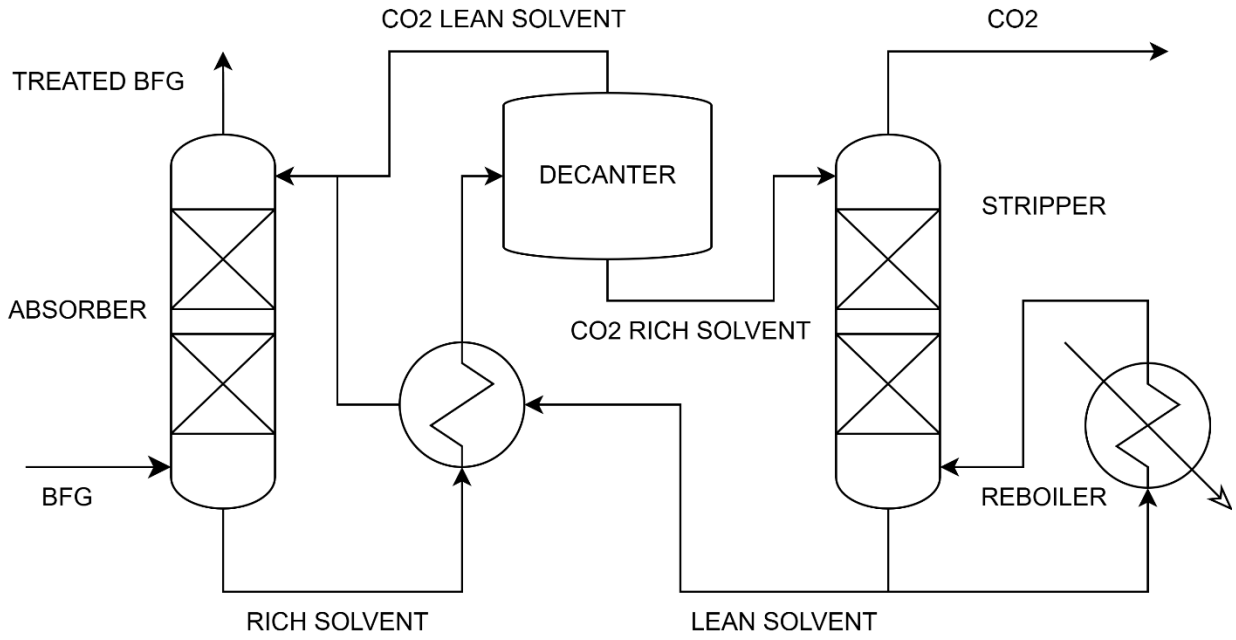

Figure 5 – Axen's DMX process applied to BFG, adapted from (Louis, 2023)

The technology at the core of the project is the DMX process, a phase-change solvent system developed by IFPEN. Unlike conventional amine-based solvents (e.g., aqueous MEA), the DMX solvent undergoes demixing into two liquid phases upon CO_2 absorption, a CO_2-rich phase and a lean phase, allowing for partial regeneration of the solvent and reducing the energy required for solvent stripping. The technology provider has claimed that the liquid-liquid separation mechanism enables significant improvements in energy efficiency, solvent stability, and operating cost, compared to traditional aqueous amines. The liquid-liquid separation occurs in a vessel called a decanter, as shown in Figure 5.

The Dunkirk pilot unit is designed to capture approximately 4,400 tonnes of CO_2 per year from BFG. The project aims to validate the technical and economic performance of DMX in this industrial context, with estimated capture costs in the range of €30–40 per tonne of CO_2. This cost range represents a notable reduction compared to conventional solvent-based systems. However, the actual capture cost of this process may increase as development continues.

Blast Furnace Gas Composition

Table 15 – ArcelorMittal Dunkirk Steelworks Blast Furnace Gas Composition (Louis, 2023)

Component	Quantity	Unit
CO	23.4	mol%
H_2	4.4	mol%
CO_2	25.0	mol%
N_2	46.9	mol%
O_2	0.3	mol%
H_2S	20	ppmv
COS	20	ppmv
Particles [a]	<25	mg/Nm^3

[a] The term particles is not defined in the BREF. However, these authors interpret it as FPM.

Table 15 shows the composition of the blast furnace gas at ArcelorMittal's Dunkirk Steelworks from an Axen presentation of DMX solvent technology. It falls comfortably within the range of the EU BERF survey data. These values were subsequently confirmed for ArcelorMittal (Morelato, 2024). According to ArcelorMittal, only PM controls were applied to the gas, aligning with what is considered best practice for blast furnace gas clean-up as stated in the EU BREF.

As shown in Table 15, the presence of H_2S and COS in the flue gas introduces an additional challenge. These species may be co-captured with CO_2 in the amine unit and, if disallowed by pipeline specifications, must be removed prior to CO_2 transport.

Emission Profiles and Controls

Emission characteristics of this particular blast gas were not available from ArcelorMittal (Morelato, 2024). However, total yearly emissions from ArcelorMittal's Dunkirk plant are reported to the European Pollutant Release and Transfer Register (E-PRTR).

Table 16 – ArcelorMittal's Dunkirk Steelworks 2023 Total Air Emissions (European Environment Agency, 2023a)

Component	2023 Total Quantity	Unit
FPM_{10}	1310	tonne
NOx	3720	tonne
SOx	4600	tonne
NH3	148	tonne
CO	86400	tonne
CH4	569	tonne
Non-Methane VOC	193	tonne
Benzene	18.5	tonne
Naphthalene	810	kg
PAHs	269	kg
HFCs	660	kg
HCl	91200	kg
PCDD/F	$2*10^{-3}$	kg TEQ
Hg	50	kg
Cd	42	Kg
∑(Pb, Cr, Cu, Ni)	2904	kg
Zn	1730	kg

Table 16 shows the total air emissions from ArcelorMittal's Dunkirk plant. Without significantly more data from ArcelorMittal, it is extremely challenging to attribute these emissions specifically to the combustion of BFG. A simple percentage-based flue gas calculation would not suffice as the necessary information on gas flows, mixing ratios, and combustion points is unavailable. Therefore, no such attempt was made by the authors. However, the total quantities are included here for completeness.

5.4 Fluidized Catalytic Cracker Emissions

5.4.1 Process Description

Refineries play a critical role in the global energy supply, converting crude oil into transportation fuels, petrochemical feedstocks, and other essential products. However, they are also significant contributors to greenhouse gas (GHG) emissions, FCC unit standing out as the single largest source of CO_2 emissions within a typical refinery. FCC units account for approximately 1% of global CO_2 emissions (Bains, Psarras and Wilcox, 2017; Güleç *et al.*, 2019; Ma *et al.*, 2023).

FCC units are responsible for producing the majority of the world's gasoline (Vogt and Weckhuysen, 2015). They process vacuum gas oil (VGO) or crude residue, upgrading these feedstocks into cracked gasoline and diesel oil. In the simplest terms, FCC units "crack" larger crude oil molecules into smaller, more usable products.

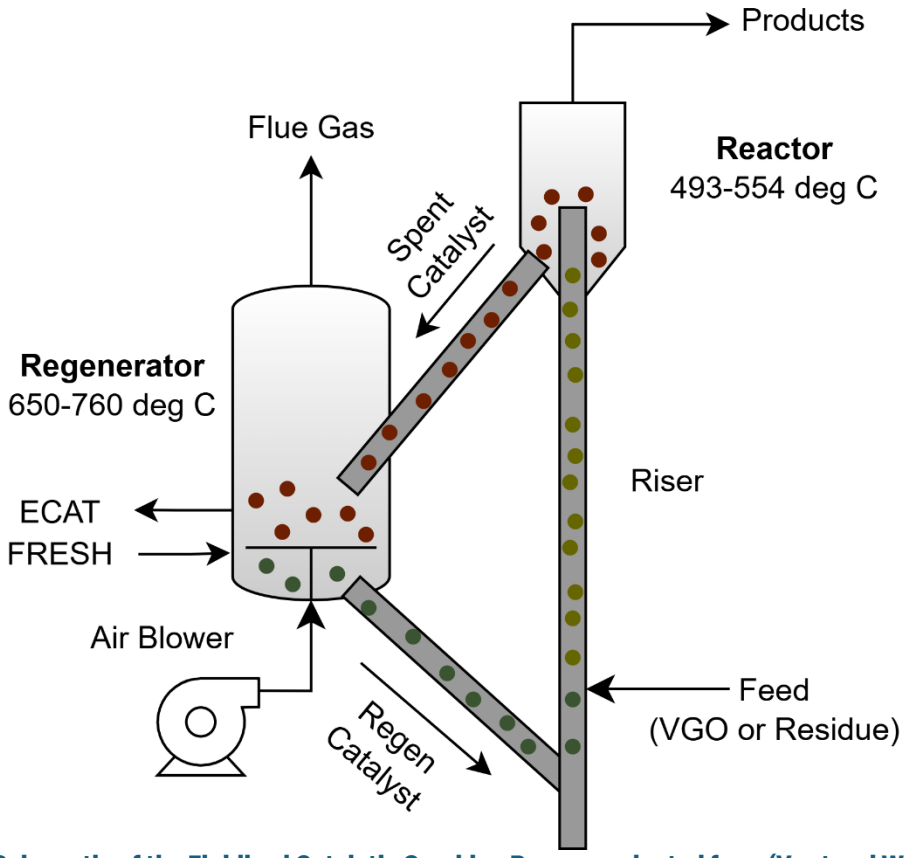

Figure 6 – Schematic of the Fluidized Catalytic Cracking Process, adapted from (Vogt and Weckhuysen, 2015)

Decarbonizing FCC emissions presents significant challenges compared to other refinery units, as CO_2 emissions cannot be mitigated through electrification or green hydrogen integration. Unlike other process units, which primarily consume energy from fuel combustion, FCC units generate CO_2 as an inherent part of the process, both through the catalytic cracking of heavy hydrocarbons and the subsequent combustion of coke deposited on the catalyst. The coke is "burned off" in a regenerator, as illustrated in Figure 6. This process also produces heat for the reactor which is required due to the endothermic nature of the process. Spent catalyst is continuously cycled to the regenerator, where the coke is systematically burned off.[52]

[52] Oxygen instead of air combustion for this application could eliminate the need for PCC processes such as an amine plant. However, this comes with the downsides of installing and operating an air separation unit.

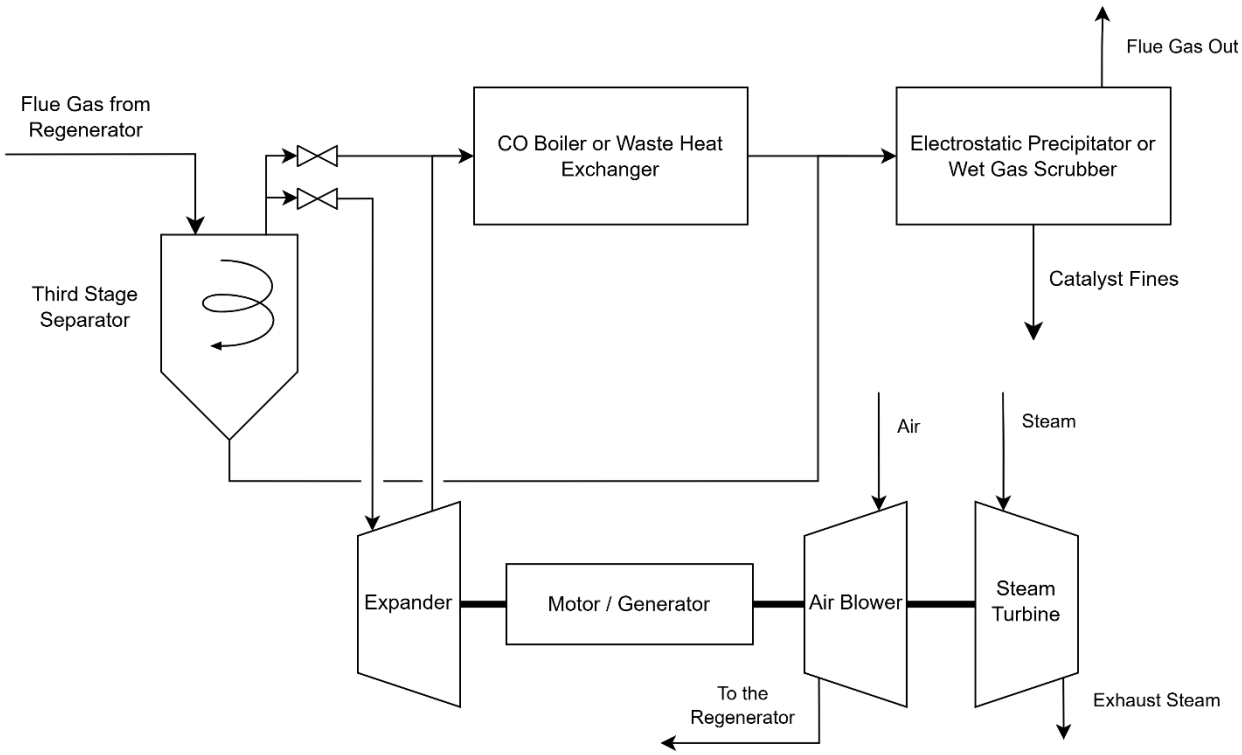

Figure 7 – FCC Flue Gas Energy Recovery Scheme, adapted from (Sadeghbeigi, 2020)

There are two modes of operation for an FCC regenerator: full combustion and partial combustion. In partial combustion mode, the complete oxidation of coke carbon is not achieved; instead, a portion of the carbon is released as carbon monoxide (CO). In this mode, CO constitutes approximately 5% to 10% of the flue gas (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2015). The CO is subsequently fully oxidized in a CO boiler, as illustrated in Figure 7.

VGO and crude residue, unless preemptively hydrotreated, typically contain significant quantities of nitrogen and sulfur. Additionally, catalyst attrition is a continuous process in FCC units, leading to the generation of FPM. As a result, NO_X, SO_2, and FPM are among the co-pollutants emitted by FCC units.

5.4.2 General Emission Profile and BAT Controls

FCC flue gas contains approximately 9.5 to 14.4% CO_2 by volume (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2015). The concentrations of the other bulk components are provided in a specific example from the Technology Center Mogstad (TCM) later in the text.[53]

[53] See Section 5.4.4

Table 17 – Catalytic Cracking Flue Gas Pollutant Emission Concentration Survey Data Range, BAT-AEL Range, and BAT Control Technologies (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2015)

Component	Survey Data Range (mg/Nm^3) [a]	BAT-AEL Range (mg/Nm^3) [a]	BAT Control Technologies
FPM [d]	15-1600	10-50 [b, e]	**Attrition-Resistant Catalyst, Low Sulphur Feedstock (Upstream Hydrotreatment),** Electrostatic Precipitator, Multistage Cyclone Separations, Third Stage Blowback Filter, Wet Scrubbing
NO_x (as NO_2)	180-700	<30 – 400 [b]	**Process Optimisation, Low-NO_x CO Oxidation Promotors, NO_x Reduction Additives,** Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low Temperature Oxidation
SO_2	320-2500	<100 – 1200 [b]	**SO_x Reduction Additives, Low Sulphur Feedstock (Upstream Hydrotreatment),** Non-Regenerative Scrubbing, Regenerative Scrubbing
NH_3	N/A		
CO	135-66000	<100	**Combustion Operation Control, Catalyst with CO Promotors,** CO Boiler
Hydrocarbon	N/A		
Aldehydes	N/A		
PAH	0.41-0.73 µg/Nm3		
Dioxins	0.002-0.03 ng TEG/Nm3		

[a] Annual average. [b] Low end of range is for new full combustion mode unit sand the higher end of the range is for existing full combustion units. [c] **Bold** controls are primary controls. [d] The BREF document uses the term PM rather than FPM. The author chose to use FPM here because the emission factors presented in the EEA air pollutant emissions inventory guidebook 2023 and Concawe, European oil refining industry's technical association, Report 4/19 exclude CPM (Hoven, Megaritis and Smithers, 2019; European Environment Agency., 2023). Therefore, it is suspected that most refineries are only reporting FPM. [e] The EU has uniquely high allowable FPM from FCCs. The NPSP standards in the US limit this to 17 mg/Nm3 @ 7% O2.

Table 17 shows the pollutant emission concentrations from an FCC. It should be noted that PM emissions are primarily composed of catalyst degradation dust with particle diameters less than 10 µm. As residue and VGO contain high concentrations of sulfur, emissions of SO_2 and SO_3 can be significant. Additionally, SO_3 aerosols further contribute to CPM formation (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2015).

The large concentration range for CO is due to varying FCC operating mode; partial or complete combustion. In complete combustion mode, CO levels in the FCC range between 50 and 1,200 mg/Nm^3. By contrast, CO boiler exhausts can maintain CO levels

below 100 mg/Nm³ (European Commission. Joint Research Centre. Institute for Prospective Technological Studies., 2015).

Primary and secondary controls are commonly applied to FCC flue gas to manage PM, NO_X, SO_2, and CO emissions. Primary controls focus on reducing pollutant formation at the source, through upstream removal of the pollutant precursors, catalyst design, or additives to the regenerator that inhibit formation. Secondary controls treat pollutants downstream, targeting the flue gas directly using equipment such as scrubbers, precipitators, or catalyst systems.

5.4.3 REALIZE Whitegate Refinery Campaign

Project Description

The REALIZE CCS project involved the demonstration of the HS-3 [54] solvent at two locations: the Irving Oil Whitegate Refinery in Cork, Ireland, and a CO_2 pilot plant in Tiller, Norway. At the Whitegate site, TNO's mobile post combustion capture miniplant, with a nominal capture capacity of 25 kg CO_2 per day, was deployed.

During the 2022 field campaign, the mobile unit was used to capture CO_2 from four different refinery stacks. The campaign included detailed characterization of the flue gas compositions from each stack, enabling a broader understanding of solvent performance under varying conditions. In parallel, the project carried out a series of technoeconomic and engineering analyses to assess the feasibility and optimization potential of the HS-3 solvent system in a refinery context.

Existing Emissions

Table 18 – Irving Oil Whitegate Refinery Flue Gas Characteristics during the HS-3 Pilot Study (Skylogianni, Grimstvedt, et al., 2022)

Component	Unit	Stack 1 (start of trial)	Stack 2 (end of trial)	Stack 2	Stack 3	Stack 4
CO_2	vol%	5.9	5.3	8.2	5.5	6.0
O_2	vol%	7.8	7.6	4.6	12.9	11.0
H_2O	vol%	1.8	2.1	4.3	4.0	3.5
CO	mg/Nm³	3.9	90.2	0.0	0.0	0,0
N_2O	mg/Nm³	0.0	0.2	0.0	0.0	0.0
NO_x	mg/Nm³	40.3	23.7	67.4	43.1	61.3
SO_2	mg/Nm³	1.1	0.0	0.0	-	-
CH_4	mg/Nm³	2.1	3.6	1.9	1.6	1.5

Table 18 shows the flue gas characteristics for the stacks tested with the HS-3 solvent. However, work package D2.1 from this study, which describes the stacks, has been deemed confidential and is not publicly available. Therefore, it is unclear if a trial on FCC flue gas was in fact performed during this research project.

[54] Solvent compositions are described in Section 6.1.2.

Table 19 – Irving Oil Whitegate Refinery 2023 Total Air Emissions (European Environment Agency, 2023c)

Component	2023 Total Quantity	Unit
NO_X	255	tonne
Non-Methane VOC	1356	tonne

Table 19 displays the data recorded by the European Environmental Agency for the Whitegate Refinery's 2023 emissions. However, the data is limited, and for the same reasons as with the ArcelorMittal steelworks, no attempt was made to attribute these emissions specifically to the FCC unit at the refinery. The data is included here for completeness.

5.4.4 AEROSOLVE / MEA-4

Project Description

The AEROSOLVE project, led by SINTEF and supported by NTNU, Uniper, TNO, Engie, and others, focused on closing knowledge gaps around aerosol emissions from CO_2 capture plants. As part of the project, TCM conducted a 3-month test campaign treating RFCC (Residue Fluid Catalytic Cracker) flue gas with MEA, under Work Package 4. These tests evaluated the performance of a conventional amine-based capture process in handling flue gas streams containing high aerosol loads.

Insights from this campaign informed the design of an optimized process configuration and enhanced online emission sampling system, which were subsequently tested during the MEA-4 campaign in Q2 2018. The results demonstrated improvements in aerosol emission control and energy efficiency (e.g., specific reboiler duty), contributing to the development of best practices for solvent-based CCS in refinery applications (Shah *et al.*, 2019).

Existing Emissions

Table 20 – TCM Fluidized Catalytic Cracker Flue Gas Characteristics (Hume et al., 2022)

Component	Quantity	Units	Concentration (mg/Nm³) [a]
CO_2	13.2	vol%, dry	
O_2	4.3	vol%, dry	
N_2 & Ar	82.5	vol%, dry	
Particulates [b]	14-41	mg/Nm³	14-41
NO	50-115	ppmv, dry	67-154
NO_2	3	ppmv, dry	6
SO_2	20-60	ppmv, dry	57-171
SO_3	7-10	ppmv, dry	25-36
NH_3	1	ppmv, dry	<1
CO	0-3	ppmv, dry	0-4
Chloride	<0.1	mg/Nm³	

[a] Calculated by these authors. [a] Particulates are not defined in the study and are assumed to be FPM.

Table 20 outlines the characteristics of TCM's fluidized catalytic cracker flue gas. All component concentrations meet or are more than compliant with the BAT-AEL limits. Notably, SO_3 is included in these characterization efforts due to its role as a nucleus for amine aerosol emissions which will discussed subsequently.

5.5 Emission Characterization Conclusions

Table 21 – Summary of Cement and Fluidized Catalytic Cracker Flue Gas PM, NO_X, and SO_2 Emission Concentrations

	Cement				Hot Stove	FCC	
Component (mg/Nm3)	**BAT-AEL**	**Brevik**	**Edmonton**	**Ennigerloh**	**BAT-AEL**	**BAT-AEL**	**TCM**
FPM	<10-20	7.6	32.2 [a]	Not Reported	<10	10-50	14-41
NO_X	<200-800	269	1266	203	<100	<30 – 400	67-154
SO_2	<50-400	121.5	116	330	<200	<100 – 1200	57-171
SO_3	N/A				N/A	N/A	25-36

[a] May contain CPM.

Table 21 summarizes the PM, NO_X, and SO_2 emissions from the facilities analyzed above. Notably, the EU BAT-AELs permit higher PM limits for FCC units compared to other industrial sources. The BAT-AEL limits for NO_X vary by sector, with cement plants having the highest allowable emissions, followed by FCC units, and then hot stoves. A similar pattern is observed for SO_2, although in this case, FCC units are permitted the highest emissions, followed by cement, and then hot stoves.

Excluding the elevated NO_X concentration observed at the Edmonton facility[55], NO_X emissions for the analyzed cement plants ranged between 200 and 300 mg/Nm³. In contrast, reported NO_X concentrations from FCC flue gas were below 200 mg/Nm³.

[55]Previously attributed to the absence of and SNCR (see Section 5.2.5)

SO_2 emissions at the Brevik and Edmonton cement plants were comparable, while emissions at Ennigerloh were significantly higher. The SO_2 concentration in FCC flue gas at TCM was consistent with the levels observed at the Brevik and Edmonton sites.

In subsequent sections, the impact of amine solvent-based post-combustion carbon capture deployment on these pollutants[56] will be discussed in detail. Notably, there is a strong degree of alignment in key criteria pollutant profiles between cement kilns and FCC units when BAT control technologies are applied. As a result, many of the insights into pollutant interactions presented in the following sections will be relevant to both flue gas sources.

One important exception to this observation is SO_3. SO_3 is a well-documented constituent of FCC flue gas, whereas it is neither routinely monitored nor reported in cement flue gas. The distinct influence of SO_3 on amine solvent emissions will be addressed in Section 6.5.2. Previous studies have shown that SO_3 concentrations in cement flue gas are low, due to the slow oxidation rate of SO_2 to SO_3 under the thermal and chemical conditions of a cement kiln. Moreover, the general industry shift from wet to dry cement production processes has reduced the moisture content of the flue gas, and since water vapor is a key factor in catalyzing SO_3 formation, this has further diminished SO_3 generation (Miller, Young and Seebach, 2002).

In contrast to the post-combustion capture projects (e.g., Brevik CCS, Edmonton CCS, and AEROSOLVE), the 3D project employed a pre-combustion CO_2 capture approach using amine solvents. As a result, PM is the only existing co-pollutant in the capture stream likely to interact with or be influenced by the capture process, since NO_X and SO_2 are not present in BFG or other syngas streams. The PM concentration reported for blast furnace gas (BFG) at Dunkirk, ranging between 0 and 25 mg/Nm³, aligns with the levels observed in cement and FCC flue gases. Therefore, the discussion in Section 6.4.1 on the impact of amine solvents on PM emissions is partially applicable to this project archetype.

However, this does not imply that criteria pollutants such as NO_X and SO_2 will remain entirely unaffected by pre-combustion capture projects. In the case of the 3D project, changes in the heating value of BFG, a result of CO_2 removal, could alter combustion conditions in downstream units, potentially influencing NO_X formation due to variations in flame temperature. Additionally, new auxiliary systems, including boilers and pumps, may lead to increased fuel or electricity demand, thereby increasing indirect emissions of NO_X and SO_2. Similar effects could also occur in the cement and iron and steel industry CCS projects described above, particularly when heat and power requirements increase due to solvent-based capture.

[56] As well as the influence of these contaminants on solvent degradation

Finally, the LEILAC-2 project will not expose co-pollutants to a solvent nor generate solvent degradation products. Moreover, technologies such as LEILAC are not expected to significantly increase heat or power demand; instead, they aim to reorganize energy use within the cement production process. Nonetheless, DSR implementation may still affect emissions of PM, NO_X, and SO_2, primarily by modifying the interaction between combustion flue gases and the raw meal. Therefore, it is important to assess whether these modifications may also lead to elevated co-pollutant emissions.

The baseline emissions from key heavy industry CCS technology archetypes have now been characterized under BAT-AEL conditions. With this foundation, the following section examines the potential impacts of CCS technologies on these emissions profiles.

6 The Impact of CCS Deployment on Co-Pollutant Emissions

6.1 Contextual Foundations

The following sections provide a concise overview of key concepts essential for understanding the interactions between amine-based carbon capture systems and co-pollutants. Topics covered include the health and environmental impacts of common co-pollutants, amine solvent formulations, mechanisms of amine degradation, measurement methodologies used at pilot capture plants, and the role of direct contact coolers (DCCs) and pre-scrubbers in flue gas conditioning. Establishing this contextual foundation is critical for the analysis of how co-pollutants may influence, or be influenced by, the deployment of amine solvent-based post-combustion carbon capture technologies.

The operation of an amine-solvent based carbon capture plant is intentionally not included in this section. Numerous resources describe in detail how these plants operate, such as (Rochelle, 2009).

6.1.1 Health and Environmental Impacts of Existing Co-Pollutants

SO_X, NO_X, and PM are major air pollutants that pose significant health and environmental risks. While SO_X and NO_X have some direct respiratory effects, their primary health hazard arises from their transformation into secondary fine $PM_{2.5}$ [57] and ozone (O_3) through atmospheric reactions. These secondary pollutants are responsible for long-term health impacts and environmental degradation.

Health Impacts

SO_X and NO_X are precursors to $PM_{2.5}$, which poses serious health risks. SO_2 oxidizes to sulfuric acid (H_2SO_4) within the atmosphere, which reacts with NH_3 to form ammonium sulfate ($(NH_4)_2SO_4$), a component of $PM_{2.5}$ (Seinfeld and Pandis, 2016). NO_X reacts with atmospheric oxidants and NH_3 to form ammonium nitrate (NH_4NO_3), another contributor to $PM_{2.5}$. (Seinfeld and Pandis, 2016). When inhaled, $PM_{2.5}$ penetrates deep into the lungs and bloodstream, leading to respiratory illnesses, cardiovascular diseases, strokes, and premature mortality (Pope Iii, 2002; *WHO Global Air Quality Guidelines*, 2021).

NO_X plays a central role in forming ground-level O_3, which is a strong lung irritant. O_3 exposure is linked to asthma exacerbation, reduced lung function, and increased hospitalizations for respiratory conditions (US EPA, 2016a).

[57] Particulate matter ≤ 2.5 μm in diameter.

Environmental Impacts

SO_X and NO_X contribute to acid rain, which acidifies lakes and rivers, and harms forests and soils. (Driscoll *et al.*, 2001). NO_X emissions drive ground-level ozone[58] formation, reducing agricultural productivity damaging native vegetation (Jacob and Winner, 2009). PM pollution leads to haze and reduced visibility. (US EPA, 2015).

Because the most severe health effects of SO_X and NO_X arise from their transformation into $PM_{2.5}$ and ozone formation, controlling these emissions is essential to reducing secondary pollution rather than just limiting direct exposure. Regulatory efforts such as the U.S. Clean Air Act and European Union air quality standards focus on reducing SO_X and NO_X to limit their secondary effects (US EPA, 2013; *EU air quality standards - European Commission*, 2025). These regulations require the implementation of the Best System of Emission Reduction (BSER) or Best Available Control Technology (BACT) in the U.S. and Best Available Techniques (BAT) in the EU for emission sources exceeding designated thresholds, ensuring that industries adopt the effective pollution control measures available.

6.1.2 Amine Solvents

Typical amine solvents in PCC applications use single or blends of alkanolamines. The following discussions will primarily focus on two alkanolamine solvents in particular: 30 wt% monoethanolamine (MEA) and CESAR1. Due to MEA's extensive history in acid gas treatment and the substantial research conducted on CESAR1, these two solvents are among the most well-understood and characterized. CESAR1 is an open-source solvent, with all research conducted on it intended to be publicly available. While various other amine blends exist, many are proprietary. In fact, all the amine solvent projects listed in Section 5 utilize proprietary solvents, and their compositions remain undisclosed.

[58] Commonly referred to as "smog"

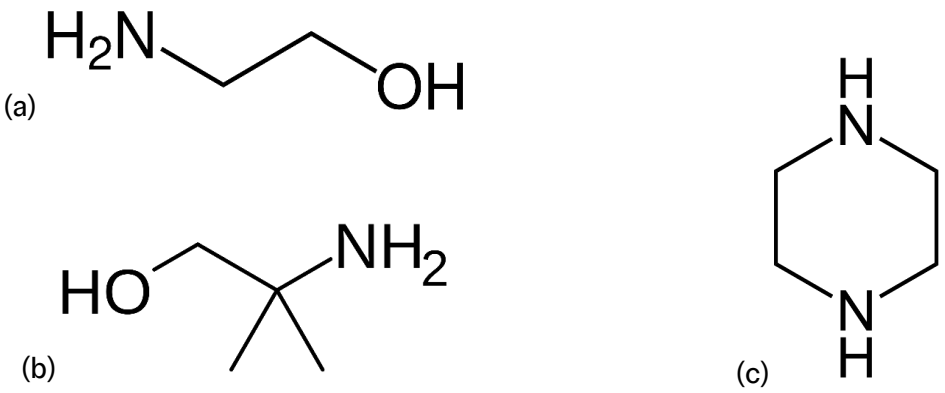

Figure 8 – The Chemical Structure of (a) MEA, (b) AMP, and (c) PZ

MEA-based solvents typically consist of a 30 wt% MEA solution, with the remainder being demineralized water. MEA is commonly classified as a first-generation (G1) solvent[59]. Its chemical structure is shown in Figure 8. As illustrated, MEA is a primary amine, meaning only one carbon atom is attached to the amine functional group (R-NH_2). MEA absorbs and releases CO_2 through the formation of carbamate or bicarbonate, as represented in Equation 2 and Equation 3. Unhindered primary and secondary amines, such as MEA, favor carbamate formation (Chowdhury *et al.*, 2013).

Equation 2 $$CO_2 + 2RNH_2 \leftrightarrow RNHCOO^- + RNH_3^+ + heat$$

Equation 3 $$CO_2 + H_2O + RNH_2 \leftrightarrow RNH_3^+ + HCO_3^- + heat$$

CESAR1 was developed during the CO_2 Enhanced Separation and Recovery (CESAR) project, sponsored by the European Union from 2008 to 2011. The project's stated objective was to develop an amine blend capable of achieving a CO_2 capture cost of €15 per ton. Although this ambitious target was not met, significant progress was made, reducing the cost of capture from €42–68 per tonne of CO_2 (MEA) to €35–55 per ton (CESAR1) in pilot-scale testing (*Final Report Summary - CESAR (CO2 Enhanced Separation and Recovery) | FP7*, 2025).[60] CESAR1 is commonly classified as a second-generation (G2) solvent.

CESAR1 is a blend consisting of 27 wt% 2-amino-2-methyl-1-propanol (AMP) and 13 wt% piperazine (PZ), with the remaining portion being demineralized water. The chemical structures of AMP and PZ are also presented in Figure 8. AMP is a primary amine similar to MEA; however, it is sterically hindered by the adjacent quaternary carbon, which causes it to form a bicarbonate, see Equation 3, and reduces the energy required for regeneration. However, this benefit comes at the cost of a slower CO_2 absorption rate. Piperazine, on the other hand, is a secondary amine, meaning its amine groups are

[59] The generational identification is not indicative of any performance metric.

[60] These values are for comparative analysis only. Actual costs of capture have been found to be significantly greater.

attached to two carbon atoms (R-NH_2-R'). Piperazine also exhibits higher loading capacity than MEA without a loss of absorption speed (Gibbins, Lucquiaud and Samson, 2024). PZ, in particular, has an exceptionally high CO_2 loading capacity due to the presence of two amine groups (-NH-). As PZ is not sterically hindered, it forms a stable carbamate when absorbing CO_2.

Tertiary amines have also been studied. The REALIZE project, referenced in Section 5.4.3, investigated an open-source solvent called HS-3, which is a blend of 15 wt% 3-amino-1-propanol (AP) and 40 wt% 1-(2-hydroxyethyl) pyrrolidine (PRLD). PRLD is a tertiary amine, characterized by three carbon atoms attached to a single nitrogen atom. Tertiary amines form only bicarbonate complexes and exhibit even higher CO_2 absorption capacities but slower absorption kinetics than secondary amines (Chowdhury *et al.*, 2013; Gibbins, Lucquiaud and Samson, 2024). PRLD was of particular interest due to its strong resistance to degradation and relatively low toxicity (Skylogianni *et al.*, 2024). However, a recent techno-economic analysis indicated that HS-3 is approximately 15% more expensive to operate than MEA (Subramani *et al.*, 2025). Consequently, future research interest in HS-3 may decline.

6.1.3 Amine Degradation

Amine degradation is a critical process in the formation of new co-pollutants. Therefore, a brief description of degradation mechanisms and known degradation behavior is included below. Buvik et al. published a review of amine degradation with a focus on pilot plant data and MEA degradation (Buvik *et al.*, 2021). Vevelstad et al. recently conducted a thorough review of amine stability with a focus on degradation mechanisms and MEA degradation (Vevelstad *et al.*, 2022).

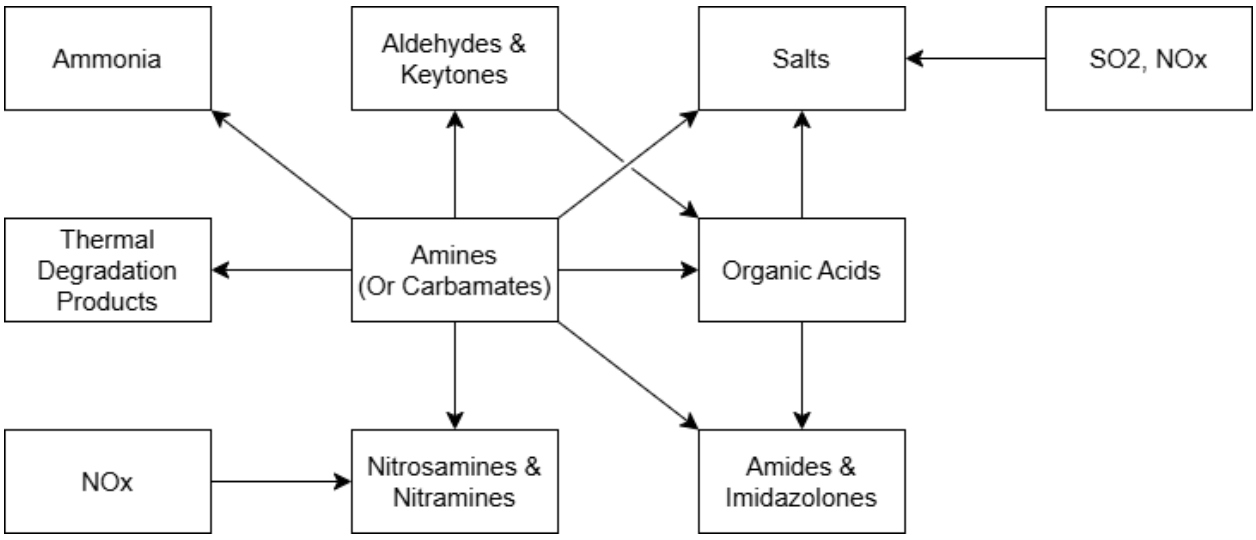

Figure 9 – Degradation pathways for aqueous primary amines, adapted from (Ghayur, Verheyen and Meuleman, 2019) with input from (Da Silva *et al.*, 2012; Vega *et al.*, 2014)

Figure 9 shows a simplified diagram of aqueous primary amine degradation pathways. The degradation of amine is broadly categorized into two primary mechanisms: (1)

oxidative degradation and (2) thermal degradation (Veltman, Singh and Hertwich, 2010; Campbell *et al.*, 2022; Vevelstad *et al.*, 2022).

Oxidative degradation occurs due to the reaction between amines and oxygen dissolved in the liquid solvent. Conversely, thermal degradation primarily results from carbamate polymerization reactions, intermolecular reactions between amine molecules at elevated temperatures (Buvik *et al.*, 2021).

It is generally believed that oxidative rather than thermal degradation is the dominant degradation pathway of amines in PCC applications (Da Silva *et al.*, 2012). In a literature review by the Scottish Environmental Protection Agency (SEPA) in 2015, it was surmised that thermal degradation accounted for 20-30% of amine degradation (SEPA, 2015). A recent modelling investigation conducted by Braakhuis and Knuutila determined that oxidative degradation accounts for approximately 80-90% of MEA degradation, with thermal degradation contributing to the remaining fraction (Braakhuis and Knuutila, 2023). Notably, the model did not incorporate the catalytic effects of corroded metals, which are known to expedite degradation processes (Léonard *et al.*, 2014a). Furthermore, the influence of oxidative degradation by-products in the solvent was not addressed.

An important aspect of amine degradation is that higher CO_2 concentrations and CO_2 loading lead to increases in both oxidative and thermal degradation (Da Silva *et al.*, 2012; Vevelstad *et al.*, 2022). Consequently, degradation is expected to be somewhat more prevalent in flue gases with elevated CO_2 concentrations, such as those from cement production (Braakhuis and Knuutila, 2023). This is in part due to the absorption reaction being exothermic. Higher CO_2 content results in the release of more heat and results in elevated absorber temperatures. In general, higher CO_2 concentrations are desirable to improve the overall energetic performance of the amine unit. However, this performance enhancement comes at the cost of increased degradation. This degradation can be mitigated, at least in part, through the implementation of intercooled amine absorption towers as shown in Figure 11.

Chi and Rochell found that dissolved iron (Fe^{2+}/Fe^{3+}) accelerated oxidative degradation of MEA to NH_3 (Chi and Rochelle, 2002). They also concluded that loaded MEA suffers oxidative degradation faster than unloaded MEA, underscoring the understanding stated in the previous paragraph. They also found that unloaded MEA is degraded in the presence of O_2 and Fe^{2+}. The presence of O_2 and Fe^{2+} generate hydroxyl radicals, via superoxide formation and Fenton reactions. It was proposed by the authors that hydroxyl radicals abstracted hydrogen from the MEA generating MEA radicals. A number of other dissolved metals have also been show to catalyze degradation (SEPA, 2015).

In addition to the (1) hydrogen abstraction mechanism proposed by Chi and Rochelle, two other amine oxidation mechanisms have been proposed in literature; (2) direct

electron abstraction from an amine by a metal, generating an amine radical and (3) intermediate organoperoxy radicals extracting hydrogens from amines (Léonard *et al.*, 2014b).

The degradation of a general primary amine by both the hydroxyl radical and organoperoxy radical mechanism is shown in Equation 4 through Equation 8. The first step is the removal of a hydrogen by a hydroxyl radical.

Equation 4 $$RCH_2NH_2 + OH^* \rightarrow RCH^*NH_2 + H_2O$$

The resulting amine radical can then absorb dissolved O_2 to form a peroxide radical:

Equation 5 $$RCH^*NH_2 + O_2 \rightarrow RC(OO^*)HNH_2$$

The organoperoxy radical then abstracts a hydrogen from a donor:

Equation 6 $$RC(OO^*)HNH_2 + RH \rightarrow RC(OOH)HNH_2 + R^*$$

The resulting hydroperoxide molecule decomposes into an imine and a hydrogen peroxide:

Equation 7 $$RC(OOH)HNH_2 \rightarrow RCH = NH + H_2O_2$$

The imine reacts with water to form NH_3 and an aldehyde.

Equation 8 $$RCH = NH + H_2O \rightarrow RCH = O + NH_3$$

As shown in the mechanism above, oxidation of primary amines results in the formation of NH_3 and aldehydes or ketones. In contrast, secondary and tertiary amines undergo oxidation to form primary amine degradation products before further oxidizing into ammonia and aldehydes or ketones (Rochelle, 2024).

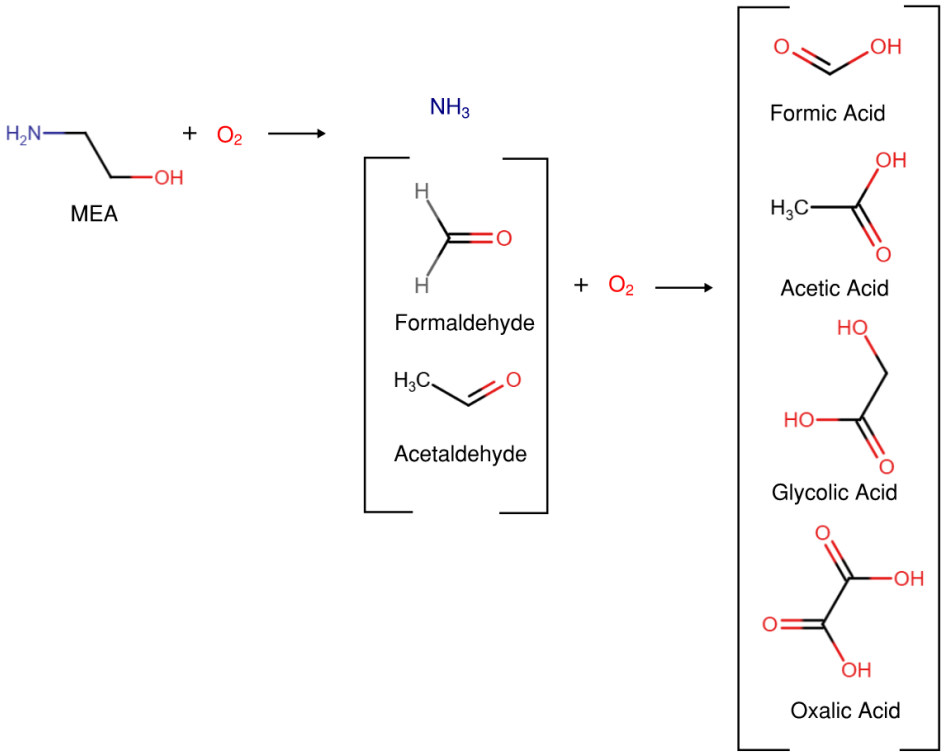

Figure 10 – The first products of MEA oxidative degradation, recreated from (Da Silva *et al.*, 2012)

A common method for quantifying MEA degradation is the measurement of organic acids including acetic, formic, oxalatic, and glycolic (Skylogianni, Veronezi Figueiredo, *et al.*, 2022). Organic acids form from the oxidation of aldehydes and ketones to their respective acid as shown in Figure 9 and Figure 10 (Vega *et al.*, 2014). The organic acids react with amines via acid-base reactions to form heat stable salts (HSS), which do not regenerate in the stripper and accumulate over time in the solvent loop. There is no common consensus on how to determine the rate of degradation and methods vary greatly between studies. Buvik et al. proposed NH_3 emissions with HSS concentration (Buvik *et al.*, 2021).

Table 22 – Amine Degradation Rates for CESAR1 and MEA at TCM, recreated from (Campbell *et al.*, 2022)

Amine Degradation	Units	NGCC Flue Gas	FCC Flue Gas
MEA	kg/tonCO_2	0.6-1.6	0.2-0.4 [a]
CESAR1	kg/tonCO_2	0.17 [b]	0.12 [c]

[a] 8% of value is due to direct amine emissions. [b] at 2.35 ppmv NO_2.

As shown in Table 22, CESAR1 is more resistant to degradation than MEA (Languille *et al.*, 2021; Campbell *et al.*, 2022; Buvik *et al.*, 2024). The reason for this resistance to degradation is attributed to AMP being sterically hindered by the quaternary carbon attached to the amine group and the ring structure of PZ improves the rigidity of the N-H bonds (Vevelstad *et al.*, 2022). Furthermore, pilot plant operators have noted that MEA has a self-accelerating degradation behavior where-as CESAR1 is linear (Moser,

Wiechers, Schmidt, Monteiro, Goetheer, Charalambous, Saleh, Van Der Spek, *et al.*, 2021).

Although initiation of the degradation is believed to be mechanistically the same as MEA degradation, the subsequent degradation mechanisms of CESAR1 are exceedingly complex. An overview of known mechanisms was written by Campbell et al. (Campbell *et al.*, 2022). However, the "major" degradation products Campbell et al. lists have already been proven to be incomplete. Very recently, >99% of all aqueous phase degradation products associated with CESAR1 were characterized (Buvik et al., 2024). The three most abundant degradation products were Ethylamine (EDA), N-(2-hydroxy-1,1-dimethylethyl)-Clycine (HMeGly), and 3,4,4-trimethyl-2-oxazolidinone (TMOX). HMeGly and TMOX were not included in Campbell et al.'s review just two years earlier. This underscores the challenges in accurately establishing all degradation mechanisms and why this continues to be an ongoing area of research.

6.1.4 Measurement of Co-Pollutants at Amine Pilot Plants

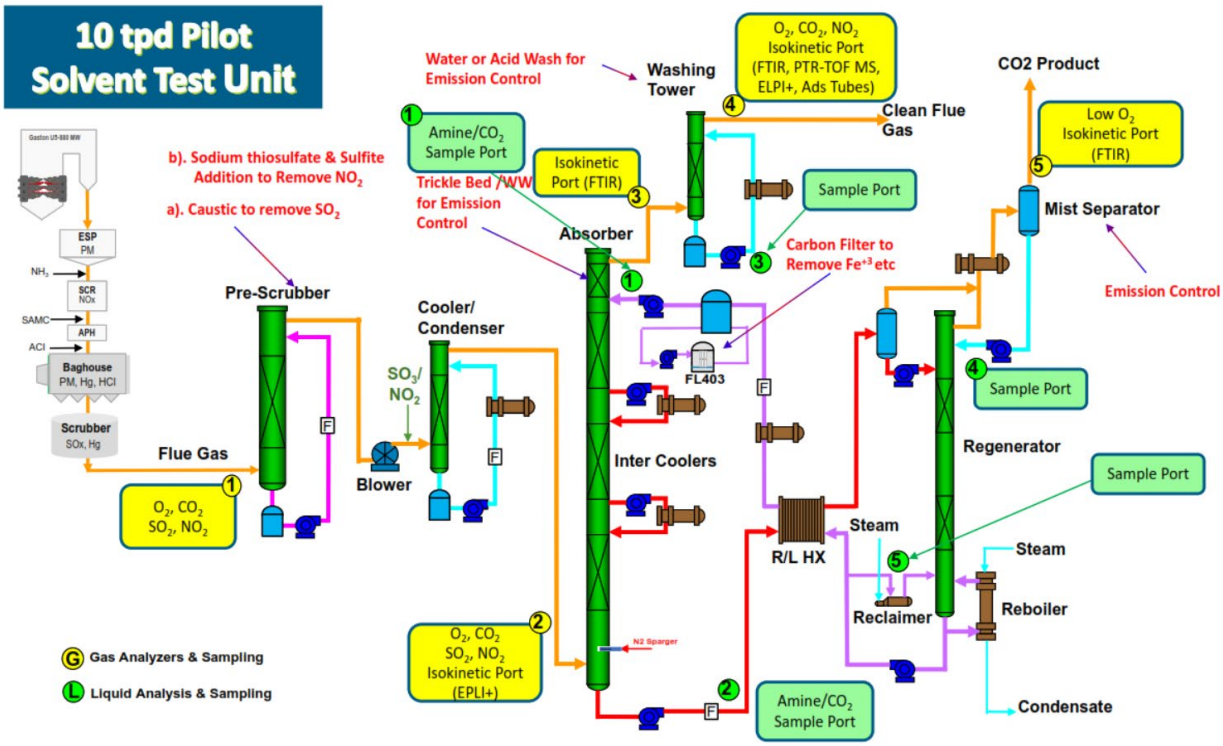

Figure 11 – Flow Diagram of the National Carbon Capture Center Pilot Solvent Test Unit with Analyzer and Sampling Locations, with permission from (Carroll, 2025)

The impact that co-pollutants have on amines and the impact amines have on co-pollutants is primarily understood through studies conducted at publicly funded research pilot plants, such as TCM's Plant and NCCC's PSTU. These pilot plants are equipped with an extensive array of analytical tools. This instrumentation enables the detailed analysis of stream compositions, including SO_2 and NO_2, entering and exiting the amine unit. Figure 11 illustrates the extensive instrumentation used for composition analysis at the NCCC pilot plants.

The most commonly employed device for determining the concentration of co-pollutants entering and exiting an amine unit in the gas phase is a Fourier Transform Infrared (FTIR) spectrometer (Buvik *et al.*, 2021). A calibrated FTIR provides real-time measurements of NO_X, SO_X, CO, CO_2, amines, NH_3, and aldehydes. Its ability to simultaneously quantify nearly all relevant co-pollutants in real time makes it an invaluable tool for research and pilot plant studies.

However, a key limitation of FTIR analysis is its detection limit, as it cannot accurately measure concentrations below 1 ppmv (Buvik *et al.*, 2021; Drewry *et al.*, 2025). If an emission has an environmental or health impact at concentrations below 1 ppmv, this measurement limitation may not be acceptable.[61] Proton transfer reaction – time-of-flight – mass spectrometer (PTR-ToF-MS) is an alternative online analytical tool with a detection limit in the range of 10 to 100 pptv (Drewry *et al.*, 2025). The drawback of this device is capital cost and the need for skilled operators (Moser, 2025; Rochelle, 2025).

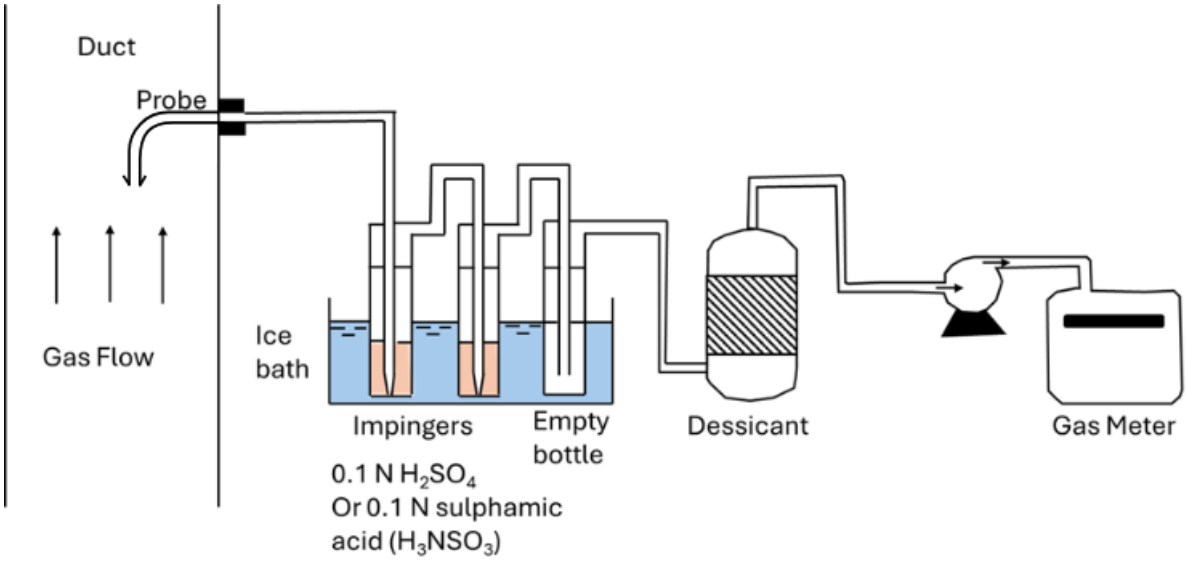

Figure 12 – Typical impinger arrangement for amine pilot plant , adapted from (Khakharia, Kvamsdal, *et al.*, 2014)

If the expense of a PTR-ToF-MS cannot be justified, a common alternative is to collect samples using impingers via isokinetic sampling via isokinetic sampling, as illustrated in Figure 12. Isokinetic sampling enables the collection of representative samples that account for the presence of both particulate and liquid phases, such as solid particles or droplets suspended in the flue gas. This is accomplished by matching the velocity and direction of the gas in the duct to that of the gas entering the sampling nozzle. For the reasons outlined in Section 6.5.2, isokinetic sampling[62] is critically important for offline measurement in PCC applications.

[61] NSAs and Nas are relevant at levels below 1 ppmv and are discussed in section 6.6.5.
[62] Opposed to a grab sample.

As shown in Figure 12, components are absorbed into the liquid-filled impingers. The liquid samples are then analyzed using analytical techniques such as liquid chromatography-mass spectrometry (LC-MS), gas chromatography-mass spectrometry (GC-MS), gas chromatography – thermal energy analysis (GC-TEA), or ion chromatography (IC), depending on the compound being measured (Morken *et al.*, 2014; Buvik *et al.*, 2021; Harvey *et al.*, 2024a).

A recent guidance document prepared by the UK National Physical Laboratory (NPL) reported a general limit of detection (LOD) of 0.2 µg/Nm³ for isokinetic liquid impingement sampling of amines and nitrosamines (NSA) in PCC applications (Harvey *et al.*, 2024a). While trialing one of the methods outlined in the document, the NPL demonstrated an LOD of 0.021 µg/Nm³ specifically for NSAs (Harvey *et al.*, 2024b). These detection limits are of the same order of magnitude as those achievable with PTR-ToF-MS.

PM particle size distributions are frequently assessed at the inlet and outlet of amine-based PCC pilot plants using instruments such as the Electrical Low Pressure Impactor (ELPI+) or other online particulate measurement devices. These methods primarily provide particle number concentrations and distributions (Beaudry, Akinpelumi and Rochelle, 2018; Saha and Anthony, 2018; Buvik *et al.*, 2021; Monteiro *et al.*, 2022). This data is useful in describing the reason for mist-phase formation and its characteristics when it exits the absorber.[63]

However, PM that is not commonly analyzed gravimetrically at the absorber outlet**.** Although, it is measured at the absorber inlet (Bade *et al.*, 2014). Instead, and, in one case, Monteiro et al. converted ELPI+ results to estimated gravimetric values by assuming spherical particles with a density of 1000 kg/m³. Gravimetric PM analysis is not typically performed at the absorber outlet in recent pilot plant studies for two main reasons: (1) when PM is an operational concern, the focus is generally on inlet concentrations, not outlet values; and (2) when PM acts as aerosol nuclei contributing to increased amine emissions[64], those emissions are quantified using alternative methods, such as ELPI+ and FTIR (Khakharia *et al.*, 2013; Beaudry, Akinpelumi and Rochelle, 2018; Monteiro *et al.*, 2022).

6.1.5 Direct Contact Coolers and Pre-Scrubbers

The direct contact cooler (DCC) is a critical component in a typical amine plant. In Figure 11, it is labeled as "Cooler/Condenser".

The DCC reduces the flue gas temperature to approximately 40 °C by quenching the incoming gas stream with lower-temperature water. This step serves two primary purposes: it helps to maintain the water balance within the amine system and enhances

[63] See Section 6.5.2.
[64] Discussed in Section 6.5.2.

CO_2 absorption efficiency. Specifically, excess water vapor is removed from the flue gas prior to entering the absorber to prevent water accumulation in the solvent loop. Additionally, lowering the gas temperature increases the solubility of CO_2 in the amine solvent, thereby improving the overall CO_2 loading capacity and efficiency of the capture process.

This unit has become highly beneficial for amine plant operators. It has been determined that chemicals can be introduced into the DCC to aid in the removal of contaminants without requiring a separate scrubber. Therefore, the term “Pre-Scrubber” is sometimes used interchangeably with DCC when it is employed for contaminant removal.

In some pilot plants, an adiabatic separate pre-scrubber is placed upstream of the DCC (Rochelle, 2024). This is the case for the NCCC pilot plant, which includes a separate scrubber before the DCC, as shown in Figure 11.

6.2 Summary of Air Emissions from Pilot Plants

Pilot Plant	Flue Gas Stream	Flue Gas SO_2 [d]		Flue Gas NO_x (NO_2) [d]		Solvent	Emission Control Configuration	1st Amine [a]	2nd Amine [a]	NH_3	CH_2O	CH_3CHO	TONO [c]	Units	Reference
		ppmv	mg/Nm3	ppmv	mg/Nm3										
CAER 0.7 MWe	Coal	<5		<50		MEA		5-1385		12-282	35-73	41-60	<LOQ	ppmv	14
Ferrybridge						RS-2							0.02	mg/Nm^3	18
Łaziska			<10			AEEA				27-50	0.11			ppmv	1
						25% AMP, 9% PZ	Single-Stage Water Wash	15-18	ND	9-12	<0.01	0.6-1		ppmv	1, 2, 21
Longannet (Aker MTU)				80-170		MEA		<4		50-80				mg/Nm^3	1
Maasvlakte						30 wt% MEA	Single-Stage Water Wash	372-460					(5 to 47) x 10^{-6}	mg/Nm^3	15
							Single Stage WW & Downstream BDU	0.97-3.95					(5 to 47) x 10^{-6}	mg/Nm^3	15
							Single-Stage Water Wash	250		10-70			(26 to 77) × 10^{-6}	mg/Nm^3	17
							Single Stage WW & Downstream BDU	1-4		10-70			(26 to 77) × 10^{-6}	mg/Nm^3	17
							Acid Wash	<1		0.75-4				ppmv	1, 2
Brindisi Power Station						MEA				14				ppm	1, 4
						KS-1		<5		<1.5				ppmv	1, 4
NCCC						MEA	Water Wash	2.14		1.74	0.0031			ppmv	3
							Acid Wash	3.02		4.75	0.0020			ppmv	3
						5 m PZ		<1						ppm	8, 1
NCCC (Aker MTU)						30 wt% MEA	Two-Stage Water Wash	10-50		10-50				ppmv (wet)	16
							ACC Control System [b]	~0		4-10				ppmv (wet)	16
						Aker Solvent	Two-Stage Water Wash	20-30		4-5				ppmv (wet)	16
							ACC Control System [b]	NR		1				ppmv (wet)	16
Niederaussem						OASE Blue	Single-Stage Water Wash	NR		NR				ppmv	1, 2
			<1		120-200	30 wt% MEA	Single-Stage Water Wash	1-8		20-40				mg/Nm^3	19
			<1		100-160		Single-Stage Water Wash [g]	70-85	3-6					mg/Nm^3	29
							Two-Stage Water Wash [g]	43-50	3-4					mg/Nm^3	29
							Single-Stage Water Wash & Dry Bed [g]	42-44	2-3					mg/Nm^3	29
							Two-Stage Water Wash & Dry Bed [g]	34-45	2-3					mg/Nm^3	29
							Single-Stage Water Wash and Acid Wash [g]	40	4					mg/Nm^3	29
							"Dry Bed Configuration" [h]	15-20	3-7	<3				mg/Nm^3	29
							Sinlge-Stage Water Wash [i]	62-64	1-3	5-7				mg/Nm^3	30
							Single-Stage Water Wash & Dry Bed [i]	0-1	0	4-5				mg/Nm^3	30
							Two-Stage Water Wash [i]	0-1	0-1	4-6				mg/Nm^3	30
							Two-Stage Water Wash & Dry Bed [i]	0	0	5-6				mg/Nm^3	30
							Single-Stage Water Wash & Acid Wash [i]	0	0-1	2-3				mg/Nm^3	30
			<1		100-180 (1-4 [j])	CESAR-1 (Fresh)	Single-Stage Water Wash	52.2-56.5	6.4-9.1	1.5-2.0				mg/Nm^3	10
						CESAR-1 (Aged)	Single-Stage Water Wash	25.4-38.0	8.1-16.4	3.3-5.3				mg/Nm^3	10
						CESAR-1 (Fresh)	Water Wash and Dry Bed	0.2	1.2	5.5				mg/Nm^3	10
Mikawa Power Plant		<5		100		TS-1	Single-Stage Water Wash	19.4						ppmv	1, 2
							Lean Cooler Improvement	5.6						ppmv	1, 2
							Improved Water Wash	0.9						ppmv	1, 2

Pilot Plant	Flue Gas Stream	Flue Gas SO_2 [d] ppmv	Flue Gas SO_2 [d] mg/Nm3	Flue Gas NO_X (NO_2) [d] ppmv	Flue Gas NO_X (NO_2) [d] mg/Nm3	Solvent	Emission Control Configuration	1st Amine [a]	2nd Amine [a]	NH_3	CH_2O	CH_3CHO	TONO [c]	Units	Reference
Fortum Oslo Varme	WtE		7.0 [f]		45.1 (1.2)	DC-103	Single-Stage Water Wash and AMD [e]	0.04-0.16						ppmv	13
Twence						MEA	Single-Stage Water Wash	750						mg/Nm^3	12
							Single-Stage Water Wash & Upstream BDU	2.5						mg/Nm^3	12
				280-300		APBS-CDRMax	Single-Stage Water Wash & Upstream BDU			<5				mg/Nm^3	20
ARC			1.5		20 (0.2)	30 wt% MEA	Two-Stage Water Wash & Dry Bed	90					< 1.6	mg/Nm^3	26
							Two-Stage Water Wash & Dry Bed (Lean Cooler Off)	15					< 1.5	mg/Nm^3	26
							Two-Stage Water Wash, Dry Bed, & Acid Wash	15					< 1.8	mg/Nm^3	26
							Two-Stage Water Wash, Dry Bed, & Acid Wash (Lean Cooler Off)	3.9					< 1.4	mg/Nm3	26
Tiller	Propane Burner	Very Low		20		MEA		<0.4		20			ND	ppm	1, 21
NCCC	NGCC (Simulated)					5 m PZ		<2						ppm	9
								0.02-1						ppmv	1, 2
							Single-Stage Water Wash	0.193		5.1	0.0105	0.0356	<0.00078	ppmv	2
							Trickle-Bed Water Wash	0.088		4.1	0.0098	0.0314	<0.00056	ppmv	2
							Trickle-Bed Only	0.0041		3.3	0.013	0.0319	<0.000458	ppmv	2
							Two-Stage Water Wash	0.057		3.0	0.0079	0.025	<0.000246	ppmv	2
							Two-Stage Acid Wash	<0.0001		0.045	0.0083	0.031	<0.00049	ppmv	2
TCM	CHP	0.043			<10	30 wt% MEA	Two-Stage Water Wash	0.0225		7.7	<0.07	0.30	<0.0008	mg/Nm^3	22
						30 wt% MEA	Two-Stage Water Wash	0.001-0.323		6.3-18	0.002-0.043	0.009-0.45	<2*10^{-6}	ppmv	23
						30 wt% MEA	Two-Stage Water Wash			20-40				ppmv	6
						S21	Two-Stage Water Wash	0.4-0.5		2.7-3.1			<0.34	mg/Nm^3	6
						S21	ACC Control System [b]	<0.012-0.023		<0.01-0.14			<0.83	mg/Nm^3	6
						S26	Two-Stage Water Wash	1.8		1.9			<0.02	mg/Nm^3	6
						S26	ACC Control System [b]	0.09		<0.01			<0.05	mg/Nm^3	6
						CESAR1	Two-Stage Water Wash	0.562	0.006					ppm	11
		Very Small		<5 (<0.5) (Dry)		CESAR1	Single-Stage Water Wash and Acid Wash	0.03-0.06	<0.007-0.01	0.02-0.04	0.0190-0.0635	0.0279-0.0931		mg/Nm^3	25
TCM	RFCC	5		60		30 wt% MEA	Two-Stage Water Wash	0-6		10-125	0-0.02	0.2-1.8		ppmv	27
		20-60 (dry) [f]		50-115 (3) (dry)		30 wt% MEA	Two-Stage Water Wash, Dry Bed, & Upstream BDU	6.63-8.15		5.25-5.91	0.05-0.08	5.70-6.55		mg/Nm^3	28
						CESAR1	Two-Stage Water Wash, Dry Bed, & Upstream BDU	0.426-0.875	0.33-0.63	3.1-3.55	0;32-0.38	0.18-0.29		mg/Nm^3	24
TCM (Aker MTU)		0-2		80		Aker Solvent	Two-Stage Water Wash & Upstream BDU	3.7	3.9					ppmv (dry)	7
							ACC Control System [b] (No Aicd Wash)	1.6	0.5					ppmv (dry)	7
Brevik (Aker MTU)	Cement		0-130 [f]		180-250	S26	ACC Control System [b]	<0.46		<4.0			<0.03	mg/Nm^3	1, 5

"<" denotes limit of detection. Other abbreviations are listed in Section 2. [a] For CESAR-1, amine 1 is AMP and amine 2 is PZ. The amines are unknown for proprietary solvents. [b] Includes one-stage water wash, one-stage acid wash, and "anti-mist" device. (Bade *et al.*, 2014) [c] This is a sum of the NSAs measured if TONO was not report. [d] Concentration at the absorber inlet unless otherwise noted. [e] AMD stands for aerosol mitigation device. It is a candle style filter analogous to a BDU. (Fagerlund *et al.*, 2021). [f] Sampled upstream of the DCC and / or amine plant specific pre-scrubbers. [g] Extracted from graphs. [h] Stated by paper's author.

Table 23 – Summary of inlet flue gas SO_X and NO_X concentrations and amine and degradation product emissions from pilot plant campaigns [1] (Buvik *et al.*, 2021); [2] (Drewry *et al.*, 2025); [3] (Dahlin *et al.*, 2013); [4] (Kamijo, Sorimachi, *et al.*, 2013); [5] (Knudsen *et al.*, 2014); [6] (Gorset *et al.*, 2014); [7] (Bade *et al.*, 2014); [8] (Akinpelumi, Saha and Rochelle, 2019); [9] (Akinpelumi, 2020); [10] (Moser *et al.*, 2025); [11] (Languille *et al.*, 2021); [12] (Monteiro *et al.*, 2022) ; [13] (Fagerlund *et al.*, 2021); [14] (Thompson *et al.*, 2017); [15] (Da Silva *et al.*, 2013); [16] (Knudsen *et al.*, 2013); [17](Khakharia, Kvamsdal, *et al.*, 2014); [18] (Fitzgerald *et al.*, 2014); [19] (Moser *et al.*, 2020); [20](Skylogianni, Veronezi Figueiredo, *et al.*, 2022); [21] (Da Silva *et al.*, 2013); [22] (Hamborg *et al.*, 2014); [23] (Morken *et al.*, 2014); [24] (Hume *et al.*, 2022); [25] (S. A. Hume *et al.*, 2021); [26](Neerup *et al.*, 2023); [27](Morken *et al.*, 2017); [28](S. Hume *et al.*, 2021); [29] (Moser, Wiechers, Schmidt, Monteiro, Goetheer, Charalambous, Saleh, van der Spek, *et al.*, 2021); [30] (Moser, Wiechers, Schmidt, Svendsen, *et al.*, 2024)

Table 23 presents a summary of amine emissions reported from various pilot plant campaigns identified during this literature review. These campaigns were conducted for a range of research objectives, and the process conditions may have had a substantial influence on the measured emissions. This table serves as a key reference and is cited throughout the report to contextualize findings related to amine release and emission control performance.

6.3 Volatile Amine Emissions

Prior to examining the impacts of amine solvents on co-pollutants, and vice versa, we first discuss volatile amine emissions. This approach is warranted because the first air-quality controls on amine units were implemented primarily to mitigate amine emissions and avoid costly solvent loss.

Before this discussion, it is essential to briefly distinguish between two types of amine emissions: those occurring in the gas phase and those manifesting as a mist due to aerosol nuclei. Only volatile amine emissions are considered in this section; emissions associated with aerosol nuclei are subsequently discussed in Section 6.5.1 because they are due to co-pollutant contamination of the flue gas.

6.3.1 Volatile Amine Emission Concentrations

Amine loss is an inherent aspect of operating an amine unit, with the magnitude of these emissions largely dependent on the control strategies[65] implemented.

In general, when identical controls are implemented, higher solvent volatility correlates with increased emissions. This trend is evident when comparing single-stage water wash[66] configurations for both MEA and CESAR1 in coal applications. MEA emissions ranged from 10 to 60 ppmv when used at the NCCC coal-fired power plant flue gas stream and reached as high as 90 ppmv at the Maasvlakte coal-fired power plant flue gas stream. In contrast, AMP emissions were 18 ppmv, while PZ emissions were 1 ppmv for CESAR1 solvent at the Niederaussem coal-fired power plant flue gas stream. Among these solvents, MEA is the most volatile, followed by AMP, with PZ being the least volatile. Furthermore, higher absorber outlet temperatures increase amine emissions due to the increased volatility of amine under elevated temperatures (Languille *et al.*, 2021).

At a minimum, solvents must contain two hydrophilic groups (Rochelle, 2024). The presence of a second hydrophilic group ensures that the solvent can be effectively captured by a water wash, even when in its carbamated form. MEA, AMP, and PZ all meet this definition as they contain 1 amine group and 1 hydroxyl group, or they contain 2 amine groups.

[65] Referred to as "emission control configurations" in the Table 23

[66] Water washes are explained in section 6.3.3.

Solvent age can also have an impact on volatile amine emissions. For example, in the single-wash configuration at the Niedaraussem pilot plant, AMP emissions were initially higher (52-57 ppm) when using fresh solvent but decreased (25-38 ppm) after the solvent had aged (Moser, Wichers, *et al.*, 2023; Moser *et al.*, 2025). The reason for this is not fully understood but Moser et al. has presented plausible theories in their 2025 paper.

Table 23 clearly shows that amine emissions from coal flue gas are higher than those from CHP or NGCC flue gas. This difference is likely due to mist-phase emissions, which will be discussed in detail in Section 6.5.2. However, with well-designed control measures, amine emissions of second generation solvents can be reduced to levels below 1 ppmv.

6.3.2 Amine Health and Environmental Impacts

Most amines used for carbon capture are considered readily biodegradable, non-bioaccumulative, and non-toxic (Brakstad *et al.*, 2023). However, amine emissions may contribute to $PM_{2.5}$ formation in the atmosphere by reacting with SO_2 and NO_2 in the same manner as NH_3, as described in Section 6.1.1 , to form amine salts (Rochelle, 2024). Additionally, they can form nitrosamines and nitramines (NAs) in the atmosphere through reactions with NO and NO_2, as discussed in Section 6.6.4. Furthermore, in regions where ecosystems are already experiencing high levels of acidification or nitrogen enrichment, approaching or exceeding their critical thresholds, additional nitrogen input from atmospheric deposition may exacerbate eutrophication and lead to habitat degradation (SEPA, 2015).

6.3.3 Downstream Volatile Amine Emission Controls

In Figure 11, three downstream control strategies are illustrated: water washes, acid washes, and dry beds (trickle beds). This section focuses exclusively on water washes, which are specifically designed to mitigate volatile amine emissions. While acid washes are generally effective at removing volatile amine emissions, they are particularly efficient at capturing NH_3 and will therefore be discussed in the Amine Degradation Products section of this report[67] . Dry beds (trickle beds), designed to remove mist-based amine emissions, will be addressed in Section 6.5.5.

Water washes[68] are an integral component of amine units, serving a dual purpose: reducing amine emissions while cooling the exiting flue gas to facilitate water recovery and maintain the unit's water balance. As such, at least one water wash stage can be expected in any amine unit installation. The recovered water is generally, although not always, returned to the absorber.

[67] Section 6.6.7

[68] Water washes flow relatively clean water counter currently against flue gas exiting an amine absorber. This interaction usually occurs across a packed bed.

The water recovered from the flue gas has a significantly lower amine concentration than the top stage of the absorber. Consequently, as the system seeks equilibrium, amines transfer from the flue gas to the aqueous phase, driven by differences in amine fugacity between the gas and liquid phases.

High-volatility amines, such as AMP and MEA, may necessitate more than a single-stage water wash (Languille *et al.*, 2021). Multi-stage water washes enhance removal efficiency by progressively reducing the amine concentration in the gas phase. Each stage captures a portion of the amines and other co-pollutants, resulting in progressively purer wash water. This approach ensures that the final wash stage reaches an equilibrium state favoring further amine absorption, thereby minimizing overall emissions.

A final control measure for mitigating volatile amine emissions is stack height, which facilitates dispersion. A well-designed stack typically provides a dilution factor between 10^{-4} and 10^{-5} (Rochelle, 2024).[69] Stack design, including flue gas exit velocity, is critical for the effective dispersion of co-pollutants.

The implementation of amine-based PCC technology will, in most cases, reduce the exhaust gas exit temperature. A lower exit temperature decreases plume buoyancy, which in turn reduces the effective stack height and limits atmospheric dispersion of residual pollutants. As a result, existing stacks that were originally designed for higher-temperature exhaust streams may no longer provide adequate dispersion performance once an amine-based PCC system is installed. To maintain compliance with ambient air quality standards, operators may therefore need to increase the physical stack height or otherwise modify the stack design to ensure equivalent dispersion of co-pollutants.

6.4 Amine Scrubbing's Impact on Existing Co-Pollutants

We now examine the direct impacts of amine scrubbing on co-pollutants, followed by a discussion of the direct effects of co-pollutants on amine solvents. In essence, this section explores how the amine unit itself influences co-pollutants in the absence of upstream control measures.

6.4.1 Particulate Matter

The terms condensable PM (CPM) and filterable PM (FPM) used in this section align with United States (US) Environmental Protection Agency (EPA) definitions. Condensable PM refers to particulate matter that exists in the gas phase at stack temperatures but condenses into liquid or solid form when cooled to ambient conditions, allowing it to precipitate out of the atmosphere. Filterable PM consists of

[69] Dilution factors at ground are a function or stack height, wind conditions, location topography, and distance from the source. The dilution factor provided by Rochelle is for a specific case.

solid or liquid particles that are emitted directly from a source and can be captured using a filter, as they do not undergo phase change at ambient temperatures.

As previously stated[70], the impact to PM on a gravimetric basis remains the least understood among all co-pollutants because gravimetric PM is not measured at the absorber.[71] However, a qualitative understanding of amine scrubbing's effect on PM can be inferred from general chemical engineering principles. Amine units typically cool flue gases to temperatures lower than those at which they would otherwise be released into the atmosphere, leading to a reduction in CPM emissions. However, since they do not cool the flue gas to ambient temperature, and since it is possible that there are kinetic limitations to the condensation, complete CPM removal cannot be assumed. Additionally, as shown in Figure 11, amine units expose flue gases to multiple water washes, including within the absorber column itself. It is therefore reasonable to assume that a portion of the FPM is captured within these units, though some fraction is expected to follow the gas-phase streamlines and remain uncaptured.

There are also references in the literature to PM removal by amine units. In pioneering work by Mitsubishi Heavy Industries (MHI), a MEA pilot plant at a coal-fired power station demonstrated that the direct contact cooler removed 40–50% of the dust in the flue gas (Iijima *et al.*, 2007). Additionally, the absorber, with a single stage of wash water, removed 40–60% of the remaining dust. The authors interpret 'dust' as filterable PM, though the paper does not explicitly clarify this distinction.

Several modelling studies have assumed that 50 wt% of particulate matter is directly removed by MEA-based amine plants (Rao and Rubin, 2002; Koornneef *et al.*, 2008; Kuramochi *et al.*, 2012). However, the basis for this assumption is not clearly documented in any of these studies.

Pilot plant studies have also demonstrated a reduction in PM. At TCM, the baseline performance evaluation of MEA on CHP flue gas included measurements of PM both before and after the amine unit (Hamborg *et al.*, 2014). PM concentrations were reduced from 0.060 mg/Nm³ to below 0.053 mg/Nm³, which corresponds to the limit of detection. CHP flue gas typically contains low levels of particulate matter, and it is important to note that the samples were collected on different days, limiting the conclusiveness of the results.

[70] See Section 6.1.4

[71] Particle size distributions are well understood.

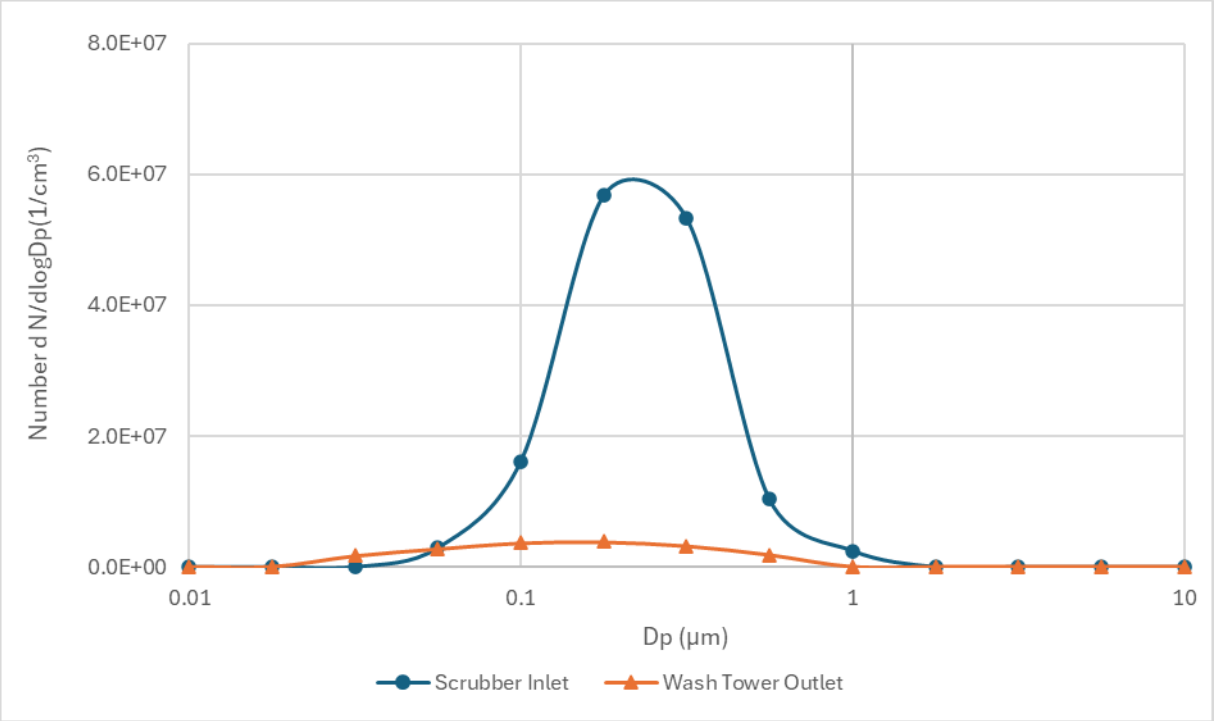

Figure 13 – ELPI+ Sampling Results for the NCCC Pilot Plant, adapted from (Saha and Anthony, 2018)

Figure 13 presents electric low-pressure impactor (ELPI) results before and after the NCCC pilot plant[72], showing that the quantity of PM at the outlet of the amine unit are lower than at the inlet. However, it is important to note that ELPI data, unless extremely carefully operated and calibrated indicate trends rather than providing precise quantitative reductions. However, is qualitatively evident that particle count decreases significantly.

[72] There are multiple pilot plants at the NCCC. The pilot plant referred to here is the 10 tpd Pilot Solvent Test Unit shown in Figure 11.

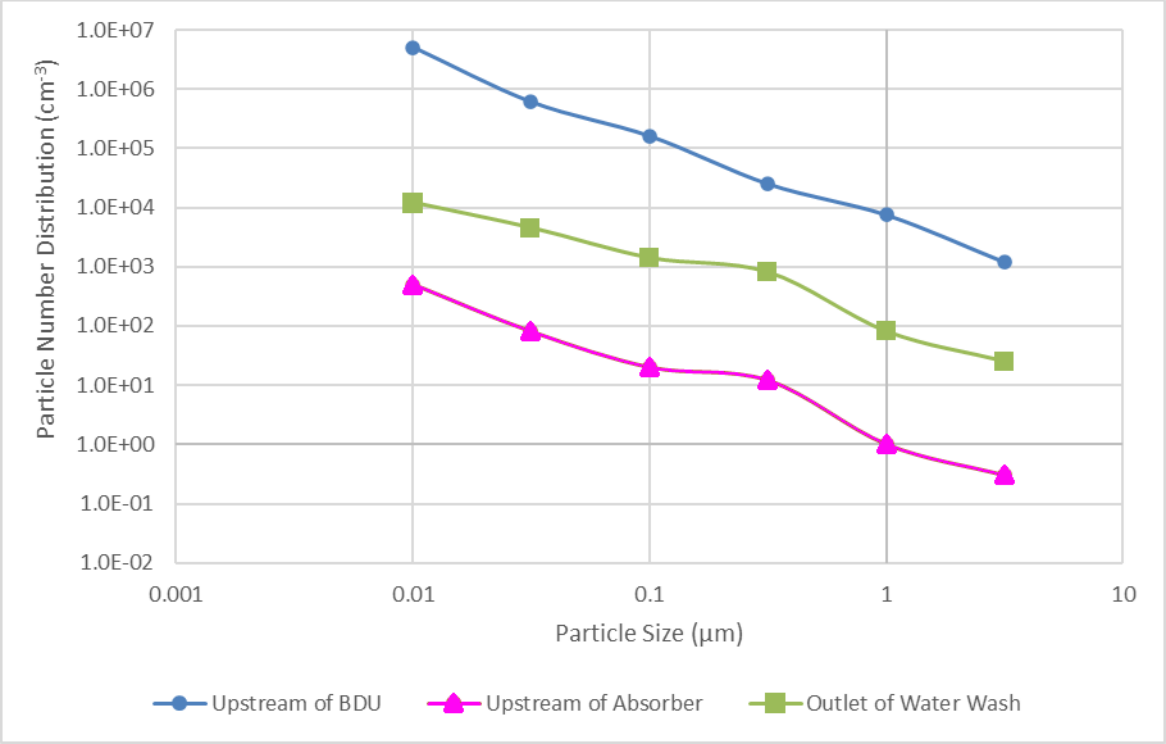

Figure 14 – ELPI+ Sampling Results for a Pilot Plant at the Twence (Monteiro *et al.*, 2022)

During the SCOPE project, trials investigating particulate matter (PM) removal upstream of the MEA amine unit using an advanced filter[73] revealed a noteworthy phenomenon. In Figure 14, the curve labeled "Upstream of Absorber" illustrates the particle size distribution of the flue gas after it passed through both the DCC and the advanced filter, but before entering the absorber. The curve labeled "Outlet of Water Wash" represents the distribution of particles exiting the absorber system. A key observation from these trials was the formation of new particles within the absorber itself. This suggests that the advanced filter was highly effective at removing PM, potentially to such an extent that conditions within the amine absorber favored the reformation of CPM.

In summary, when stringent upstream PM controls are not in place, the amine unit effectively functions as a PM removal device. Conversely, if highly effective upstream controls are implemented, the amine unit may increase PM through the formation of CPM. In the case where stringent PM controls are not in place, the formation of CPM is still possible. It is just overshadowed by the removal of PM. It is important to note, however, that these conclusions are based on the interpretation of EPLI data, rather than direct gravimetric measurements, and are therefore subject to associated limitations in accuracy and quantification.

[73] Discussed in Section 6.5.4. The advanced filter is a Brownian Diffusion Unit or BDU.

6.4.2 Nitrous Oxides

Experiments have shown that NO_2, a radical, is primarily absorbed into amine solutions via a free-radical H-abstraction from the amine, forming an amine radical and nitrite (NO_2^-). Whereas, the hydrolysis/disproportionation pathway that yields nitrite + nitrate (NO_3^-) contributes <5% under absorber conditions (Fine, 2015). NO does not react appreciably with MEA, whereas NO_2 does (Suda *et al.*, 1992). However, amine radicals can react directly with NO to form nitrosamines, a route that is generally minor when considering overall NO_x reactions with amines.

At coal-fired power plants, the reported total NO_X typically comprises approximately 95 %vol NO and 5 %vol NO_2 (Rao and Rubin, 2002). Accordingly, the concentration of NO_2 is expected to range between 0 and 5 ppmv, while the NO concentration is anticipated to be between 10 and 100 ppmv (Chen and Rochelle, 2022). Because NO_2 represents only a small fraction of the total NO_X, only a limited amount of NO_X is removed by an amine unit.

Early work by MHI demonstrated that the solvent in an MEA absorber, when fed with flue gas from a coal-fired power plant, removed between 1% and 3% of the NO_X present (Iijima *et al.*, 2007). Furthermore, modelling efforts commonly assume a 1.25% removal of NO_X within the amine unit itself (Rao and Rubin, 2002; Koornneef *et al.*, 2008; Kuramochi *et al.*, 2012). This value is derived from the assumption that 25% of the NO_2 component (which constitutes 5% of the total NO_X) is removed. Although the rationale for selecting a 25% removal rate is not provided in the referenced documents. This historical assumption may underestimate NO_2 capture. More recent experimental indicates that, for an absorber designed for ~90 % CO_2 capture, ~75 % of inlet NO_2 is absorbed in MEA, ~95 % in PZ, and >99 % in MDEA/PZ (Fine, 2015).

Pilot plant observations with mixed solvents are consistent with this picture. For the CESAR-1 system, where only NO_2 is meaningfully removed, FCC flue-gas trials at TMC showed inlet 118 ppmv NO_X upstream of the DDC resulted in an outlet concentration ranging from 107 to 117 ppmv NO_X released to the atmosphere (Hume *et al.*, 2022). This slight reduction is attributed to the reaction between NO_2 and the amine.

Once formed, nitrite (NO_2^-) behaves as a heat-stable salt (HSS) in the amine loop by pairing with protonated amine (RNH_3^+) (Skylogianni, Veronezi Figueiredo, *et al.*, 2022). And, under hot, mildly acidic stripper conditions, nitrite-derived nitrosating species (e.g., NO^+/N_2O_3) nitrosate amine (carbamate form), can form nitrosamines and release CO_2, a pathway distinct from simple salt formation (Fine, 2015; Chen and Rochelle, 2022). Because nitrosation consumes amine irreversibly, that portion of amine cannot be recovered by ordinary caustic reclaiming, unlike HSS capacity tied up by anions that can be salt-split.[74]. A discussion on the impact NO_X has on amine solvents and the

[74] Discussed in Section 6.4.4

degradation products that are formed are discussed in Section 6.5.6 and 6.6.1 respectively.

6.4.3 Sulfur Dioxide

It is well established that first and common second generation amine solvents absorb SO_2 present in the treated flue gas, resulting in the formation of HSS (Iijima *et al.*, 2007). The chemical reactions governing HSS formation in MEA are presented in Equation 9 and Equation 10.

Equation 9 $$SO_2 + H_2O + MEA \leftrightarrow MEAH^+HSO_3^-$$

Equation 10 $$MEAH^+HSO_3^- + 0.5O_2 \rightarrow MEAH^+HSO_4^-$$

HSSs do not degrade back to their respective components at temperatures below those required for thermal degradation of the amine solvent. Consequently, operators face a choice between two approaches: (1) removing SO_2 through upstream flue gas desulfurization (FGD) or (2) reclaiming the solvent. Most operators prefer the first approach, as solvent reclamation invariably leads to solvent neutralization and increased energy consumption. Due to this phenomenon, nearly all SO_2 is removed from the flue gas, and the concentration of SO_2 exiting amine units typically remains below 1 ppmv (Hamborg *et al.*, 2014; Hume *et al.*, 2022).

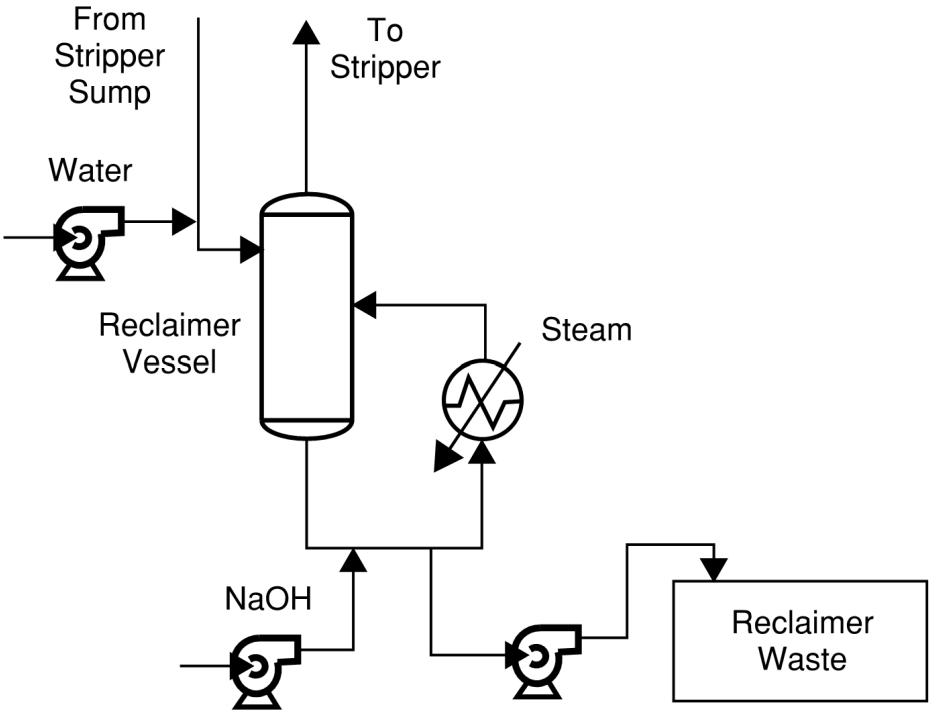

Figure 15 – TCM Reclaimer Process Flow Diagram, adapted from (Campbell *et al.*, 2022)

Even if the operator chooses to pre-emptively remove SO_2, reclaiming may be necessary. Reclaiming is an additional process used to recover amines from HSS through various methods, including thermal, chemical, and membrane-based separation techniques. Figure 15 illustrates the thermal reclaiming process employed

at TCM's plant during the ALIGN CCUS project. In this process, sodium hydroxide (NaOH) is introduced to displace the amine as the base component of the HSS[75], thereby freeing the amine. The heat supplied by steam facilitates the boiling off of amine and water, allowing their return to the stripper, while heavier by-products are collected as waste.

During the ALIGN CCUS project, this thermal reclaiming process achieved removal efficiencies of 89% for HSS, 93–95% for metals, and 82–84% for degradation products (Campbell *et al.*, 2022). Thermal reclaiming is generally expected to recover 85–95% of the amine bound in HSS (IEAGHG, 2014). Alternative reclaiming methods, such as ion exchange and electrodialysis, can remove 90% and 86–97% of HSS, respectively (IEAGHG, 2014). Furthermore, both exhibit amine losses around 1-2% of the waste stream treated.

6.5 The Impact of Existing Co-Pollutants on Amine-Based Solvents and Controls

This section examines the impacts of existing co-pollutants on amine-based solvents and the strategies available to mitigate these effects through appropriate controls. Co-pollutants can contribute to solvent degradation; however, attributing specific degradation products to individual co-pollutants is challenging. Consequently, the impacts and controls associated with degradation products are not addressed in this section but are instead explored in Section 6.6.

6.5.1 Degradation Caused by Particulate Matter

Fundamental chemical engineering principles advise against the introduction of PM into absorption columns due to the associated risk of foaming. However, foaming can typically be controlled effectively through the application of small quantities of antifoam agents (Gorset *et al.*, 2014). If chemical mitigation proves insufficient, a common next step involves installing activated carbon filters[76] or particle filters on the lean solvent return line to treat a portion of the solvent prior to its reintroduction into the absorber (Neerup *et al.*, 2023). In order to prevent foaming, these mitigation strategies are generally preferred over undertaking capital-intensive projects to install additional PM removal equipment on the flue gas.

As discussed in Section 6.1.3, it is widely recognized that metals catalyze amine degradation. It is therefore reasonable to hypothesize that fly ash or PM containing metal species may accelerate amine degradation and increase solvent emissions. This hypothesis has been validated at the laboratory scale (Da Silva *et al.*, 2013). Moreover, flue gases known to contain metal-laden PM have been associated with significantly elevated degradation rates. For instance, testing at TCM demonstrated that flue gas

[75] See Equation 9 and Equation 10

[76] If poor quality activated carbon is selected, it can lead to additional foaming (Moser, Wiechers, Schmidt, Stahl, *et al.*, 2024a).

from a FCC unit led to degradation rates 2.6 times higher than those observed with CHP flue gas (Campbell *et al.*, 2022).

Additionally, challenges in accurately measuring amine concentrations using FITR have been reported when catalyst dust accumulates on the filter surface feeding the FTIR (Bade *et al.*, 2014). Recognizing the risks posed by particulate matter, an early IEAGHG report recommended that flue gas PM concentrations be limited to below <5 mg/Nm³ (IEAGHG, 2007a). This threshold is not substantially different from the lower end of current BAT-AEL standards, which specify limits of <10 mg/Nm³ for cement kilns and hot stoves, as shown in Table 21.

6.5.2 Mist Formation

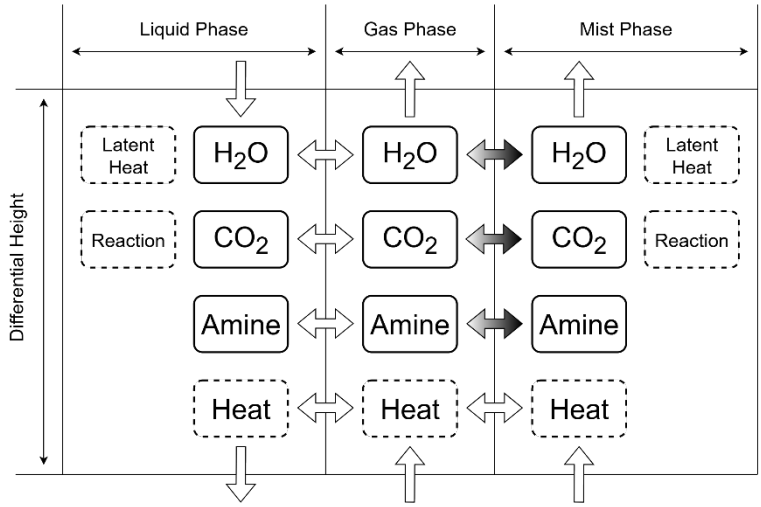

Figure 16 – MHI's Conceptual Scheme for a 3 Phase System in Amine Absorption Columns, adapted from (Kamijo, Kajiya, *et al.*, 2013)

Traditional models of amine scrubbing systems typically analyze them as vapor-liquid equilibrium systems, considering only the bulk gas and solvent phases. However, SO_3, a CPM, and sub-micron FPM can act as aerosol nuclei, facilitating the formation of an amine-laden "mist" phase[77], as illustrated in Figure 16 (Kamijo, Kajiya, *et al.*, 2013; Beaudry, Akinpelumi and Rochelle, 2018). In other words, amine solvent "sticks" to the surface of the aerosol nuclei.

As the bulk gas and entrained aerosols cool near the top of the absorber, water condenses onto the aerosol surfaces, followed by absorption of amine vapor and CO_2. These solutes lower the vapor pressure of the droplets, thereby stabilizing the aerosol phase and allowing it to persist. Figure 16 illustrates this mechanism by showing water, amine, and CO_2 preferentially partitioning into the mist phase in the upper section of the absorber.

[77] The term mist phase is less common in literature than "amine aerosol emissions". The term mist phase or mist phase emissions means amine aerosol emissions in this report.

This phenomenon does not occur with NGCC flue gas due to the absence of aerosol nuclei (Languille *et al.*, 2021). It was first identified by MHI with MEA solvent at a coal-fired power plant (Kamijo, Kajiya, *et al.*, 2013). Observations revealed that SO_3 concentrations of 0, 1, and 3 ppmv at the absorber inlet corresponded to disproportionately elevated MEA vapor emissions of 1, 30, and 68 ppmv, respectively.

Following this discovery, studies were conducted in which SO_3 and soot (carbon generated by incomplete natural gas combustion) were artificially introduced into the flue gas feeding an amine pilot plant to confirm that solid submicron particles contribute to mist-phase emissions (Khakharia *et al.*, 2013). MEA emissions increased from 46 mg/Nm^3 to 100–200 mg/Nm^3 when 10^4 to 10^6 particles per cm^3 of soot were introduced into the flue gas. Furthermore, emissions increased to 600–1100 mg/Nm^3 when 10^8 particles of H_2SO_4[78] were introduced into the flue gas.

Similar to coal-fired power plant flue gas, FCC flue gas is susceptible to mist formation. H_2SO_4 mist has been recorded at 33 mg/Nm^3 in the TCM FCC flue gas stream (Bade *et al.*, 2014). This susceptibility is evident in Table 23, which presents the TCM trials for MEA with both CHP and FCC flue gas. Initially, excessive amine emissions from the TCM pilot plant impeded its operation with FCC flue gas (Shah *et al.*, 2019). Several control measures and modifications were required, as discussed in Section 6.5.3, 6.5.4, and 6.5.5, to enable operation. These modifications reduced MEA emissions to 2 ppmv, below the 6 ppmv permit limit but still significantly higher than the 0.323 ppmv achieved with CHP flue gas at the same facility.

While second-generation solvents exhibit slightly greater resistance to this phenomenon compared to MEA, they remain susceptible (Beaudry, Akinpelumi and Rochelle, 2018). Notably, CESAR1 also experiences increased amine emissions due to mist formation (Moser *et al.*, 2025).

These mists pose significant challenges for conventional control technologies, such as water washes[79] and demisting pads[80]. Both technologies rely on impingement for aerosol removal. However, the aerosol particles are sufficiently small to follow the gas streamlines, thereby preventing effective contact with the aqueous phase or the demister surfaces designed to capture them.

As part of the SCOPE project, a model was recently developed in CO_2SIM, a SINTEF flowsheet simulator for CO_2 absorption processes. This model simulates the water and amine content as well as size changes in seven distinct aerosol droplet sizes as they enter an amine column (Moser, Wiechers, Stahl, *et al.*, 2023). When compared to experimental data from the Niederaussem pilot plant using the CESAR1 solvent, the model appears to reasonably predict mist-phase amine emissions. This tool will be

[78] The acid form of SO_3

[79] Previously discussed in Section 6.3.2

[80] Subsequently discussed briefly in Section 6.5.5

invaluable for future studies aimed at predicting amine emissions associated with the mist phase.

6.5.3 Absorber Temperature Control to Discourage Mist Formation

Some pilot plant studies have shown that increasing the lean amine temperature can reduce emissions (Shah *et al.*, 2019; Neerup *et al.*, 2023). Shah et al. (2019) explained that a larger temperature difference between the lean amine solvent entering the absorber and the gas entering the top stage induces a quenching effect, leading to both heterogeneous aerosol nuclei growth and homogeneous nucleation. In other words, the gas cools rapidly, and the resulting condensed liquid forms fine droplets rather than integrating into the bulk liquid phase at the top of the absorber. Thus, this rapid cooling leads to increased emissions. Therefore, rapid cooling of the flue gas should be avoided.

However, other studies have reported that increasing the lean temperature can actually increase emissions (Skylogianni, Veronezi Figueiredo, *et al.*, 2022). This discrepancy highlights how aerosol formation can vary significantly across systems, likely due to differences in absorber temperature profiles. In general, avoiding large temperature gradients is believed to decrease aerosol formation (IEAGHG, 2012).

There are other issues with increasing the lean amine temperature, and ultimately the absorber temperature. Increasing the absorber temperature typically results in higher specific reboiler duties (SRD) for the same CO_2 capture rate. Therefore, alternative mitigation strategies should be considered before adopting this approach.

6.5.4 Upstream Mist Phase Controls

Upstream controls may not initially appear to be a logical method for reducing amine emissions. However, they can effectively mitigate emissions by removing aerosol nuclei. One such technology is the inclusion of a baghouse filter upstream of an amine plant. During MEA testing at the NCCC pilot plant with a coal flue gas stream, the addition of a baghouse filter with lime injection reduced MEA emissions from 9 ppm to 0.5 ppm (Beaudry, Akinpelumi and Rochelle, 2018). This reduction was attributed to the neutralization of SO_3 by the lime and the subsequent collection of the resulting salts in the baghouse filter.

Prior to the installation of the baghouse filter, the particle count ranged from 10^6 to 10^7 cm^{-3} at the outlet of the water wash (Saha and Anthony, 2018). Although the post-installation particle count was not explicitly reported, an interpretation of the graphs presented in Saha and Anthony's work suggests that the count decreased to approximately 10^3 to 10^4 cm^{-3}. Baghouse filters operate based on impingement principles, allowing particles smaller than the filter's pore size to pass through. In the case of Saha and Anthony's study, this size threshold appears to correspond to particles smaller than 0.10 µm.

There is, however, a technology capable of capturing these smaller particles: the Brownian Diffusion Unit (BDU).[81] The BDU removes larger droplets and particles greater than 1–2 micrometers through inertial impaction and captures ultrafine particles, including those smaller than 0.10 µm, by taking advantage of Brownian motion (Skylogianni, Veronezi Figueiredo, *et al.*, 2022).

TNO first installed a BDU at the Maasvlakte pilot plant to remove aerosol nuclei after the flue gas exited the amine unit (Khakharia, Kvamsdal, *et al.*, 2014). In addition to impingement, the BDU utilizes diffusion by Brownian motion to capture submicron particles. The installation of the BDU at the Maasvlakte pilot plant reduced MEA emissions from a simulated NGCC flue gas stream (coal-fired power plant flue gas mixed with air) from 85–180 mg/Nm^3 to 1–4 mg/Nm^3.

Following this success, and in response to the challenges[82] associated with FCC flue gas, a BDU was subsequently installed at TCM's pilot plant between the direct contact cooler (DCC) and the absorber (Shah *et al.*, 2019). This installation aimed to capture aerosol nuclei prior to their entry into the plant. The BDU reduced the particle concentration entering the plant from an RFCC stream from approximately 10^7 to approximately 10^5 cm^{-3}.

The BDU alone proved insufficient to achieve acceptable emission levels for the FCC application at TCM. Consequently, additional measures were implemented, including reducing the temperature difference between the center of the absorber and the lean amine to discourage aerosol nucleation, as well as the addition of a dry bed (trickle bed)[83]. No details regarding the parameters used for operating the dry bed (trickle bed) at TCM have been published. A similar outcome was observed by Aker's MTU, during earlier testing of TCM FCC Flue gas (Bade *et al.*, 2014). The BDU alone achieved amine emissions of 7.6 ppm. In contrast, Aker's proprietary "anti-mist" system achieved 2.1 ppm with the BDU bypassed. No results were provided for the BDU and "anti-mist" system running simultaneously.

More recently, as part of the SCOPE project, a BDU was installed upstream of a MEA pilot plant processing flue gas at the Twence WtE facility (Monteiro *et al.*, 2022). The BDU demonstrated a separation efficiency of 99.8% to 99.98% for particle removal decrease particle counts from between 10^6 and 10^7 to between 10^2 and 10^3 [84]. During one trial, the inclusion of the BDU reduced MEA emissions from 750 mg/Nm^3 to 2.5 mg/Nm^3. One aspect of this study was the conversion of ELPI+ particle distribution data

[81] There are also high efficiency liquid/gas coalescers and turbulent spray-scrubbers available in the marketplace.
[82] Discussed in Section 6.5.2
[83] The functionality and impact of dry beds (trickle beds) are further discussed in Section 6.5.5. It should be noted that this bed at TCM is referred to as a "Third Wash Bed" rather than a dry bed (trickle bed). However, in reviewing the process flow diagram, it appears to function in the same manner as the dry beds (trickle beds) discussed in Section 6.5.5. Hence why it is referred to as a dry bed (trickle bed).
[84] See Figure 14

into total particle mass, based on the assumption that the particles were spherical and had a density of 1000 kg/m³, which is approximately the density of water. Using this approach, it was determined that the BDU reduced PM from 26 mg/m³ to 0.23 mg/m³, achieving a 99% reduction. The Aker study referenced in the previous paragraph also measured the gravimetric FPM content upstream and downstream of their BDU. They observed a reduction from 24.7–32.6 mg/Nm³ to 0.2–0.7 mg/Nm³, demonstrating a similar reduction in PM concentrations.

6.5.5 Downstream Mist Phase Controls

Unequivocally, the traditional engineering control for mist formation is the demisting pad. These pads typically consist of wire mesh that creates a tortuous path for the flue gas. This intricate pathway promotes the coalescence of mist particles into larger droplets, which subsequently collect on the wire mesh or fall out of the gas stream due to their increased mass. They are a standard feature of amine plants but have proven ineffective in fully controlling amine emissions associated with aerosol nuclei.

However, a downstream technology that has proven exceedingly effective is the dry bed (trickle bed). Dry bed (trickle bed) is patented by BASF under the tradename OASE aerozone (Barlow and Shahi, 2024). These systems have demonstrated exceptional effectiveness in controlling amine emissions associated with the mist phase (Moser *et al.*, 2025), as illustrated in Figure 17.

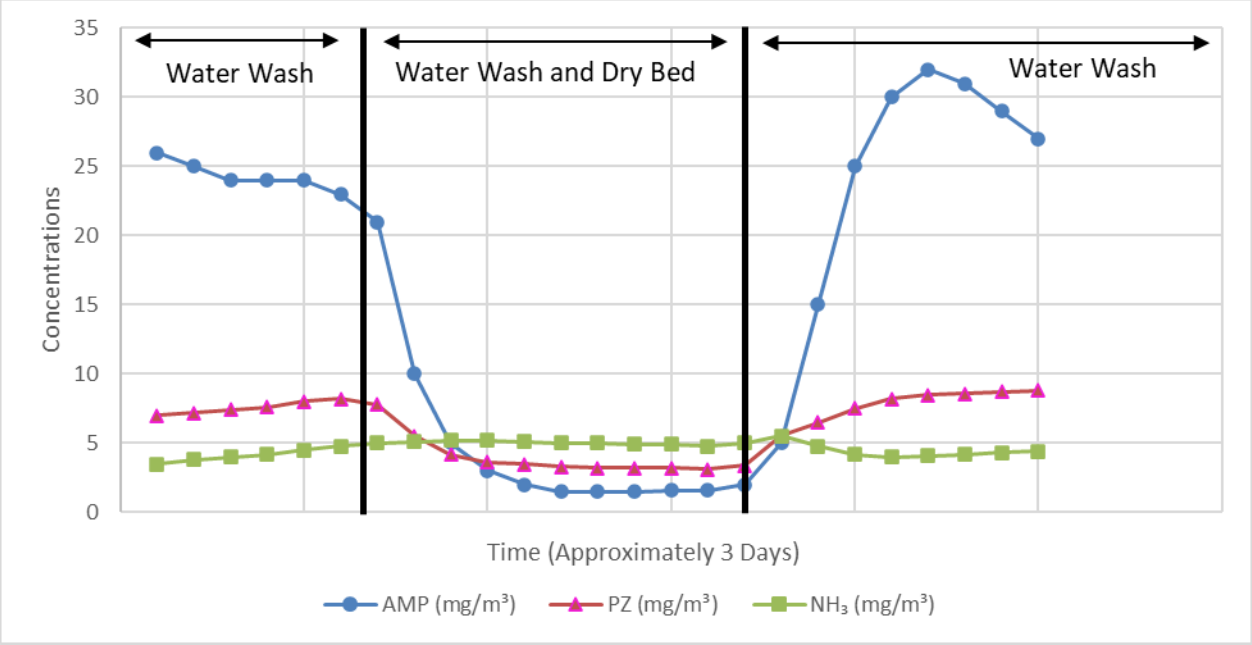

Figure 17 – Emissions of AMP, PX, and NH_3, at the Niederaussem with an aged CESAR1 solvent with an without the use of a dry bed (trickle bed), adapted from (Moser *et al.*, 2025)

A dry bed (trickle bed) consists of a packed bed that is lightly wetted with a water[85] condensed from the downstream water wash section. Its primary function is to

[85] And dilute amine

promote the growth of amine-laden aerosol particles, which are responsible for the mist phase emissions. This is accomplished by exposing these fine particles to a liquid phase composed of relatively pure water, with sufficient residence time to overcome kinetic limitations. The purity of the water provides a thermodynamic driving force for the water to condense onto the aerosol particles, facilitating their growth. Once enlarged, these particles are more readily captured by impaction in subsequent water wash stages and demister pads.

Experts frequently assert that the most effective approach to mitigating the mist problem is the removal of aerosol nuclei from the incoming gas. However, this strategy has a notable drawback: upstream control devices introduce additional pressure drop, thereby increasing the energy required to transport the gas from its origin to the amine unit. The BDU trials at TCM's Maasvlakte pilot plant demonstrated a 26–52% increase in electricity consumption, corresponding to an approximately 1–2% rise in the operational cost of capture (Khakharia, Kvamsdal, *et al.*, 2014). This disadvantage is not encountered with the dry bed (trickle bed), making it a favorable option. Nonetheless, for FCC flue gas, both technologies were ultimately required to achieve acceptable emission levels at TCM[86].

6.5.6 Degradation Caused by Nitrogen Dioxide

The impact of NO_2 on fresh amine-based solvents has been extensively studied. The method by which amine reacts with NO_2 was already described in Section 6.4.2. It has been demonstrated that MEA in particular degrades into Diethanolamine (DEA) in the presence of NO_X (Fostås *et al.*, 2011).

During the ALIGN CCUS project, which investigated CESAR1 performance with NGCC flue gas at the TCM pilot plant, several impacts of NO_2 exposure were identified (Campbell *et al.*, 2022). First, an increase in NO_2 concentration from 0.5 ppmv to 2.35 ppmv resulted in a rise in CESAR1 degradation from 0.044 kg/ton CO_2 to 0.17 kg/ton CO_2. Second, elevated NO_2 levels led to more than a fourfold increase in total nitrosamine (NSA) formation within the solvent. Whereas, MEA was found to form NSA at a negligible rate compared to CESAR1.

Secondary amines are generally considered more susceptible to NO_2-induced degradation and NSA formation than primary and tertiary amines (SEPA, 2015; Gibbins, Lucquiaud and Samson, 2024). Consequently, the degradation of CESAR1 is often attributed to its PZ content. A degradation process for PZ catalyzed by formaldehyde was proposed (Silva, Hoff and Booth, 2013). And, more recently a degradation process for the formation of mononitrosopiperazine (MNPZ) has been proposed in accordance with Equation 11 and Equation 12 (Chen and Rochelle, 2022):

Equation 11 $$NO_2 + PZ \rightarrow PZ^* + NO_2^-$$

[86] Described in Section 6.5.5

Equation 12 $NO_2^- + H^+ + PZ \rightarrow MNPZ$

The PZ radical in Equation 11 can subsequently form a peroxide radical, analogous to the process described in Equation 5 for MEA, ultimately resulting in its degradation.

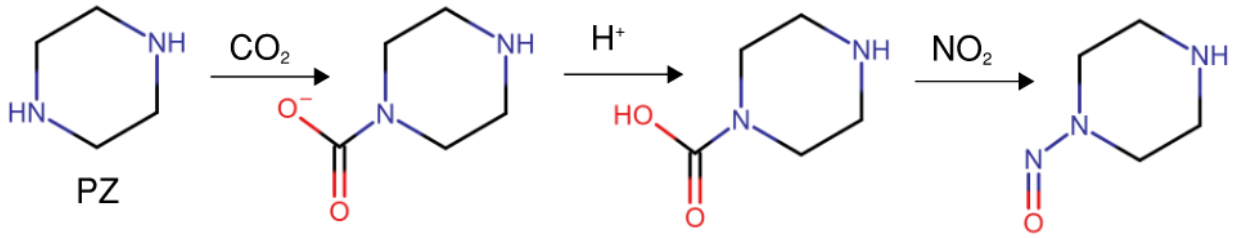

Figure 18 –MNPZ Formation for carbonated PZ, adapted from (Campbell *et al.*, 2022)

Figure 18 shows a mechanism analogous to Equation 12 for carbonated PZ. (Campbell *et al.*, 2022).

Recent studies on aged CESAR1 solvents suggest that NO_2-induced oxidative degradation may be of less concern than previously assumed. In a laboratory setting, the impact of NO_2 on PZ degradation appears to diminish as the solvent ages (Chen and Rochelle, 2022). Chen and Rochelle hypothesize that this phenomenon is attributable to the accumulation of aldehydes within the solvent. Aldehyde autoxidation can generate a substantial number of radicals, which may overshadow those produced by NO_2.

The observation that aged solvent reduces the PZ degradation rate is potentially corroborated by pilot plant studies conducted at the Niederaussem coal power plant. When NO_2 entering the absorption column was decreased from 2-5 mg/Nm^3 to <1 mg/Nm^3 by flue gas per-treatment, for an aged CESAR1 solvent (>20,000 hours) no impact was observed on ammonia emissions or NSA concentrations within the solvent (Moser, Wiechers, Schmidt, Stahl, *et al.*, 2024b). However, paradoxically, the decrease in NO_2 entering the absorption column actually accelerated the rate of acid number increased along with main oxidative degradation products (e.g. formate, acetate, etc.) (Moser, Wiechers, Schmidt, Figueiredo, *et al.*, 2023) and the thermal degradation product formylpiperazine, all indicators of solvent degradation. Based on this finding, Moser et al. (2024) concluded that degradation products induced by NO_2 may, in fact, confer a protective effect against further solvent degradation. These observations warrants further investigation, as they may suggest that NO_2-specific emission control measures upstream of an amine plant do not improve solvent life.

6.5.7 Upstream Nitrogen Dioxide Control

One method for eliminating NO_2 from the flue gas feed involves adding thiosulfate ($S_2O_3^{2-}$) or emulsified sulfur, which reacts with sulfite to form thiosulfate, to the wash water in the DCC or a dedicated pre-scrubber (Sapkota, Fine and Rochelle, 2015; Suresh Babu, 2019; Moser, Wiechers, Schmidt, Stahl, *et al.*, 2024b). Sulfite absorbs NO_2 by converting it to nitrite, as shown in Equation 13.

Equation 13 $NO_2 + SO_3^{2-} \rightarrow NO_2^- + SO_3^{\bullet-}$

In the presence of oxygen, the sulfite radical formed in Equation 13 undergoes a series of radical propagation reactions, ultimately depleting sulfite from the solution. However, when thiosulfate is introduced, it competes with sulfite in these radical reactions, effectively preserving sulfite concentrations and enhancing the reaction described in Equation 13. This method of NO_2 removal has been validated by comparing NO_2 concentrations before and after the DCC with thiosulfate dosing (Moser, Wiechers, Schmidt, Stahl, *et al.*, 2024b). Furthermore, Selinger demonstrated with a pilot study at the NCCC that 80 to 95% of NO_2 can be removed by introducing thiosulfate to a dedicated pre-scrubber (Selinger, 2018). However, some researchers suggest that NO_2 may still form within the absorber due to the presence of NO and O_2 (Chen and Rochelle, 2022).

SCRs and SNCRs are both technologies used for NO_X reduction. These technologies remove both NO and NO_2. Both technologies rely on NH_3 injection[87] to reduce NO_X to N_2 and water. SCR systems operate at significantly lower temperatures (250-400 °C) compared to SNCR systems (850-1050 °C) (EPA, 2025c, 2025b). However, SCR achieves this reduction at lower temperatures by passing the NH_3 and flue gas across a catalyst bed, which enhances the reaction efficiency. The ability of SCR to achieve high reduction efficiency at relatively low temperatures stems from the use of a catalyst, which facilitates the reaction between NH_3 and the flue gas. SCR systems can achieve up to 95% reduction efficiency (Heck, 1999). In contrast, vendor data indicate that SNCR systems achieve reductions of approximately 20–70%, with cement applications typically at the lower end of this range (*NOx reduction with SCR, SNCR and Scrubber methods*, 2025).

It should be noted that the use of SCR systems results in ammonia slip to the atmosphere. Operators therefore attempt to optimize their systems to balance regulatory compliance with the minimization of ammonia emissions. SCR systems are unquestionably a mature and proven technology. In natural gas power generation applications, they are highly effective and can reliably reduce NO_x concentrations to below 2 ppmv. However, in certain industrial applications, SCR implementation can be more challenging due to site-specific constraints, such as space limitations, flue gas characteristics, or integration complexity. In addition, the capital and operating expenditures associated with SCR installation and operation may not always be economically justified for these applications.

6.5.8 Upstream Sulfur Dioxide Control

The importance of SO_2 removal before entry into the amine unit is discussed in detail in Section 6.4.3. FGD units are considered a BAT control for most flue gas streams containing SO_2 and can effectively reduce SO_2 concentrations before the gas enters

[87] Or urea

the amine system. FGD technology utilizes limestone ($CaCO_3$) to convert SO_2 into gypsum ($CaSO_4 \cdot 2H_2O$), as represented in Equation 14.

Equation 14 $$CaCO_3 + SO_2 + \frac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O + CO_2$$

Both wet and dry FGD units are available; however, wet FGD systems dominate the market (Buvik *et al.*, 2021). In these systems, $CaCO_3$ is introduced into the top of a scrubbing column as an aqueous slurry, facilitating efficient SO_2 absorption and conversion. Wet FGD units remove over 90% of the SO_2 in flue gas (EPA, 2025a).

Cement plants typically do not employ dedicated wet FGD systems because the limestone contained in the raw meal provides inherent SO_2 capture. During the clinkerization process, the calcium carbonate in the meal acts as an in-situ dry sorbent, thereby reducing the need for external desulfurization units. Since almost complete elimination of SO_2 in the flue gas is often desirable to prevent solvent neutralisation and minimize amine reclamation requirements, a DCC or dedicated pre-scrubber[88] ahead of the amine absorber column is used as an SO_2 polishing unit. This is achieved by adding NaOH to the scrubbing solution, which enhances SO_2 removal according to Equation 15.

Equation 15 $$SO_2 + 2NaOH \rightarrow Na_2SO_3 + H_2O$$

An FGD system combined with a DCC using a basic polishing solution is commonly reported in the literature to achieve SO_2 concentrations below 5 ppm and achieve 99% SO_2 removal (Rochelle, 2024).

6.5.9 Specifications for Existing Co-Pollutants Concentrations

As previously discussed, aerosol formation, amine degradation, and NSA or nitramine (NA) formation are all issues that can result from co-pollutants in the gas stream. And, therefore, as discussed, equipment may be installed to decrease the concentrations of these co-pollutants.

Table 24 – MEA Criteria Co-Pollutant Concentration Requirements

Component	Kuramochi et al. 2012	Moser et al. 2025	Cement BAT-AEL (this report Table 5)	FCC BAT-AEL (this report Table 17)	Unit
PM	15	<2	<10-20	10-50	mg/Nm^3
NO_X	267 [a]	100-180	<200-800	<30 – 400	mg/Nm^3
NO_2	20	1-4	<15-60 [a]	<2-30 [a]	mg/Nm^3
SO_2	29	<1	<50-400	<100 – 1200	mg/Nm^3

[a] Calculated by the authors at 95 %vol NO to 5 %vol NO_2.

Table 24 presents a dated example concentration requirements for criteria co-pollutants (Kuramochi et al. 2012), along with an analysis at the absorber inlet of a recent real-world pilot plant, Niederaussem, capturing CO_2 from coal-fired power plant flue gas (Moser et al. 2025). The specification from Kuramochi et al. was employed in MEA modelling efforts for both cement and FCC applications. This specification

[88] Described in Section 6.1.5

generally aligns with the BAT-AEL requirements for cement and FCC processes, except for SO_2, which is specified at a significantly lower level.

In contrast, the flue gas at the Niederaussem pilot plant over complies the recommended limits for several co-pollutants, with the exception of NO_X. Niederaussem is equipped with a multistage ESP and wet slurry FGD unit. Although it lacks an SCR or and SNCR, it still meets BAT requirements through the use of staged combustion. At Niederaussem, SO_2 levels are reduced to very low concentrations through the addition of NaOH in the DCC. Compared to other pilot plants, Niederaussem has generally exhibited lower emissions and reduced solvent degradation (Moser *et al.*, 2020).

It is important to note that solvent technology providers are actively working to reduce the cost of CCS. As a result, they are developing solvents and mitigation methods capable of tolerating higher concentrations of criteria co-pollutants. However, the specific co-pollutant tolerance requirements for these solvents are proprietary and are not shared with the academic community when requested.

6.6 Degradation Product Air Emissions, Impacts, and Controls

Degradation caused by NO_2, as discussed in Section 6.5.6, along with other degradation pathways outlined in Section 6.1.3, leads to the formation and emission of degradation products. This section reviews these products and explores the corresponding control measures.

6.6.1 Degradation Product Direct Emissions Concentrations

For certain larger amines, there is a risk of degradation into smaller, volatile primary amines, such as methylamine (Buvik et al., 2024). It is advisable to avoid selecting secondary and tertiary amines prone to such degradation pathways (Rochelle, 2024). These smaller amines will eventually saturate the water wash and will be difficult to control. Notably, the amines used in CESAR1 exhibit a low risk of forming methylamine. Degradation of AMP would necessitate the cleavage of three carbon-carbon bonds, while PZ would require the breaking of at least two carbon-carbon bonds.

As the emission of smaller volatile primary amines are avoided by solvent properties, the common volatile degradation products for all amines are carbonyl species and ammonia (Vevelstad et al., 2022). During CHP testing of CESAR1 at TCM, degradation product emissions exceeding 50 ppb with CHP flue gas primarily consisted of small carbonyl species, including formaldehyde, acetaldehyde, and acetone (Languille *et al.*, 2021). 1-Nitrosopiperazine was detected at concentrations below 1 ppb in this study. Acetonitrile was also identified.

The Electric Power Research Institute's (EPRI) independent testing protocol for baseline testing solvents includes emission measurements from the following species

measurements of solvent, ammonia, formaldehyde, acetaldehyde, and acetone (Hume et al., 2022).

Table 25 – Air Emission Concentrations from FCC Flue Gas After the Amine Unit at TCM (S. Hume *et al.*, 2021; Hume *et al.*, 2022)

Component	Emission Concentration		Units
Solvent	CESAR 1	MEA 30%wt	
Primary Amine [a]	0.426-0.875	6.63-8.15	mg/Nm^3
Secondary Amine [a]	0.33-0.53		mg/Nm^3
NH_3	3.1-3.55	5.25-5.91	mg/Nm^3
Formaldehyde	0.32-0.38	0.05-0.08	mg/Nm^3
Acetaldehyde	0.18-0.27	5.70-6.55	mg/Nm^3
Acetone	1.91-2.59	<1	mg/Nm^3

[a] Amine degradation products such as other amines were not reported.

Table 25, a subset of Table 23, represents the air emission concentrations from TCM for FCC flue gas at the outlet of the pilot plant (with two water washes, the BDU, and a dry bed (trickle bed) installed for both MEA and CESAR1. Similar to the CHP testing at TCM, formaldehyde, acetaldehyde, and acetone are all quantifiable emissions for CESAR1 with FCC flue gas. Among these, acetaldehyde is the only significant emission observed when using MEA. Regarding NH_3, emissions are higher when using MEA compared to CESAR1 aligning with known increased rates of degradation[89].

Other degradation product categories that receive significant amounts of attention from researchers and regulators are nitrosamines (NSAs) and nitramines (NAs), as they have been proven to be or may potentially be carcinogenic and/or mutagenic at relatively low concentrations.

Secondary amines form stable NSAs in aqueous amine solvent systems, such as PZ (SEPA, 2015; Vevelstad *et al.*, 2022; Gibbins, Lucquiaud and Samson, 2024; Rochelle, 2024). However, the N-Nitrosopiperazine will also thermally degrade at desorber/stripper temperatures. (Fine, 2015). Therefore, it does not appear to accumulate in the solvent at meaningful quantities. For this reason, the formation of the N-Nitrosopiperazine in plumes[90] after amine emission is often of greater concern than accumulation within the solvent loop.

Although primary and tertiary amine systems do not form NSAs as readily in aqueous solutions, they can still be subject to NSA formation. If primary or tertiary amines produce secondary amine degradation products, these secondary amine by-products may form stable NSAs. For example, at TCM, baseline performance testing of MEA showed the formation of N-nitroso-2-hydroxyethyl-glycine N (Nitroso-HeGly) in the solvent (Morken *et al.*, 2014). HeGly is a secondary amine and known degradation production of MEA (Da Silva *et al.*, 2012). Furthermore, N-Nitrosodiethanolamine (NDELA) was found to accumulate in MEA solvents (Moser, Wiechers, Schmidt, Stahl, *et*

[89] See Section 6.1.3
[90] See Section 6.6.4

al., 2024a). Again, diethanolamine (DEA) is a secondary amine that degrades from MEA which will then form NDELA.

If a particular amine has impressive performance characteristics such as a high CO_2 loading capacity or lower regeneration heat requirements, but it more readily forms nitrosamines than other amines, technology providers must balance the enhanced risk of NSA formation against the benefit of reduced energy consumption.

Total NSA emission concentrations reported at the pilot plant vent stacks are presented in Table 23.[91] In nearly all cases, the detected levels are at or near the detection limit of the measurement device.

Nitrous oxide (N_2O) is a less considered compound because it is not classified within the NO_x family. However, it has a significant global warming potential and contributes to stratospheric ozone depletion (US EPA, 2016b; *Rise in nitrous oxide emissions endangers pathway to 1.5°C, the ozone layer, and human health*, 2024). N_2O can be formed through the decomposition of certain nitrosamines[92] (Fine, Nielsen and Rochelle, 2014).

6.6.2 Health and Environmental Impacts of Ammonia

Ammonia plays a critical role in the formation of $PM_{2.5}$, as described in Sections 6.1.1 and 6.3.2. Consequently, it poses similar health concerns to SO_X, NO_X, and amines due to its contribution to fine particulate pollution and associated respiratory and cardiovascular effects.

Beyond its role in $PM_{2.5}$ formation, NH_3 also contributes to environmental nitrogen deposition, leading to soil and water eutrophication. Excess atmospheric ammonia can be deposited onto terrestrial and aquatic ecosystems, where it undergoes nitrification and leads to soil acidification, altered nutrient cycling, and biodiversity loss (Erisman *et al.*, 2008; Sutton *et al.*, 2011). Increased nitrogen deposition is particularly problematic in sensitive ecosystems, such as wetlands and forests, where elevated nitrogen levels can disrupt plant communities and aquatic life (Galloway *et al.*, 2003). Additionally, ammonia emissions contribute to the formation of ammonium (NH_4^+) aerosols, which further exacerbate air pollution and visibility degradation (Seinfeld and Pandis, 2016). Given these impacts, effective ammonia emission controls are necessary to mitigate both air quality and ecological consequences.

6.6.3 Health and Environmental Impacts of Carbonyl Species

The OSHA permissible exposure limits (PELs) for formaldehyde and acetaldehyde are 0.75 ppm and 100 ppm, respectively. The carcinogenic reference level for chronic inhalation exposure to formaldehyde is 0.009 mg/m³ (Drewry *et al.*, 2025). As shown in Table 23, acetaldehyde and formaldehyde concentrations rarely exceed 100 ppb. After

[91] Regulatory limits are provided in Section 6.6.3.
[92] Discussed in Section 6.6.1.

accounting for dispersion from a well-designed stack, it is reasonable to expect that ground-level concentrations would remain below 0.009 mg/m³, suggesting that potential health impacts may be limited.

However, Rochelle noted that emissions of carbonyl species, many of which are considered EPA Hazardous Air Pollutants (HAPs) could trigger Title V permitting requirements, which involve an extended and more complex regulatory process (Rochelle, 2024). Subsequent work by Drewry et al. estimated that total HAP emissions from a 460 MWe amine-based CO_2 capture plant using 5 molar PZ with NGCC flue gas would range from 1.18 to 7.66 tons per year, depending on the emission control strategies implemented (Drewry *et al.*, 2025). At these levels, the Title V permitting would not be triggered. Other regulatory agencies may have different limits and frameworks for carbonyl species emissions.

6.6.4 Indirect Nitrosamine and Nitramine Emissions

NSAs and NAs do not only form in the amine unit itself. They also form in the plume due to reactions between amines and radicals, NO, and NO_2. Some regulatory bodies require operators to include an analysis of these reactions and the results on downwind receptors in their permit applications for CCS plants. Permit approval is typically contingent upon robust modelling demonstrating that predicted ground-level concentrations of these compounds remain below regulatory thresholds.

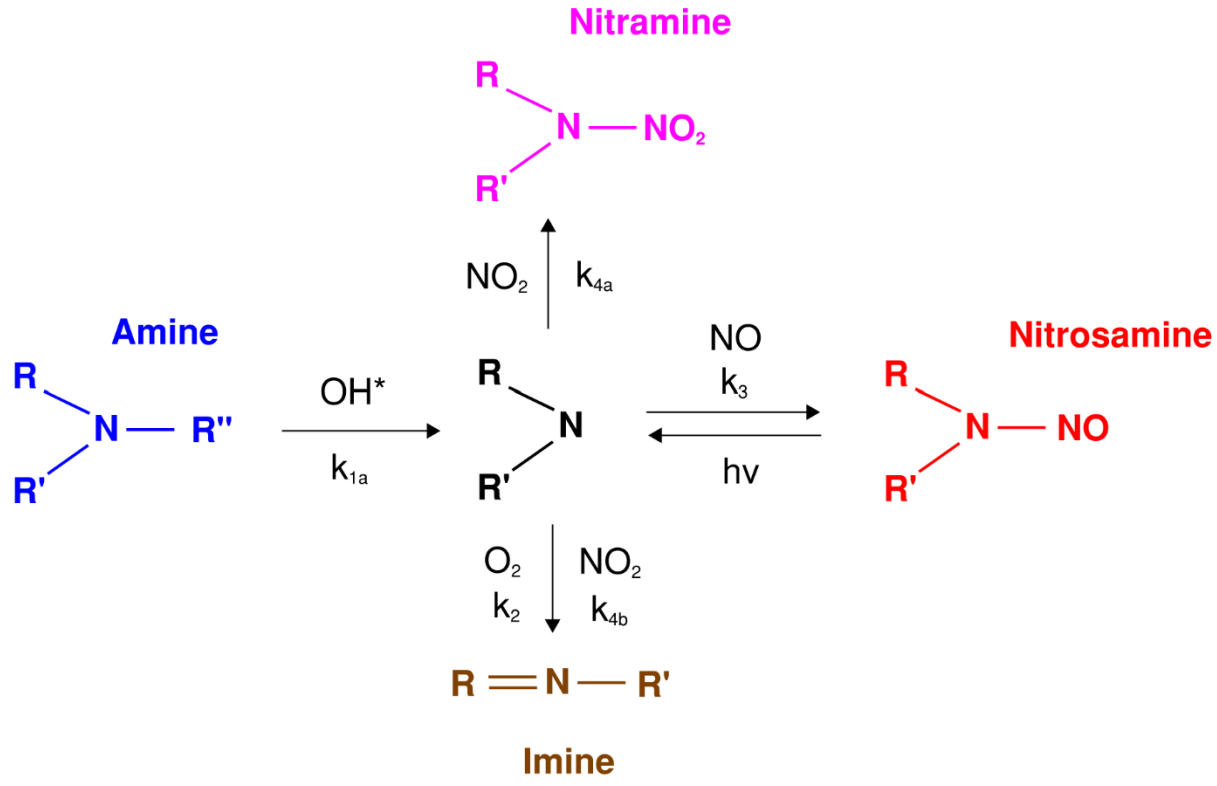

Figure 19 – The amine chemistry used in CERC's ADMS model for analysing NSA and NA formation in plumes, adapted from (Environment Agency, 2021)

Figure 19 illustrates the plume-phase amine chemistry first proposed by Nielsen et al. (Nielsen, Herrmann and Weller, 2012). In the figure, the hydroxyl (OH) radical is shown as the initiator of the reaction. However, it should be noted that under nighttime conditions, the nitrate (NO_3) radical becomes the dominant oxidant, significantly influencing nitramine formation pathways.

The kinetic rate constants ("k" values) for the reactions are derived from experimental laboratory data. This chemistry is utilized in Cambridge Environmental Research Consultants' (CERC) ADMS model. Modelling work using the chemistry outlined above has shown conversions of amine to nitrosamines in ambient air can reach as high as 8% (SEPA, 2015).

It is important to note that this chemistry differs significantly from the stable nitrosamine formation chemistry within the amine unit's solvent, where dissolved NO_2 forms nitrite, which subsequently reacts with secondary amines to produce nitrosamines, as shown in Equation 11 and Equation 12.

NO is a key precursor to NSA formation in the plume. However, it is not believed to be a significant precursor to NSA formation within the amine unit itself (Chen and Rochelle, 2022). Consequently, technologies that remove all NO_X (e.g. SCR and SNCR), as discussed in Section 6.5.7, can significantly decrease NSA formation in the plume. Removing only NO_2 immediately upstream of the amine plant while leaving the NO will only reduce NSA formation within the amine plant itself.

When modelling NSA formation in the plume, it is important to account for both solvent emissions and solvent degradation products that are amines. Degradation products such as dimethylamine (DMA), which can form N-nitrosodimethylamine (NDMA), are of particular interest[93]. DMA is commonly detected as a degradation product emission from PCC plants using amine solvents (Morken *et al.*, 2014; Neerup *et al.*, 2023).[94] Therefore, for plume modelling to be effective, emissions of these species at the stack must also be quantified via the methods outlined in Section 6.1.4.

Another important consideration when modeling NSA and NA formation in plumes is the interaction with emissions from nearby stacks. This is particularly relevant in industrial clusters, where multiple emission sources may influence plume chemistry. NO_2 emissions from secondary stacks can react with amine emissions from the primary stack. Additionally, other stacks equipped with amine-based carbon capture systems may contribute to cumulative NSA and NA formation, potentially compounding impacts at downwind receptors.

[93] Subsequently discussed in Section 6.6.5[94] NDMA was measured at or below the detection limit at the absorber outlet in these studies.

[94] NDMA was measured at or below the detection limit at the absorber outlet in these studies.

When plumes are modeled using the chemical mechanisms outlined in Figure 19, a significant portion of the expected NSA formation at downwind receptors is anticipated to result from indirect rather than direct emissions. For instance, a recent permit application in the UK for a MEA solvent project at the Teesside NGCC plant indicated that maximum exposure to (NDMA) would be attributed 43% to direct emissions and 57% to NDMA formation within the plume (Environment Agency, 2024b). However, this approximate distribution represents a single case and should not be assumed applicable to other scenarios. The results are highly dependent on the amine considered, modelling approach, background pollutant levels, and atmospheric conditions, and weather conditions including temperature variations. In this particular case, it is suspected that indirect emissions are less prevalent because the majority of the amine emissions consist of MEA. As a primary amine, MEA does not readily convert to NSAs unless it first undergoes transformation into a secondary amine.

A recent study of air quality impacts from the planned conversion of two units at Drax to BECCS operation using an MHI solvent, undertaken by WSP, found that direct emissions accounted for only a minor proportion of the total impact (WSP, 2024). The modelling was carried out using ADMS. A conservative assumption was adopted, namely that no degradation of nitrosamines or nitramines would occur once emitted to the atmosphere. Even under this assumption, predicted concentrations of nitrosamines due to direct emissions at downstream receptors were on the order of 0.1% of the Environmental Assessment Level (EAL). By comparison, the total predicted concentrations of nitrosamines and nitramines (including atmospheric formation products) were 12.5% and 13.0% of their respective EALs, respectively.

Other researchers are developing new modelling approaches. For example, EPRI has developed the Second-Order Closure Integrated Puff Model with Chemistry (SCICHEM) to simulate NSA and NA in plumes (Knipping *et al.*, 2025). Unlike traditional Gaussian plume models such as ADMS, which assume continuous dispersion, SCICHEM represents the atmosphere as a series of discrete puffs or parcels of air that evolve over space and time. However, EPRI's model is currently limited to only 3 amines[95].

Ideally, modelling efforts should be confirmed by analysis of atmospheric levels of NSA and NA at receptors. In 2015, SEPA's literature review concluded that no reliable method for measuring nitrosamine levels in ambient air at ng/Nm^3 levels[96] (SEPA, 2015). This literature review did not uncover a revision to this finding.

[95] MEA, AMP, and PZ

[96] Submicron exposure limits are required by regulators. Limits are discussed in the subsequent Section 6.6.5.

6.6.5 Health and Environmental Impacts of Nitrosamine and Nitramines

A recent literature review conducted by Imperial College London as part of the SCOPE project highlighted the following key points regarding the human health hazards of NSA and NA (Lathorui et al., 2022):

- NSA are approximately 15 times more potent carcinogens than NA.
- Based on available research, NDMA and N-nitrosomorpholine (NMOR) pose the greatest carcinogenic health risk.[97]
- Few toxicity studies exist for NA. However, from the available literature, similar to NSA, the NA derivative of DMA appears to have the highest toxicity.
- The Norwegian Institute of Public Health (NIPH) has set a guideline for total NSA and NA at 4 ng/L in water and 0.3 ng/m³ in air.

The authors of the SCOPE literature review, along with other researchers, have suggested that these NIPH limits are likely conservative, as they were set based on calculations derived from the toxicity of NDMA, the most potent known NSA (Rochelle, 2024). The UK Environment Agency (EA) has established a more conservative limit than the NIPH for NDMA exposure in air at 0.2 ng/m³. Additionally, the UK EA requires permit applicants to derive specific limits for other NSA and NA. Due to the lack of comprehensive toxicity data on many of these compounds, some permit applicants have adopted the approach of combined all NSAs and NA emissions into a single "as NDMA" category and use the established NDMA EAL, which has been deemed acceptable by UK regulators (Environment Agency, 2024b).

In addition to the Imperial College London literature review, a parallel review conducted by SINTEF Ocean as part of the SCOPE project also identified low temperatures, shorter daylight periods, pH, concentration, and dissolved organic carbon as key factors influencing the decay of NSA and NA (Lathorui *et al.*, 2022; Brakstad *et al.*, 2023).

Although NA are less potent carcinogens than NSA, they are more resistant to photodegradation (Brakstad et al., 2023). This has led to debate regarding whether their environmental persistence makes them potentially more concerning than NSA. A parallel literature review, conducted by SINTEF Ocean, as a part of the SCOPE project reached the following conclusion:

> *Although nitramines exhibit resistance towards photodegradation, they are formed in sufficiently low quantities and disperse quickly enough that they will most likely reach environmental concentrations significantly below limits and*

[97] Although, not explicitly noted in the Imperial College report, N-Nitrosodiethylamine (NDEA) has also been shown to be only slightly less carcinogenic than NDMA (SEPA, 2015). And, the Carinogenic Potency Database states that NDEA is in fact more carcinogenic than NDMA or NMOR (Svendsen *et al.*, 2024).

they will be less of a concern from a toxicological perspective. (Brakstad et al., 2023)

Another key finding from the SINTEF Ocean literature review is that both NSA and NA are potentially persistent in the environment, particularly when transported to low-light environmental compartments such as groundwater. While regulatory efforts have focused on setting exposure limits to mitigate public health risks, it remains uncertain whether these limits are adequate to prevent long-term environmental persistence. Regulators are calling for additional research into this area of study (McIntyre and Barraclough, 2025).

The FuNitr project aims to address this knowledge gap (*Future Drinking Water Levels of Nitrosamines and Nitramines near a CO2 Capture Plant (FuNitr)*, 2023). As part of this initiative, additional experiments will be conducted to assess the biodegradability of NA. Furthermore, an atmospheric-catchment simulation will be developed to analyze the accumulation of NSA and NA over a 20-year period in bodies of water.

6.6.6 Control of Degradation (Solvent Management)

Degradation can be controlled by eliminating substances in the amine solvent that contribute to degradation. Upstream controls to limit NO, which leads to NSA formation in the plume, and NO_2, which contributes to both degradation and NSA formation within the amine unit, were discussed in Section 6.5.7.

As shown in Equation 5, dissolved O_2 promotes degradation. Oxygen can be removed from the solvent through N_2 sparging of the absorber sump or by using a dissolved oxygen removal apparatus (DORA) (Chen and Rochelle, 2022; Vevelstad *et al.*, 2022; Braakhuis and Knuutila, 2023).

Dissolved metals can also catalyze degradation reactions (Chen and Rochelle, 2022). Therefore, solvent reclaiming, as discussed in Section 6.4.3 , can be used to remove dissolved metals that facilitate degradation. Additional methods for removing dissolved metals include bleed-and-feed processes and particulate filtration (Vevelstad *et al.*, 2022).

The “bleed and feed” approach, consists of a significant portion of the solvent inventory being removed and replaced with fresh solvent. However, findings from the ALIGN-CCUS project indicated that this method would only yield a meaningful impact, for solvents which behave like MEA, if the entire solvent inventory were replaced (Moser *et al.*, 2020). Given the associated cost, such an approach is not considered justifiable when other reclaiming options are available.

A recent studies at Niederaussem, a coal-fired power plant using highly aged CESAR1 solvent, have shown that removing anionic degradation products, including metals and metal complexes, via ion exchange increased the formation of oxidative degradation products by a factor of three (Moser, Wiechers, Schmidt, Stahl, *et al.*, 2024b). In other

words, reclaiming accelerated degradation. Proposed reasons for this are provided in Moser et al.'s 2024 paper. Furthermore, certain degradation products have also been found to tune down the redox behavior of metal cations and reduce amine degradation in MEA (Buvik *et al.*, 2023). These counterintuitive finding challenges traditional assumptions about the universal benefits of reclaiming and underscores the importance of solvent-specific management strategies.

This perspective is echoed by guidance from an expert at the National Carbon Capture Center (NCCC), who stated:

> *Reclaiming is a solvent-specific issue. The goal is to identify the level of reclaiming that maintains consistent solvent performance across the entire solvent volume while avoiding unnecessary energy consumption and accelerated degradation resulting from high-temperature reclaiming.* (Carroll and Esposito, 2025)

Taken together, these insights suggest that reclaiming should not be applied indiscriminately or on a fixed schedule, but rather optimized based on solvent condition, degradation pathways, and operational objectives.

6.6.7 Downstream Degradation Product Control

Downstream technologies thus far discussed have not been proven effective in reducing aldehyde and NH_3 emissions (Drewry *et al.*, 2025). Both aldehydes and NH_3 have relatively high Henry's constants, making capture with water washes ineffective.

A more effective method for removing NH_3 is the use of an acid wash. As a basic compound, NH_3 readily reacts with an acid wash to form a salt. Acid washes also provide the additional benefit of reducing alkyl amine emissions, as amines are also basic compounds that react with acid. However, a key drawback of acid washes is the generation of a salt waste stream contaminated with amines, including the potential presence of NSAs.

Table 23 presents several studies demonstrating that acid wash implementation significantly reduces NH_3 emissions. In general, NH_3 emissions can be controlled to below 5 ppm with a well-designed acid wash. However, acid washes have no significant impact on reducing aldehyde emissions (Drewry *et al.*, 2025). No effective method for controlling aldehyde emissions has been identified beyond relying on atmospheric dispersion.

Acid washes for post-amine unit emissions represent a relatively new technology, and optimal operating parameters have not yet been comprehensively outlined in the literature. Additionally, operators remain cautious about managing the additional waste stream. However, the effectiveness of acid washes is well established, and industry experts are increasingly advocating for their inclusion in emission control strategies (Carroll, 2025). Recent permit applications in the UK indicate that operators are either

including or incorporating provisions for acid washes in their designs (Environment Agency, 2024b, 2024b). Acid washes are always installed downstream of water washes to ensure they do not interfere with the water recovery objectives of the water wash system.

SEPA concluded that most nitrosamines are water soluble (SEPA, 2015). And, NSA and NAs have similar Henry's constants and basicity to their parent amine (Drewry *et al.*, 2025). Consequently, for NSA and NA formed within the amine unit, water washes, as described in Section 6.3.2, are effective in mitigating their emissions as long as their parent amines are effectively mitigated by water washes. In fact, some nitrosamines, such as PZNO, are less volatile than their parent amine and are more likely to be absorbed by the water washes (Rochelle, 2024).

It is noteworthy that no significant reduction in NSA emissions was observed following the installation of the BDU at the Maasvlakte pilot plant using an MEA solvent system (Khakharia, Kvamsdal, *et al.*, 2014). This suggests that NSA emissions are more prevalent in the vapor phase rather than the mist phase.

Recent unpublished results from the SCOPE project have found that dry bed (trickle bed) technologies when using the CESAR-1 solvent system can play a significant role in reducing NSA emissions. Operators of the dry beds (trickle beds) believe it is effective at removing both aerosol-based and volatile emissions and will reduce NSAs to one-digit ppb levels.

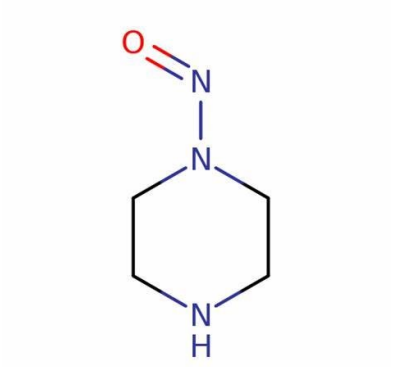

Figure 20 - The Chemical Structure of N-Nitrosopiperazine

In the CESAR1 system, it's worth noting that most prevalent NSA, N-Nitrosopiperazine, has a second amino group that is not changed when the NSA is formed from piperazine, see Figure 20. This amino group makes the compound basic. And, therefore, acid washes are expected to be effective at capturing this NSA (Rochelle, 2025).

Minimizing NSA and NA formation in the plume can be achieved by limiting both amine and NO_X emissions. Water washes have been discussed as a method to reduce amine emissions, while strategies for controlling NO_X emissions are detailed in Section 6.3.2 and Section 6.5.7, respectively.

Finally, one of the most effective methods for ensuring that ground-level concentrations of emissions do not pose a hazard to human health, or the environment is the use of a well-designed stack.

6.7 Indirect Co-Pollutant Emissions from Amine Units

The deployment of CCS requires additional thermal and electrical energy, and the generation of this energy can lead to increased emissions. Rochelle argued that, in the case of power generation, facilities may repurpose existing energy capacity rather than construct new energy infrastructure. This approach would involve reducing exported power rather than increasing overall fuel consumption. Given the ongoing transition of the electricity grid toward renewable energy sources, such adjustments would likely result in no net increase in co-pollutant emissions (Rochelle, 2024). However, this is very dependent if renewable generation is the predominant source of new generation. Others have shown that if new power demand is fulfilled with CCS fossil projects (incentivized by tax credits) rather than renewable projects, air pollution and carbon emission impacts will not be net zero and the relative impacts are worse in the CSS fossil case (Jacobson, 2019; Grubert and Sawyer, 2023).

However, this option is not available to heavy industrial applications such as cement production, where there is insufficient waste heat available to operate a post amine CCS plant. In these cases, the additional heat required for CCS would likely be generated by a new natural gas-fired boiler, combined with grid-supplied electricity, or by installing a dedicated CHP plant. While natural gas combustion produces lower emissions compared to other fossil fuels, the primary environmental concern remains the generation of additional NO_X emissions, which can be partially mitigated using SCR technology.

Nevertheless, depending on the location and the specific design of the amine-based CCS system, certain heavy industry CCS projects may result in a net increase in NO_X emissions. For example, in 2022, the Heidelberg Materials Brevik plant emitted approximately 82 tonnes of CO_2 per hour. A PCC amine-solvent CCS system designed to capture 90% of this CO_2 would require approximately a 75 MWth[98] natural gas-fired boiler and an additional 16 MWe[99] of grid electricity . If a 75 MW boiler targeting 35 mg/Nm^3 NO_X[100] were installed to meet this demand, it would result in an additional 80 metric tons of NO_X emissions per year[101]. This is on top of the 555 metric tons of NO_X the plant currently emits each year.

[98] 3.23 GJ/tCO_2 (Hume *et al.*, 2022)

[99] 0.20 kWh/kgCO_2 (Arias *et al.*, 2016). Includes compression and pump work for transport and sequestration.

[100] Average value of the new plant BAT-AEL for boilers in the EU Large Combustion Plant BREF (European Commission. Joint Research Centre., 2017).

[101] 3,500 Nm3 of flue gas / MWth at 8,760 hr/year.

The NO_X emissions from grid electricity depend on the regional grid intensity, which can range from 0 to 4 g NO_X/kWh[102], depending on the proportion of natural gas and renewable power in the energy mix. At the upper bound (4 g NO_X/kWh), an additional 16 MWe of grid power would contribute up to 569 metric tons of NO_X annually, while at the lower bound (0 g NO_X/kWh, fully renewable grid), there would be no additional NO_X from grid electricity. Even under the best-case scenario, where grid emissions are negligible[103] and 5% of Brevik's 2023 NO_X emissions (28 tons) are offset by using thiosulfate to remove NO_2 ahead of the amine plant, the facility would still emit more NO_X emissions due to the deployment of a PCC amine plant.

A similar conclusion was reached in a 2012 IEAGHG report (IEAGHG, 2012). However, it is important to recognize that a marginal increase in NO_X emissions does not necessarily correspond to a significant increase in environmental or health impacts. Regulatory agencies require that any additional NO_X emissions be properly dispersed to decrease adverse impacts on local air quality or surrounding communities.

The 35 mg/Nm³ value and grid-connection assumption discussed above do not reflect the alternative option of using a newly constructed natural gas CHP plant equipped with an SCR system capable of achieving 4 mg/Nm³ (approximately 2 ppmv). In this particular scenario, the total NOx emissions from this CHP plant are approximately 9 tons/year.[104] Accordingly, the use of thiosulfate to remove NO_2 ahead of the amine plant can indeed reduce overall NOx emissions by offsetting this addition.

Moreover, strategies such as employing heat pumps or electric steam generators to supply the reboiler duty may be adopted to ensure that net NOx emissions do not increase when amine-based PCC projects are deployed. Overall, these considerations highlight the substantial influence that the choice of energy source exerts on co-pollutant emissions in amine-based capture plants, as well as the significant capital implications this choice carries for plant deployment.

6.8 Liquid Waste Streams from Amine Units

In addition to gaseous co-pollutants, the impacts of liquid pollutants should also be considered. There are generally four liquid waste streams: (1) bleed streams from upstream pre-scubbers, DCCs, and/or continuously washed BDUs, (2) reclaiming waste, (3) acid wash waste, and (4) CO_2 compression and dehydration systems.

The bleed stream from inlet scrubbing typically consists of a slightly basic aqueous solution containing sulfate salts (from SO_2 removal), chloride salts (from HCl removal), and potentially nitrate salts (if NO_2 is removed using thiosulfate). It may also contain particulate matter, with the concentration dependent on the effectiveness of upstream

[102] Highest grid NO_X intensity in the US (US EPA, 2020).
[103] A good assumption for Norway's grid which primarily uses renewable power.
[104] 65% net efficient CHP exporting 78 MWe of excess electricity offsite.

control technologies such as ESPs, baghouse filters, or BDUs. Additionally, in systems equipped with SCR or SNCR units, trace ammonia may be present due to ammonia slip.

No studies were identified in the literature that specifically address the disposal of this particular waste stream. However, its basic nature allows for neutralization using acid, and the concentrations of dissolved salts are generally expected to be low enough to present minimal environmental risk. Conventional, cost-effective wastewater treatment methods, such as biological treatment (for ammonia) and chemical precipitation (for heavy metals or particulates), are likely to be sufficient for managing these streams.

Industrial facilities such as iron and steel plants and refineries typically possess appropriate wastewater treatment infrastructure to accommodate this type of discharge. In contrast, cement plants, which often lack wet flue gas scrubbing systems, may require upgrades to existing treatment infrastructure or rely on nearby municipal wastewater treatment facilities equipped to manage such streams.

The second stream is reclaimer waste, as described in Section 6.4.3. Thermal reclaiming likely produces the most challenging waste stream, as it contains both ionic and non-ionic degradation products. In contrast, ion-exchange and electrodialysis reclaimer waste contain primarily ionic species.

Batch thermal reclaimer waste typically contains salts (including sodium nitrate, and salts of methanoic, ethanoic, and ethandioic acids), thiosulfates, thiocyanates, sodium sulfate, trace metals (such as chromium, copper, iron, nickel, and selenium), oxidized mercury, amine compounds, and corrosion inhibitors (SEPA, 2015). The most straightforward disposal method for this stream is incineration, although aerobic digestion may offer a less expensive alternative (Nurrokhmah, Mezher and Abu-Zahra, 2013). Ideally, opportunities for beneficial reuse or upgrading of this stream should also be explored.

A recent review of alternatives to incineration by Ghayur, Verheyen, and Meuleman concluded that biological treatment of amines is the most mature alternative technology and highlighted the potential for amines to serve as feedstocks for value-added products (Ghayur, Verheyen and Meuleman, 2019). However, a 2014 report by IEAGHG cautioned that nitrate concentrations in reclaimer waste may be too high to allow for effective biological treatment (IEAGHG, 2014). Additionally, the high nitrogen-to-carbon ratio in this waste may result in excess ammonia formation, which can cause pH inhibition in biological systems (SEPA, 2015). This excess ammonia also poses a risk of toxicity to aquatic organisms if not properly managed.

Another promising option identified by Ghayur, Verheyen and Meuleman is the use of waste amines as a substitute feedstock for $DeNO_X$ equipment, such as SCRs and SNCRs, in place of conventional ammonia. Ghayur, Verheyen and Meuleman recommended further research into these approaches, with particular emphasis on evaluating the impact of non-amine impurities present in the waste stream. However,

depending on the regional specific regulatory framework this approach might not be possible.

No literature was identified that quantitatively reports NSA or NA in reclaimer waste. However, their presence may be significant. Studies that have measured total nitrosamines (TONO) in amine solvents before and after reclaiming report substantial reductions, suggesting that these compounds are removed or degraded during the reclaiming process.

Studies examining the removal of nitrosamines in municipal sewage treatment systems have reported activated sludge removal efficiencies ranging from 43% to 89%, depending on the compound (Krauss *et al.*, 2009). However, these removal efficiencies are unlikely to be sufficient for treating reclaimer waste streams with nitrosamine concentrations on the order of milligrams per liter. Therefore, based on the preliminary calculation above, conventional wastewater treatment is unlikely to be sufficient for handling such waste streams. Although the disposal method is not explicitly stated in the Gorset et al. study, the high concentration of NSAs strongly suggests that incineration was the most likely method used. However, a detailed chemical characterization of reclaimer waste from specific facilities is necessary to confirm this assessment and to support the selection of appropriate treatment methods.

If incineration is selected as the disposal method for this stream, co-pollutants originally captured by the amine plant, through the formation of HSS and solvent degradation, may be re-emitted to the atmosphere unless appropriate preconditioning steps and air quality control measures are implemented. For example, the NO_2 absorbed to form NSAs could be oxidized back to NO_X.

Alternative treatment technologies, such as reverse osmosis, ultraviolet (UV) irradiation, ozonation, and advanced oxidation processes (e.g., ozone combined with hydrogen peroxide), have been proposed for the effective treatment of nitrosamines in aqueous streams (SEPA, 2015). While these technologies show promise, no detailed studies were identified in this literature review regarding their application to the complex chemical composition of reclaimer waste streams.

No literature was identified that characterizes acid wash waste streams in detail. However, it is reasonable to expect that NSA and NA concentrations in these streams are significantly lower than those observed in reclaimer waste, though potentially still present at environmentally relevant levels. Acid washes may function analogously to the second bed in a two-stage water wash system, providing additional polishing contaminants.

Studies measuring TONO concentrations in second-stage water wash systems have reported values near analytical detection limits. For example, during baseline performance testing of MEA on CHP flue gas at TCM, the TONO concentration in the

second-stage wash water was reported at <0.05 µmol/L (Morken *et al.*, 2014), which corresponds to <6 µg/L if assumed to be Nitros-HEGly.

The relatively pure CO_2 stream leaving the amine plant is typically compressed for transport and sequestration. This compression process leads to the condensation of residual species[105], which must be appropriately managed. In addition, the CO_2 stream is commonly dehydrated using a triethylene glycol (TEG) unit. TEG is highly hygroscopic, absorbing water in an absorber column. The water-laden TEG is then sent to a regenerator, where heat is applied to boil off the absorbed water. This water is typically vented to the atmosphere.

Given the polar nature of amines, particularly those with hydroxyl groups, it is likely that trace amounts of amines are also absorbed by the TEG and subsequently released during regeneration. These emission points are often overlooked, and this literature review found no studies specifically addressing the composition or environmental fate of the condensate or TEG regenerator vent streams. Simple solutions such as routing these vent streams to the amine absorber, other process modifications, or a taller stack may address this concern.

Although the volume and contaminant concentrations in these CO_2-side waste streams are expected to be lower than those in the flue gas-side streams, they should not be assumed to pose negligible risk. For instance, the use of a short stack on the TEG regenerator vent could lead to localized ground-level impacts if amines or other volatile contaminants are present.

Some projects, such as Norway's Longship/Northern Lights CO_2 transport and storage project, prohibit the use of TEG dehydration due to concerns about its long-term impacts on reservoirs (Northern Lights, 2024). As a result, molecular sieve dehydration has been adopted as the preferred technology for these projects. It will also be important to confirm that amines are not adsorbed by molecular sieves at levels that could lead to similar concerns.

6.9 Solid Waste Streams from Amine Units

The only reference found to solid waste streams was a note in the 2015 SEPA review that stated activated carbon waste from filters could be generated between 0.03 and 3.2 kg/tCO_2 captured (SEPA, 2015).

6.10 Recommended Controls for an Amine Units in the Power Sector

Section 6.3 through 6.6 were written to provide information applicable to flue gases from any industry. The following two sections (6.10 and 6.11) reviews literature focused on specific industrial sectors. A substantial body of work has been dedicated to developing recommended practices for emissions control in amine-based CCS within

[105] Such as water, ammonia, and amines

the power sector. Consequently, this review begins with findings from this sector, which are likely applicable to heavy industry as well.

A comparison of MEA pilot plant studies on coal flue gases by Buvik et al. concluded that flue gas pretreatment for the removal of SO_X, NO_X, and PM significantly reduces solvent degradation. This review compared coal power plants equipped with BAT technologies (FGD, SCR, and ESPs) against those without such controls, finding a substantial increase in degradation product formation in facilities lacking these technologies (Buvik *et al.*, 2021). However, the study did not specify which control technology or pollutant was primarily responsible for the observed reduction in degradation products. Nonetheless, this work provides strong evidence that achieving BAT compliance effectively mitigates solvent degradation in MEA-based carbon capture systems.

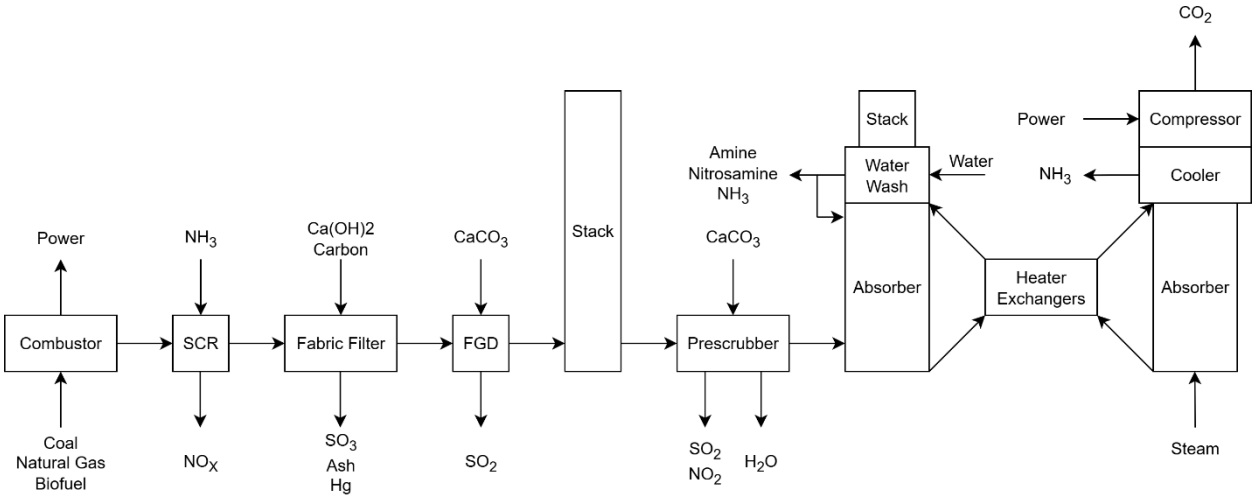

Figure 21 - Retrofit of amine scrubbing on an existing coal-fired power plant, adapted from (Rochelle, 2024)

Figure 21 illustrates several air quality control units recommended for installation upstream of the amine unit (Rochelle, 2024). Rochelle recommends the installation of an SCR unit to reduce NO_X levels to below 20 ppm, thereby minimizing amine oxidation and the formation of nitrosamines. For fine particulate and SO_3 removal, a baghouse filter unit with upstream injection of calcium hydroxide ($Ca(OH)_2$) and activated carbon is utilized. The $Ca(OH)_2$ injection neutralizes sulfuric acid, effectively removing SO_3. Baghouse filter units are common in the US. Whereas, electrostatic precipitators are common in Europe. Subsequently, a flue gas desulfurization (FGD) unit removes 90–98% of SO_2. Finally, a tall stack is recommended to ensure remaining pollutants are effectively dispersed.

In the U.S., these units are already considered Maximum Achievable Control Technologies (MACT), the American equivalent of BAT, for coal-fired power plants. However, depending on the age of a power plant, not all units may be installed.

Due to the impact of SO_2 on amines[106] a solution containing NaOH in the DCC is used to further remove any residual SO_2 not captured by the FGD unit by adding a base to the DCC wash water. The SO_2 concentration exiting the unit can be reduced to as low as 1 ppm.

Several alternatives to the DCC for flue gas cooling have been proposed, including (Gibbins, Lucquiaud and Samson, 2024):

- Water fogging in the flue gas transfer duct,
- A low-grade heat recovery exchanger, or
- A heat exchanger that reheats the flue gas exiting the top of the absorber to aid plume dispersion.

However, these methods do not effectively remove SO_2, and fogging could potentially generate aerosols. As a result, they are likely to be considered only in cases where additional SO_2 removal does not provide significant economic benefits.

Rochelle further recommends water washes and, potentially, an acid wash bed at the top of the absorber column in the amine absorber to capture amine, nitrosamines, and NH_3 before they are released into the atmosphere for the reasons discussed in Section 6.3.2, 6.6.2, and 6.6.5.

The recommendations outlined by Rochelle align closely with the directives of a recent UK Environment Agency (EA) guidance document. The UK EA, in collaboration with the UK CCS Research Centre, developed this guidance to address emerging techniques for mitigating the environmental impact of PCC in power and waste-to-energy (WtE) facilities (Environment Agency, 2024a; Gibbins, Lucquiaud and Samson, 2024). As always, such documents must be kept under review as new information is learned from pilot plants with real flue gas and under industrial boundary conditions.

The guidance highlights the choices available to operators regarding solvent selection. As discussed in Section 6.6.1, amines are less likely to form stable NSAs within the PCC plant, whereas secondary amines which can be also formed by primary amines due to degradation offer greater energy efficiency due to their lower regeneration heat requirements but may form stable NSAs.

Regardless of the solvent selected, the UK EA recommends the use of SCR to minimize NO_X concentration to the lowest possible level, presumably to reduce NSA and NA formation. However, an exception is made for WtE plants, which are permitted to use SNCR instead. The same conclusion was reached in a recent United States Energy Associations (USEA) workshop (USEA, 2023).

[106] Discussed in Section 6.4.3

The UK EA states that the decision to install an FGD unit for SO_X removal is primarily an economic consideration. Removing SO_X reduces the formation of HSS, thereby decreasing solvent consumption and lowering operating costs.

Additionally, the UK EA mandates that SO_3 and fine particulate matter be removed before the flue gas enters the amine capture unit to avoid mist-phase amine emissions. While the guidance does not prescribe a specific methodology for aerosol removal, it outlines several potential control strategies, including[107]:

- Cooling the flue gas to the acid dew point,
- Brownian demisters,
- Wet electrostatic precipitators (ESPs), and
- Operating with a high lean solvent temperature.

However, it is important to note that the fourth option can significantly reduce CO_2 loading in the amine solvent. As discussed in Section 6.1.5, lower temperatures improve CO_2 loading in the amine. Furthermore, at least in one case, operating with higher lean solvent temperature increased emissions[108]. High lean solvent temperature can increase volatile emissions whereas it can lower aerosol emissions.

The UK EA mandates the use of one or two water wash stages, depending on the volatility of the amine solvent, as well as an acid wash downstream of the absorber column. However, operators may forgo the acid wash if emissions are already below 0.5 to 5 mg/m^3 or if they can demonstrate that the environmental impact of acid wash waste disposal exceeds the impact of additional atmospheric emissions. This exemption highlights regulatory uncertainty regarding the environmental consequences of acid wash waste streams.

In addition to water and acid washes, the guidance requires the inclusion of a "droplet removal section," which is interpreted here as a demisting pad. However, the document explicitly acknowledges that such devices are ineffective at capturing SO_3 and other ultrafine aerosols.

Finally, the UK EA requires operators to model the dispersion of any remaining co-pollutants and, if necessary, mitigate their impact by increasing stack height or reheating the flue gas to ensure compliance with environmental quality standards.

The recommendations and directives outlined by Rochelle, Gibbins et al., and the UK EA, are in agreement with the conclusions of this literature review, with the exception of two key points:

[107] Dry beds (trickle beds) are not included in the list of potential control strategies. However, they are also a technology capable of reducing mist-phase amine emissions.
[108] See Section 6.5.3

1) **Caution is recommended when considering the use of a wet ESP for aerosol nuclei removal ahead of an amine plant.** In at least two cases, wet electrostatic precipitators (ESPs) have been observed to generate aerosols. At the Niederaussem pilot plant (coal-fired power plant flue gas), aerosols were generated when the wet ESP was used (Moser, Wiechers, Stahl, *et al.*, 2023). This may be a problem specific to flue gas streams with high sodium content. Additionally, an increase in SO_3 aerosols was observed at the lab scale when SO_2 was present in the flue gas feeding a wet ESP (Khakharia, Huizinga, et al., 2014). Both studies suggest that wet ESPs provide a liquid-phase medium for complex chemical reactions that can generate undesirable aerosols.
2) **Mandating SCR and SNCR installation may hinder CCS deployment and impose unnecessary capital costs on operators.** Regulators should balance the benefits from emission reduction with the costs of imposing a mandate if alternative technological approaches are available. For example, at Niederaussem, NO_X production is controlled to BAT levels via burner configuration. Further NO_X reductions using SCR or SNCR would potentially reduce NSA and NA plume formation, but these may not be necessary with certain solvent selections, appropriate emission mitigation measures, and stack height adjustments. While NSA and NA plume formation must be controlled, there is no reason to strictly dictate the method. Instead, flexibility could be granted for alternative mitigation strategies.
   However, an alternative argument for the deployment of SCRs is that they would improve overall air quality in industrial clusters. This may result in a reduction to local opposition of PCC projects.

6.11 The Impact of Amine Units on Co-Pollutants in Heavy Industry

A handful of studies in both academic and grey literature have attempted to quantify the impacts of amine solvent CCS deployment on co-pollutants in heavy industry.

The earliest known study was conducted by Kuramochi et al. in 2012 (Kuramochi *et al.*, 2012). This study attempted to quantify the total impact of deploying CO_2 capture technologies on co-pollutant emissions in the European cement, petroleum refining, and iron and steel industries. MEA-based post-combustion carbon capture was assumed for the cement and refining sectors, while blast furnace top gas recycling (TGR) with vacuum-pressure swing adsorption (VPSA) was considered for carbon capture in the iron and steel sector. The findings indicated that relative to total EU industrial emissions at the time, SO_2 emissions would decrease by 40–70%, NH_3 emissions would increase by 120–520%, NOx emissions would change between a 10% decrease and 10% increase, and PM emissions would slightly decrease up to 10%.

The study employed a rigorous and well-reasoned methodology. However, one key limitation is that the projected NH_3 emissions are potentially overestimated due to the assumption that amine-based capture units would operate without a water or acid

wash and MEA was used at 85% CO_2 removal efficiency instead of a G2 solvent at 95% CO_2 removal efficiency.[109] Additionally, the majority of the SO_2 reduction observed in the study was attributed to the assumption that new combined heat and power (CHP) plants would be constructed to supply steam to the amine unit. The study granted co-pollutant reduction credit to these CHP plants for exporting electricity, thereby offsetting emissions from a high-emissions power grid.

Despite these methodological shortcomings and the age of the study, some of the study's core qualitative conclusions, including that SO_2 emissions would decrease, solvent degradation products would increase, NO_X emissions would remain relatively unaffected, and PM emissions would decrease, generally align with the authors' understanding of the impacts of amine-based CCS deployment, which will be discussed in Section 9.1.

Following this study, limited research was conducted in this area until three recent attempts in grey literature sought to assess the impact of amine solvent-based CCS technology on heavy industry flue gas. The first of these was prepared by the Great Plains Institute in 2023 (Bennett *et al.*, 2023). This study postulated that emissions of NO_X, SO_2, and $PM_{2.5}$ would decrease across the cement, iron and steel, and petroleum refining industries due to the addition of SCR, FGD, and DCC systems upstream of the amine unit. The authors then quantified the financial impact on public health by applying the projected reductions in NO_X, SO_2, and $PM_{2.5}$ to the U.S. Environmental Protection Agency's (EPA) Co-Benefit Risk Assessment (COBRA) Health Impacts Screening and Mapping tool. The estimated public health savings were substantial. For example, implementing amine PCC with pollutant mitigation at a specific cement plant in the Mid-Atlantic region was projected to yield an annual public health benefit approaching $200 million. A key finding from the study was that, when public health benefits were included, most cement plants and petroleum refineries under consideration became economically viable projects.

However, concerns arise regarding the methodology employed in the study. The analysis applied uniform emission reductions of 75.1% for NO_X, 98% for SO_2, and 100% for condensable $PM_{2.5}$ to all identified facilities based on emissions data reported to the National Emissions Inventory (NEI). The NO_X and SO_2 reductions were derived from the EPA's post-2011 New Source Performance Standards for pulverized coal power plants, while the $PM_{2.5}$ reduction was assumed. These reductions were applied uniformly to all existing emissions from the studied facilities without consideration of site-specific emission control technologies already in place.

A more rigorous approach would have been to determine the required pollutant concentrations for amine solvent operation and then calculate the necessary reductions to meet those specifications, as was done by Kuramochi et al. (2012).

[109] G2 solvents reduce regeneration energy demand by 20-40% when compared to MEA.

Furthermore, the study does not account for additional emissions resulting from the combustion of natural gas to generate the steam required for amine units.

The assumption that SCR and FGD systems would be universally installed is also questionable. For example, it is unlikely that SCRs will be installed at cement plants due to the operational temperature requirements and PM constraints associated with SCR performance. In a cement plant, an SCR would need to be installed between the penultimate and final cyclone stages (see Figure 2). However, at this stage, the flue gas contains excessive PM, which would coat and deactivate the SCR catalyst. Consequently, if an SCR were added, PM control would need to be implemented both before the SCR and after the final cyclone, where PM is reintroduced into the flue gas. Given these challenges, SNCR, which does not rely on catalysts, is the more common NO_X control technology at cement plants.

This conclusion is further supported by published data from pilot studies on cement plants. The Brevik plant[110], for example, does not have an SCR installed (Knudsen *et al.*, 2014). Instead, the plant employs an SNCR. Despite the higher NO_X concentrations compared to systems with SCR, pilot trials conducted by Aker prior to the commitment to install a commercial-scale unit did not indicate substantial solvent degradation, and nitrosamine levels were measured below the detection limit of 0.03 µmol/Nm³. Additionally, the authors of this literature review are aware of another cement plant that will be using SNCR for NO_X control upstream of a commercial scale amine-based capture system. Therefore, for large-scale cement flue gas projects, it is evident that SNCR, rather than SCR, is likely preferred for NO_X control.

Furthermore, FGD systems may not be required at cement plants if the limestone in the raw meal removes SO_2 to levels consistent with BAT-EALs. Limestone is inherently an alkaline material and naturally absorbs SO_2. This mechanism is commonly relied upon in cement plants, except in cases where the kiln fuel contains a high sulfur content.

Finally, the assumption that SCR would be installed on FCC units is also misguided. The FCC unit at TCM is equipped with a SNCR (Bade *et al.*, 2014) rather than an SCR unit, and achieves NO_X concentrations lower than those typically observed from coal-fired power plants, see Table 23. Furthermore, amine emissions have been reduced to below 2 ppmv using a combination of a two-stage water wash, dry bed, and BDU for CESAR1, as well as the Aker ACC emission control system for S26 (Bade *et al.*, 2014; Hume *et al.*, 2022). If these amine emission levels are low enough to avoid NSA and NA formation at appreciable levels in an adequately dispersed plume, then upgrading to SCRs may not be necessary.

Consequently, while the study provides valuable insights into the potential public health benefits of amine PCC, its findings should be interpreted as indicative rather

[110] Introduced in Section 5.2.4

than definitive. Nonetheless, it is the first study to appropriately highlight the importance of incorporating public health considerations into the evaluation of carbon capture projects.

The second grey literature study was conducted by the Clean Air Task Force (CATF) in 2023 (J. Brown *et al.*, 2023). Similar to the previous work, this study quantified the health benefits of implementing amine PCC based on the reduction of co-pollutants. However, rather than applying a generalized approach or analyzing a large number of facilities, this study focused on four specific cases: two real-world cement plants and two real-world FCC units. The reported reductions in emissions varied across the facilities, with NO_X decreasing by 2–73%, SO_2 by 99%, and PM by 93–97.5%. This study determined the reduction at each site based on the performance of the co-pollutant control technologies believed to be necessary upstream of fictional amine units. The corresponding health benefits were estimated to range from $61 million to $687 million per year at these sites.

The report acknowledges and estimates a slight increase in volatile organic compounds (VOCs) resulting from amine emissions and amine degradation products. However, these emissions do not appear to be included in their health benefit estimate. The author states that these emissions were not considered because NSAs at analogous projects, TCM and Petra Nova, were at detection limits or below safety thresholds. A publication (J. D. Brown *et al.*, 2023) released in parallel with the complete study confirmed that emissions associated with natural gas boiler flue gas[111] were considered in this study, unlike in the preceding Great Plains study. It assumed NO_X emissions around 1.6 ppmv[112] for the auxiliary boiler which is certainly the best case scenario.[113] This study represents a significant improvement over the earlier Great Plains study. However, certain assumptions in the report may have led to an overestimation of the benefits. For example, at one of the FCC units, it was assumed that an existing SNCR would be upgraded to an SCR. This assumption is potentially flawed, as explained in the analysis of the Great Plains report. The cost of the upgrade may not be justified if NO_X degradation and NSA formation due to NO_X can be addressed with other strategies. Additionally, it was assumed that wet ESPs would need to be installed at both FCC units to reduce PM. It is likely true that FCC units require controls to prevent aerosol nuclei from increasing amine emissions[114] and that reducing submicron PM entering the amine unit can be an effective strategy. However, wet ESPs may not be the optimal technology for this purpose[115]. Instead, BDUs and dry beds (trickle beds) have demonstrated effectiveness at TCM. The total PM reduction

[111] Used to generate steam for the amine reboiler
[112] Calculated from the report by these authors.
[113] See section 6.7
[114] See Section 6.5.4
[115] See Section 6.10

achieved by a BDU is expected to be comparable to that of a wet ESP, suggesting that this assumption may not have significantly impacted the results.

Similarly, the report assumed that the addition of wet ESPs are necessary at a cement plant. However, the report notes that filter systems are already in place at these facilities, which are likely baghouse filters. It is possible that the existing bag filter could effectively control mist-phase emissions from aerosol nuclei. Consequently, again, the estimated benefits may be overstated.

Nevertheless, given that the role of wet ESPs in aerosol formation is not widely understood, it would be inappropriate to be overly critical of this report. Overall, the methodology is robust, and this study, along with the work by Kuramochi et al. (2012), serve as excellent templates for future research.

Furthermore, one key theme exemplified by the CATF study is that the magnitude of co-benefits is highly dependent on the age of a facility and whether it has avoided upgrading to BAT controls due to "grandfathering" allowances. For example, one FCC unit examined in the study had more advanced SO_2 controls than the other, and as a result, it's SO_2 reductions were less substantial because the facility had already undergone upgrades to meet BAT standards.

The third study was a follow-up to the CATF study, conducted by Frontiers in Public Health. This study reported significant reductions in $PM_{2.5}$ emissions following the deployment of amine-based CCS technology at the ExxonMobil Baton Rouge Refinery, Dow Chemical Louisiana, CF Industries Donaldsonville Nitrogen Complex, and the International Paper Co. Mansfield Mill.

However, the study contained a critical methodological flaw: it assumed that the percentage reduction in $PM_{2.5}$ emissions established in the CATF report for FCC and cement flue gas was applicable to heat and power flue gas at these sites. This assumption is incorrect for two reasons: (1) the emission profiles of these applications differ significantly, and (2) more importantly, the analysis failed to account for existing emission control technologies at the studied facilities, potentially leading to overestimated reductions.

Both the CATF study and the Frontiers in Public Health study highlight an important aspect of health co-benefits: they are highly dependent on the facility's location. For example, the facility with the highest estimated public health benefit of $687 million per year was located 35 miles northeast of a densely populated U.S. city.

7 Gap Analysis

Based on the literature review conducted in this study, several gaps have been identified. It is important to acknowledge that no literature review can comprehensively cover all existing publications on a given topic. Therefore, the gaps highlighted here are based solely on the body of literature reviewed as part of this work. As a best practice, researchers are encouraged to conduct targeted literature reviews specific to their intended experimental studies prior to initiating new research efforts.

7.1 Limited Data for Pilot Projects in Heavy Industry

Experts in the PCC community recommend conducting pilot studies on facility-specific flue gas streams before full-scale deployment (Gibbins, Lucquiaud and Samson, 2024). Due to the complex interactions among various solvents, flue gas contaminants, and degradation products, a universal solution does not exist for all flue gas streams, not even for flue gas streams from the same application, such as coal-fired power plants.

Although, as demonstrated in the preceding sections, many general conclusions can be drawn from pilot plant studies of PCC amine units, these studies also yield insights specific to each application. Therefore, publicly funded studies with open-source data are of immense value. Table 23 illustrates how much of the PCC research to date has focused on coal-fired power plant applications, followed by significant attention to natural gas-fired power plants, with comparatively less focus on WtE and FCC applications. However, there is a notable lack of publicly available data on PCC deployment in heavy industries such as cement, steel, and iron production.

One could argue that these industries are sufficiently similar to previously studied sectors. However, it is likely that heavy industry presents unique challenges that only real-world pilot plant testing can adequately address. For example, will SO_3 be an issue in cement plants or will sintering plant dust catalyze accelerated amine oxidation, leading to increased emissions when a PCC amine plant is deployed? These are just some of the questions that researchers may need to investigate. Ultimately, the challenge lies in the unknown, identifying and addressing factors that are not yet fully understood.

A pilot plant study was conducted at the Brevik cement plant. However, because the solvent used in this study is proprietary, the specific reasons for its strong performance remain unclear. Heidelberg Materials is constructing full-scale amine solvent PCC units at its Brevik, Lengfurt and Edmonton cement plants. However, as these projects utilize proprietary solvents, it is unlikely that in-depth performance data will be made publicly available.

To bridge these knowledge gaps, ongoing research projects, such as AURORA, will provide valuable data to the research community. Furthermore, the U.S. Department of Energy (DOE) is deploying a mobile emissions testing unit and funding front-end

engineering design (FEED) studies as well as pilot plant studies for PCC deployment in cement plants and steel mills (US DOE, 2024). It is hoped that data from these efforts will be publicly shared to benefit the entire research and industrial community.

However, it is important to remember that pilot projects studies do not always reflect the emission dynamics of full-scale commercial operations. Pilot studies, for instance, often exclude data from operational "incidents" on the basis that they are non-representative of normal performance. While this practice helps isolate the intended performance of the technology, it may understate the range of actual emissions that would occur in sustained commercial deployment. Researchers are encouraged to publish all available data when performing studies.

7.2 Limited Studies on Co-Pollutants on Non-PCC Projects

As discussed in Section 5.1, two promising technologies for the cement and iron and steel industries are LEILAC and pre-combustion capture from BFG, respectively. However, no data on the impacts of these projects on co-pollutants have been found.

The authors speculate that both projects will have implications for co-pollutant emissions. For example, the LEILAC process decouples the flue gas streams from the pre-calciner and kiln in a cement plant. This means that kiln flue gas may not pass through the pre-calciner for preheating (though in retrofitted plants this may still be an option). Limestone in the cement meal is known to absorb SO_X, and the loss of this natural emission mitigation mechanism may lead to increased SO_X emissions unless dedicated SO_X controls are applied to the kiln flue gas.

Similarly, the DMX Dunkirk Demonstrator project will remove CO_2 from BF gas, thereby increasing its energy density. This could result in higher flame temperatures and, thus, will require properly designed burners to avoid impacts on thermal NO_X formation.

Researchers and technology providers are urged to consider these implications as early as possible in the development cycle. A cautionary precedent can be observed in the formation of NSA and NA from amine-based solvents in PCC applications. As these technologies scale, issues that were once minor laboratory footnotes can resurface as critical concerns. Tackling such problems early in the design phase can significantly mitigate subsequent public-health and environmental concerns.

7.3 Calcium Looping to Minimize Co-Pollutant Emissions from Power Plants and Cement Plants

When co-pollutant emissions are taken into account, some technologies that have received less attention for large-scale CCS deployment compared to amine scrubbing may, in fact, be more attractive due to their potential air quality co-benefits. For example, calcium looping applied to power plants and cement plants may contribute to reductions in SO_X and NO_X emissions.

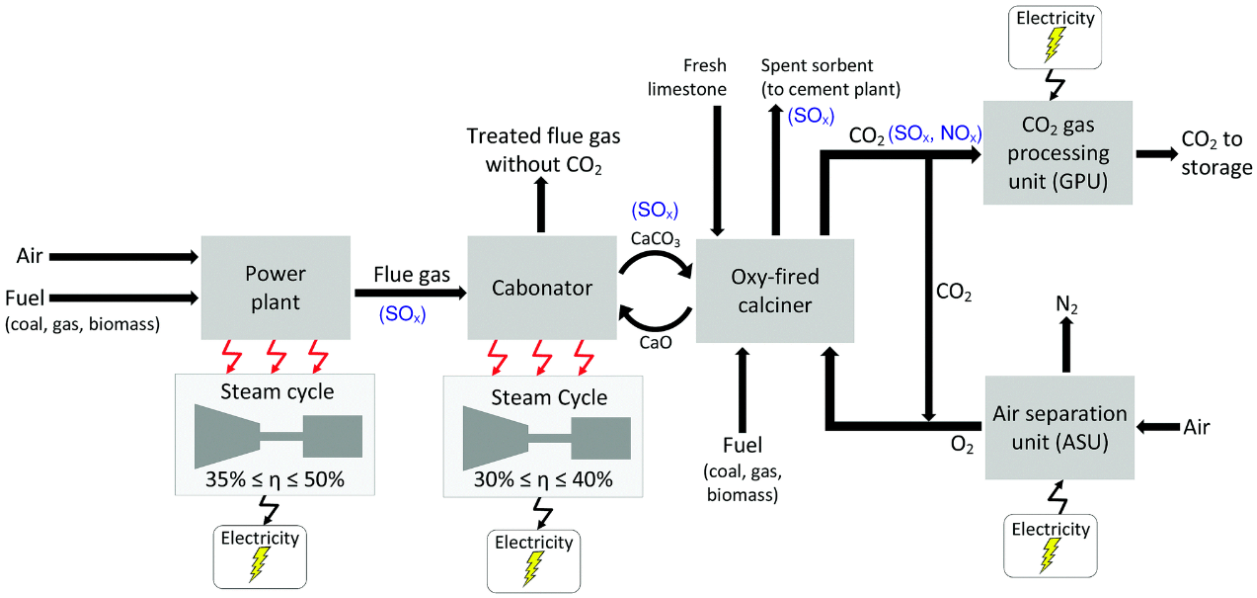

Figure 22 - Calcium looping within a post-combustion capture process, adapted from (Bui, Adjiman, *et al.*, 2018).

As illustrated in Figure 22, CaO can absorb SO_2 from power plant flue gas in the carbonator. In addition, NO_X and SO_2 emissions resulting from fuel combustion in an oxy-fired calciner may be absorbed or concentrated in the CO_2 off-gas stream. A study specifically dedicated to these and other co-pollutant impacts of calcium looping would provide valuable insights for assessing its overall environmental performance.

7.4 Adsorption Technologies Impact on Co-Pollutant Emissions

Co-pollutants can be co-adsorbed on solid media engineered either for direct CO_2 capture or for water removal in the dewatering of CO_2 streams. In CO_2 adsorption media, this has the potential to deliver co-benefits through the simultaneous capture of additional pollutants. By contrast, when the objective is water removal, these co-pollutants may be released to the atmosphere together with desorbed water during regeneration. A systematic understanding of co-pollutant affinities for solid sorbents is therefore critical to assessing the broader environmental implications of deploying these technologies.

7.5 Particulate Matter is not Gravimetrically Measured in Pilot Plant Studies

Efforts by Great Plains, Clean Air Task Force, and Frontiers (discussed in Section 6.11) to quantify public health benefits rely on accurate measurements of PM reduction in PCC amine units. However, ironically, such data are not readily available from modern PCC pilot plants. As discussed in Section 6.1.4, pilot plant studies have predominantly focused on particle size distribution for mist-phase aerosol nuclei research rather than on total gravimetric PM. Given that total gravimetric PM reduction is a critical input for public health benefit assessments, it is recommended that researchers prioritize its measurement before and after the amine unit.

This statement does not diminish the relevance of particle number concentrations and particle size distribution in understanding aerosol formation and their potential implications for health. Smaller particles are generally more harmful per unit mass because of their ability to penetrate deeper into the respiratory system. Nevertheless, current methodologies for assessing public health benefits rely primarily on gravimetric measurements rather than on particle counts or size distributions. Thus, gravimetric studies are required. These studies should employ established methods, such as EPA Method 5 (for filterable PM) and EPA Method 202 (for condensable PM), which offer straightforward and effective approaches. Additionally, these measurements can be integrated with other ongoing research activities to enhance the overall understanding of PM emissions from PCC amine units.

Although gravimetric measurements provide adequate input for many of the epidemiological methodologies employed by organizations such as the Great Plains Institute, the Clean Air Task Force, and Frontiers, they may not fully capture health risk. Gravimetric methods quantify particulate matter on a mass basis, but health outcomes are often more strongly correlated with particle size and number concentration. Smaller particles pose a disproportionately higher health risk due to their greater ability to penetrate deep into the respiratory tract and, in the case of ultrafine particles, to translocate into the circulatory system. Organizations working to quantify public health benefits should look for ways to consider this when performing their studies.

7.6 Higher Fidelity Methods for Analyzing Aerosol Formation

Other instrumentation techniques, such as Condensation Particle Counters (CPCs) in conjunction with Differential Mobility Analyzers (DMAs), are capable of detecting and classifying particles as small as ~1 nm in diameter. The role of particles of this size in aerosol formation remains poorly understood, as such methods have rarely been applied to studies of amine-based PCC emissions. For example, freshly nucleated H_2SO_4 particles, which can subsequently evolve into mist-phase aerosol emissions, originate at the nanometer scale. Advancing understanding of the conditions under which these particles form and grow would be critical for developing targeted strategies to mitigate their environmental and operational impacts. Furthermore, the origin of aerosol particles can be determined with the use of a scanning electron microscopy (SEM) and energy dispersive x-ray analysis (EDX). This has only been used in a few pilot plant studies (Moser *et al.*, 2015).

7.7 Public Health Benefit Studies

Several shortcomings in the existing efforts by Great Plains, the CATF, and Frontiers were identified in Section 6.11. However, these studies could play a crucial role in encouraging and organizing funding for CCS projects. However, to ensure credibility and withstand academic scrutiny, these studies should be conducted with rigorous methodology and transparency.

To enhance the robustness of these studies, it is recommended that they adopt the methodology of Kuramochi et al. (2012), which provides a comprehensive framework for assessing CCS deployment. However, the Kuramochi et al. study has certain limitations and is now outdated. Specifically, it does not reflect current technologies or updated solvent specifications now considered representative of modern CCS systems. Additionally, the Kuramochi et al. study did not attempt to quantify public health benefits in monetary terms.

Therefore, it is recommended that this study be updated to reflect state-of-the-art technological advancements and further extended to incorporate economic valuations of public health benefits, following the methodology outlined by Great Plains, CATF, and Frontiers.

7.8 Health and Environmental Impacts of Other Waste Streams

As discussed in Section 6.3.2, acid washes are an effective strategy for mitigating amine and NH_3 emissions. However, the disposition of this waste stream has not been extensively studied in the literature. The stream is expected to contain dissolved ammonium sulfate, ammonium salts, unreacted dissolved amines, and unreacted acid. While this stream can be neutralized and sent to a wastewater treatment plant, the environmental impact of unreacted dissolved amines could be significant, particularly due to the potential presence of NSAs.

A 2016 FEED study by Shell for the Peterhead CCS project concluded that treating this waste stream was not feasible and that incineration was the preferred disposal method (Shell U.K. Limited, 2016). A recent environmental permit application for the Protos Energy Recovery Facility in the UK states that the acid wash stream will be transported off-site for further treatment, recovery, or disposal (Environment Agency, 2024c). This effectively leaves all disposal options open. Consequently, as noted in a previous review (Gibbins, Lucquiaud and Samson, 2024), this literature review has also found no published experimental work on the optimal disposal methods for this waste stream.

The authors recommend characterizing this waste stream with a particular focus on identifying NSA content to assess whether it can be safely neutralized and discharged into the environment. Additionally, further research into the recovery of ammonium sulfate as a fertilizer could be promising. Given that acid washing is a highly effective emissions mitigation measure, widespread adoption may justify further investigation into reuse opportunities for this waste stream.

Finally, the composition of the TEG and mole sieve regenerator vent streams have likely been overlooked in previous studies until it was highlighted in this review. A more detailed understanding of the potential health and environmental implications associated with this point source is warranted and represents an area in need of further research.

7.9 The Impact of Varying Bulk Gas Flowrates on Co-Pollutants

The ability to ramp amine-based PCC plants up and down in response to transient bulk gas flow rates has been studied in the context of the power industry (de Koeijer, Aasen and Hamborg, 2014; Bui, Tait, *et al.*, 2018). And, some studies have noted that changes in power plant load do impact amine and ammonia emissions (Moser, Wiechers, Schmidt, Monteiro, Goetheer, Charalambous, Saleh, van der Spek, *et al.*, 2021). However, a comprehensive and dedicated study on the implications of such variations in bulk gas flow rates for co-pollutant formation and emissions have not been performed. This represents an important area of study that warrants significant attention in both the power industry and the industries considered in this report.

7.10 Emission Spikes During Reclaiming

During reclaiming, the elevated temperatures can accelerate solvent degradation and cause short-term increases in emissions (e.g., NH_3). As discussed in section 6.6.1, N_2O emissions may also occur during reclaiming. A targeted study comparing stack emissions during steady-state operation versus active reclaiming would clarify the magnitude of these effects and whether modifications to the reclaiming process or supplemental controls during reclaiming are warranted.

7.11 NSA and NA at Receptors in Industrial Clusters

Permit applications for amine-based carbon-capture projects typically assess plume-based formation of NSA and NA using existing measured background concentrations of co-pollutants. In industrial clusters, however, widespread deployment of amine-based PCC will create cumulative impacts that are not captured by project-by-project assessments. Moreover, ambient background concentrations of NSA and NA cannot presently be established empirically with routine monitoring, making reliable baseline specification difficult.

Accordingly, project-level plume modeling should incorporate cumulative contributions from other permitted and reasonably foreseeable projects to estimate total impacts at receptors. This requirement could pose a material burden to CCS deployment where earlier projects have already consumed a significant share of allowable receptor exposure.

To provide clarity and consistency, regulators should undertake forward-looking, cluster-level analyses. Clear guidance on allocation of allowable impacts across projects, and on proportionate mitigation where needed, would protect public health without unduly hindering CCS deployment.

7.12 Greater Clarity on the Sources of Heat and Power for Carbon Capture

As shown in Section 6.7, the choice of heat and power supply for operating carbon-capture plants has a major influence on net NO_x emissions. It is not realistic to assume that all sites will electrify the duty with heat pumps or electric boilers or use CHP. Nor is it reasonable to assume that sites will use poorly controlled auxiliary boilers. In practice, the selection is site-specific and depends on factors such as economics (CAPEX/OPEX, fuel prices), grid reliability and marginal emissions, existing steam and power infrastructure, required steam conditions and turndown, local NO_X attainment status and permit limits, and the host facility's overall energy balance.

A focused study of industrial clusters would therefore be valuable. Such a study should document the decision framework and quantify NO_X outcomes for plausible options, including: (i) integration with existing boilers/HRSGs (with or without SCR), (ii) a dedicated auxiliary gas boiler with modern low- NO_X burners and SCR, (iii) electric boilers or heat pumps using marginal grid electricity, (iv) CHP, and (v) waste-heat recovery or hybrid approaches. Results should report both annual totals and short-term emission rates, with sensitivities to operating profile and grid decarbonization.

7.13 NO to NO_2 Ratio for Cement Plants and FCCs

The 95/5 rule (≈95% NO, 5% NO_2 by volume) commonly used for coal-fired power-plant stacks is often assumed to apply to other sectors. However, in CATF's report an NO_2/NO_x fraction of 0.40 was used for an FCC unit based on real-world refinery data, which conflicts with observations at TCM, where $NO_2/NO_x \approx 0.05$, consistent with the 95/5 rule. A systematic survey of available measurements for cement kilns and FCC units would clarify the true range of NO_2/NO_x fractions and determine whether the variability is indeed this large, thereby improving future estimates of the NO_x impacts of amine-based PCC deployment.

7.14 Limited SO_3 Emission Reporting

As shown in section 5, SO_3 is not commonly reported to regulators by emitters. Because SO_3 is a key indicator of aerosol emissions, it would be an invaluable data point for regulators and the research community in planning future amine-CCS deployment. Requiring emitters to pre-emptively provide SO_3 data may be perceived as government overreach. However, the financial burden on emitters would be minimal, while the potential benefits to the CCS community, through improved understanding of secondary aerosol formation and regulatory planning, would be substantial.

7.15 Particulate Matter Formation Due to NH_3 Slip

It is well established that NH_3, in the presence of CO_2 and moisture, can form $(NH_4)_2CO_3$ and NH_4HCO_3 (Park *et al.*, 2008), both of which may act as aerosol nuclei. If an SCR or SNCR system is installed upstream of an amine-based capture unit with the objective

of removing NO_2, this interaction could inadvertently generate aerosol particles before the flue gas enters the absorber. A similar phenomenon may also result from NH_3 formed from degradation within the amine unit itself. To date, no studies have explicitly attempted to identify $(NH_4)_2CO_3$ and NH_4HCO_3 in this context; however, its presence could be verified using SEM or EDX analysis, as outlined in Section 7.6.

8 Synergies with Generic Pollutant Mitigation Technologies

8.1 Existing Co-Pollutant Reductions

The installation of amine-based carbon capture units can lead to reductions in certain co-pollutant emissions. In many jurisdictions, the implementation of CCS will likely prompt facilities that currently operate without BAT to upgrade to BAT-level emissions controls both to comply with regulatory requirements and to reduce amine degradation[116].

In all cases, SO_2 emissions are expected to be reduced to below BAT-AELs, often achieving removal efficiencies exceeding 99%. This is because SO_2, if not removed upstream, will be absorbed by the amine solvent, forming HSS, thereby accelerating solvent neutralization and increasing the cost and frequency of solvent reclaiming. As such, pre-emptive removal of SO_2 is both a technical and economic necessity.[117]

Depending on the method used to generate heat and power to operate an amine plant, a modest decrease in NO_X emissions beyond BAT-AEL may also be observed. This could occur through the selective removal of NO_2, using additives such as thiosulfate in a DCC or dedicated pre-scrubber[118]. However, since NO_2 typically accounts for less than 5% of total NO_X, the overall impact on NO_X emissions will be minor. Moreover, recent findings from Niederaussem have challenged the assumption that NO_2 control is necessary for all solvent systems, particularly with stable blends such as CESAR1.[119]

For PM, the amine unit may act as an effective removal device if upstream controls are not already operating at high efficiency.[120] However, if BAT PM controls (e.g., baghouse filters or electrostatic precipitators) are already in place, the amine unit may no longer provide additional benefit. In some cases, it may even contribute to increased emissions of CPM through aerosol formation and mist-phase carryover, potentially exceeding the levels achieved by conventional BAT technologies.

8.2 Ammonia Slip Reduction

The use of an acid wash downstream of the water wash introduces an operational synergy with upstream SCR and SNCR units. Acid washing effectively captures residual basic compounds, including NH_3, which means that more aggressive NH_3 injection rates can be used in the SCR and SNCR without increasing the risk of ammonia slip to the atmosphere.

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[116] See Section 6.10
[117] See Section 6.4.3
[118] See Section 6.5.7
[119] See Section 6.5.6
[120] See Section 6.4.1

This added flexibility can improve NO_X removal efficiency, particularly in cases where SCR catalyst performance is declining or flue gas conditions are variable. By serving as a polishing step, the acid wash allows operators to prioritize NO_X abatement without being constrained by strict NH_3 emission limits.

8.3 Liquid Waste Incineration in Cement Kilns

It has previously been proposed that reclaimer waste be routed to cement kilns, where the organic components can be incinerated and metals agglomerated into the clinker (Roberts et al., 2005). A similar strategy could plausibly be extended to acid wash waste streams, particularly given their relatively low volume. While this concept appears technically feasible, the authors are not aware of any published studies or project proposals explicitly exploring this pathway.

9 Conclusions and Recommendations

A general conclusion can be drawn that when an amine-based PCC system is installed at a facility that lacks BAT for a particular co-pollutant, a reduction in that pollutant's emissions is likely due to the additional control measures implemented as part of the PCC project. However, in practice, facilities that have already adopted BAT are more likely to be prioritized for PCC deployment, as this can significantly reduce capital investment requirements and they are more likely to be newer, more state-of-the-art plants. The following section therefore focuses on the potential impacts of PCC systems on co-pollutant emissions beyond what is typically achieved through BAT controls.

9.1 Qualitative Assessment of Emissions Changes for Identified Projects

Building on the analysis presented in Section 6, this section provides a qualitative assessment of the expected changes in co-pollutant emissions for carbon capture projects deployed beyond BAT. The assessment considers the four project archetypes identified in Section 5 and is based on the reviewed literature and engineering judgment.

Table 26 – Summary of the expected change in co-pollutant emissions due to the deployment of CCS project archetypes

	Change in Co-Pollutant Emissions due to Deployment (Confidence)				
Project Archetype	**SO_2**	**NO_X**	**PM**	**NH_3**	**Solvent & Degradation Products**
Solvent on Cement Flue Gas	Decrease **(High)**	Decrease to Increase **(Low)**	Decrease to Increase **(Low)**	Decrease to Increase **(Low)**	Increase **(High)**
Solvent on Blast Furnace Gas	No Impact to Decrease **(Low)**	No Impact to Increase **(Low)**	No Impact to Decrease **(Low)**	No Impact **(Low)**	No Impact **(High)**
Solvent on FCC Flue Gas	Decrease **(High)**	No Impact to Decrease **(Low)**	Decrease **(High)**	Decrease to Increase **(Low)**	Increase **(High)**
Direct Separation Reactors [a]	Decrease to Increase **(Low)**	No Impact **(Low)**	No Impact to Decrease **(Low)**	No Impact **(Low)**	Not Applicable **(High)**

[a] DSR systems in cement plants are expected to be deployed in parallel amine-solvent based PCC system for the residual CO_2 emissions arising from DSR heating requirements and from the kiln combustion gases. Therefore, all air quality impacts identified for the "solvent on cement flue gas" archetype are likewise applicable to these parallel PCC systems.

Table 26 summarizes the expected direction of change (increase, decrease, or no impact) for key co-pollutants associated with each archetype, along with an assigned

confidence level reflecting the strength of evidence supporting each conclusion. This qualitative assessment does not directly infer potential public health or environmental impacts but rather characterizes the likely direction of co-pollutant emissions resulting from CCS deployment. The confidence level reflects the authors' judgment based on the strength of evidence available in Section 6. In cases where supporting research is limited or speculative, a "low" confidence level is assigned.

9.1.1 Sulfur Dioxide

In PCC systems, it is almost certain that SO_2 emissions will decrease significantly. This reduction is largely driven by the need to minimize solvent nuetralisation and reduce reclaiming frequency and cost. As described in Section 6.5.8, operators typically aim to reduce SO_2 concentrations to near-zero levels before the flue gas enters the absorber. Therefore, both cement PCC and FCC PCC projects are expected to achieve substantial reductions in SO_2 emissions.

Pre-combustion projects (e.g., blast furnace gas capture) may also achieve modest SO_2 reductions when H_2S is present and co-absorbed in the amine unit along with CO_2. In some processes, H_2S is removed separately and subsequently utilized as a fuel. In such cases, SO_2 will still be emitted to the atmosphere. Because this study did not identify the predominant fate of the captured H_2S under this configuration, the resulting impact was classified as "No Impact to Decrease."

Conversely, the LEILAC process may result in a modest increase in SO_2 emissions in non-retrofit configurations. This potential increase arises from the reduced contact between kiln flue gas and the raw meal, which in conventional kilns provides a degree of dry scrubbing through the absorption of acidic gases. However, if the implementation of LEILAC is accompanied by new wet FGD systems with higher removal efficiencies than the baseline dry scrubbing effect, an overall reduction in SO_2 emissions could still be achieved. Additionally, alternative process configurations have been proposed that may allow the dry scrubbing function to be preserved. Given these competing possibilities, the confidence level in any projected SO_2 outcome remains low.

9.1.2 Nitrogen Oxides

Cement PCC projects may experience either an increase or a decrease in NO_x emissions depending on the source of heat and power for the process, primarily due to the use of auxiliary boilers or CHP units to supply steam for amine system regeneration. This conclusion is based on a simplified engineering estimate presented in Section 6.7. Until studies are conducted that predict the most likely forms of heat and power to be employed, the confidence level for this estimate remains low, and further site-specific

modelling is recommended. Upgrades from SNCR to SCR systems are considered unlikely.[121].

Pre-combustion capture projects may also see increased NO_X emissions due to the ammonia- or amine slip from the amine unit which is subsequently combusted in downstream units. Additionally, if the flue gas energy content increases, thermal NO_X formation may also increase. However, these conclusions are based primarily on engineering judgment, as supporting studies were not found.

FCC PCC projects are expected to show minimal change in NO_X emissions. This assumes that energy for the PCC unit is provided by existing infrastructure, such as refinery CHP systems, and that any exported energy offset is replaced by low-NO_X fuels or renewables. As with cement projects, upgrades to NO_X control systems (e.g., SCR) are not expected. There may be a small decrease due NO_2 induced degradation by the amine solvent.

For LEILAC, no significant change in NO_X emissions is anticipated provided that fuel type and consumption remain constant. However, due to the slightly lower heat transfer efficiency in the pre-calciner when using a DSR compared to a traditional cement pre-calciner, a modest increase in NO_X formation is possible. Any change in fuel type, particularly the use of higher-nitrogen fuels or alternative fuels, could further alter the emission profile. As such, NO_X emissions associated with LEILAC are expected to remain similar to baseline, but may vary depending on site-specific fuel and process choices.

9.1.3 Particulate Matter

PM emissions from cement PCC projects are generally expected to remain stable. However, in installations where upstream baghouses already remove a significant fraction of particulate matter, there is a potential risk of downstream increases in fine PM or aerosol emissions. This could occur if mist or aerosol formation takes place within the carbon capture system, an issue that has been observed in other sectors, such as waste-to-energy applications (see Section 6.4.1). The extent to which this may affect overall PM emissions in cement applications remains uncertain, and further research is required to characterize this risk.

In pre-combustion capture projects, PM emissions may modestly decrease. This potential reduction is attributed to the installation of additional particulate control equipment upstream of the amine unit, which could reduce the amount of PM entering subsequent combustion steps. However, in the absence of detailed site-specific studies, this outcome remains speculative.

In FCC PCC projects, PM emissions are likely to decrease due to the need for polishing filters, mist eliminators, or other filtration systems to protect the amine process from

[121] See Section 6.7

contamination. As baghouses are not standard BAT for FCC units in some regions, the installation of BDUs or similar equipment is likely with the addition of amine capture.

For LEILAC-2, PM emissions from fuel combustion are expected to remain unchanged or increase slightly for the same reasons discussed in relation to NO_X emissions, namely, that combustion conditions and fuel composition are assumed to remain constant. However, in one of the proposed configurations for the DSR[122], dust from the cyclones is no longer vented directly to the atmosphere. Instead, this dust will need to be captured and removed upstream of the CO_2 compression system to prevent operational issues, such as seal failures. As a result, this change in dust handling could lead to a net decrease in PM emissions.

9.1.4 Ammonia

NH_3 emissions are likely to increase in PCC projects in the absence of acid wash systems. However, if acid wash systems are implemented, they will capture both ammonia slip from upstream SNCRs and ammonia produced through degradation. In doing so they may ultimately reduce pre-existing NH_3 emissions[123]. Confidence in the direction of change remains low here because it is not yet clear is acid washes will be widely adopted.

For the solvent on blast furnace gas archetype, any NH_3 exiting the amine unit will likely be combusted in downstream units, thereby eliminating the potential for atmospheric release. However, a slight increase in NH_3 emissions remains plausible if SCR or SNCR systems downstream of the combustion process are operated more aggressively to mitigate increased NO_X formation[124]. This increase is likely negligible and only applicable to facilities equipped with SCRs or SNCRs. The discussion is included here for completeness.

In the case of one configuration[125] of DSR designs, existing SNCR systems will need to be retrofitted to treat the unmixed flue gas from both the kiln and the pre-calciner. Additional NH_3 may be required to mitigate the slightly elevated NO_X emissions[126], which may, in turn, lead to increased ammonia slip. As above, this increase is expected to be negligible but, again, is included here for completeness.

9.1.5 Solvent and Degradation Compounds

Solvent and degradation product emissions are an inherent feature of PCC systems. However, as shown in Table 23, emissions can be effectively controlled. For example,

[122] See Figure 3
[123]See Section 8.2
[124] See Section 9.1.2
[125] See Figure 3
[126] See Section 9.1.2

primary amine, secondary amine, and amine degradation product emissions can all be reduced to sub-ppm levels, while NSAs can be maintained below detection limits.

Solvent emissions are not expected from pre-combustion capture projects, as solvent-laden streams are combusted in downstream units (SEPA, 2015). The LEILAC process does not utilize chemical solvents and is therefore not associated with solvent emissions.

9.1.6 Quantifying SO_2 Reductions

SO_2 reductions for PCC projects are highly likely based on quantifiable data. These data can be used to calculate percentage reductions; however, readers should exercise caution when applying these reductions universally, as baseline emission values are EU BAT-AELs, and values in other regions may differ. Table 27 summarizes this calculation.

Table 27 – Predicted SO_2 Emission Reductions from Amine-Based CCS Deployment at Cement Plants and FCC Units

Scenario	Baseline Emissions (mg/Nm^3)	Emissions after Amine-Based CCS Deployment (mg/Nm^3)	% Reduction [a]
SO2 at Cement Plants	50-400	<1	> 98.4% to 99.8%
SO2 at FCC	100-1200	<1	> 99.1% to 99.9%

[a] Assumes that flue gas at cement plants and FCC units decreased by 20 vol% and 13.2 vol%, respectively, due to CO_2 removal.

In the opinion of the authors, sufficient data were not available to calculate reductions for other pollutants.

9.2 Recommended Future Research

Based on the preceding sections, the authors first present a set of general future research recommendations, followed by targeted recommendations identified through the gap analysis and the qualitative assessment of emission changes.

9.2.1 General

- An acknowledged limitation of this report is its reliance on academic and open-source literature, rather than on regulatory permit applications, which contain a wealth of information on emission profiles. A future study focusing exclusively on permit applications for large-scale amine-based PCC projects would provide a valuable complement to the present work. This data may allow for the expansion of Table 27 to other co-pollutants.
- The dry bed (trickle bed) at Niederaussem has demonstrated exceptional effectiveness in mitigating mist-phase emissions when CESAR1 is applied as a PCC solvent to coal-fired flue gas. In contrast, achieving comparable emission reductions at TCM required both a dry bed (trickle bed) and an upstream BDU. This raises the question of whether FCC flue gas presents greater operational challenges than coal-derived flue gas, or whether specific process conditions at Niederaussem account for the superior performance of the dry bed (trickle bed) alone, or whether special operating parameters at TCM affected the

performance. A comparative analysis of operating conditions, such as absorber temperature profiles, could help clarify the factors critical to the successful application of dry bed (trickle bed) systems.

- Further research is recommended to validate and expand upon the findings of Moser et al. regarding solvent aging and its influence on degradation and emissions.[127] In particular, studies should investigate whether long-term aging similarly affects other solvent systems. Ultimately, such work may support the relaxation or removal of NO_2 control and reclaiming requirements for amine-based capture plants which would decrease the cost of deployment.
- This review conducted only a preliminary analysis of liquid and solid waste streams. A focused literature review on this topic may yield additional findings and help identify optimal disposal or reuse strategies not captured in the present study.
- The present review considered only direct emissions associated with PCC operation and did not incorporate a full life cycle perspective. Consequently, it may underestimate total emissions in scenarios where indirect emissions are substantial. Future studies should incorporate life cycle analysis to more accurately capture the net environmental impact of CCS systems and to inform optimization of capture plant design and integration strategies.

9.2.2 Gap Analysis

Recommendations for future research based on the gap analysis presented in Section 7 are listed here.

- Publicly funded pilot-plant projects with open-source data for heavy industry should be undertaken to address the current knowledge gap on co-pollutant emissions in these sectors.
- For projects such as LEILAC-2 and 3D, dedicated studies are needed to quantify the impact of deployment on co-pollutant emissions. These technologies may have consequences on co-pollutant emissions. Early characterization can prevent unforeseen regulatory or operational challenges.
- Studies on the impacts to co-pollutants resulting from the deployment of calcium looping and adsorption technologies would be valuable for assessing the total social benefits of these approaches. Historically, research has focused primarily on economic performance.
- Current pilot studies predominantly focus on aerosol and mist-phase behavior, while overlooking filterable and condensable PM mass measurements. Future pilot-plant campaigns should therefore integrate gravimetric PM sampling at the absorber inlet and outlet to better support health impact assessments. These measurements should be conducted alongside analyses of trace components,

[127] See Section 6.5.6

particle size distribution, and particle number concentration across the 6 nm to 5 µm particle diameter range. Alternatively, health studies could develop strategies to incorporate currently employed methodologies into their frameworks. In either case, this disconnect must be addressed.

- Alternative methods (e.g., CPC, DMA, SEM, and EDX) for analyzing and characterizing particulate matter are available, and their application would enhance the understanding of aerosol formation.
- A public health benefits study should be performed using Kuramochi et al.'s (2012) or a similar rigorous methodology to establish the change in co-pollutant emissions. Then, quantification of the benefits can be performed using the methods (the COBRA software tool) outline in the Great Plains, CATF, and Frontiers studies. This will strengthen the credibility of public health benefit claims.
- Experimental data are needed on the chemical composition of acid wash waste, particularly with respect to NSAs and NAs. This will help determine the feasibility of treatment options such as incineration, neutralization, or reuse. And, research into ammonium sulfate recovery for fertilizer production may also offer pathways for beneficial reuse.
- Further research should investigate the composition and potential health impacts of emissions from TEG or mole sieve regeneration vents, which may carry residual amines. This emission point is typically overlooked and may pose localized risks depending on stack design and treatment strategies.
- The impacts on co-pollutant emissions and their interactions with amine-based PCC units during transient events, such as flue gas flow-rate changes and solvent reclaiming, should be investigated to ensure that these effects are not significant enough to warrant additional strategies or controls during such events.
- Regulators are encouraged to proactively predict total NSA and NA concentrations at receptors located near industrial clusters. Such assessments may inform the tightening of allowable limits for permit applicants in order to prevent cumulative impacts that could hinder the deployment of subsequent plants.
- NO_x emission impacts are highly dependent on the heat and power sources selected for amine-based PCC plants. Studies that more precisely quantify these sources would provide significant value in improving understanding of the true NO_x emission impacts.
- There are conflicting data on NO/NO_2 ratios for NO_x emissions from industrial sources, and uncertainties also remain regarding SO_3 emissions. Targeted studies that quantify these emissions across multiple plants would provide more representative emission rates and improve the reliability of impact assessments.

- It has been hypothesized that $(NH_4)_2CO_3$ and NH_4HCO_3 may form upstream of amine units and contribute to mist-phase emissions. A study in which significant quantities of NH_3 are introduced upstream of an amine unit, followed by analysis of the particulate matter formed, would help determine whether this concern is significant.

9.2.3 Qualitative Assessment of Emission Changes

Expanding the results of the qualitative assessment made in Table 26 to quantitative assessments is recommended. It is recommended that focus is first put on the areas where an increase in emissions is possible and the confidence is low. These are summarized as follows:

- Direct Separation Reactors may increase SO_2 emissions by reducing lime / SO_2 interaction (depending on how the process is integrated).
- Solvent on Cement Flue Gas may increase NO_X emissions.
- Solvent on Blast Furnace Gas may increases NO_X emissions.
- Solvent on Cement Flue Gas may increases PM emissions.
- Solvent and Cement and FCC Flue Gas may increase NH_3 emissions.

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11 Appendix 1 – TRL Definitions

TRL 4 – Technology validated in lab

The technology is tested in a laboratory environment with components integrated to demonstrate that they work together. This is a proof-of-concept stage but in a controlled setting.

TRL 5 – Technology validated in relevant environment

The system or component is tested in a relevant operational environment that mimics real-world conditions as closely as possible, though not necessarily in a fully operational setup.

TRL 6 – Technology demonstrated in relevant environment

A prototype or system model is tested in an environment that closely resembles actual conditions, reducing risks before moving to real-world deployment.

TRL 7 – System prototype demonstration in operational environment

The prototype is tested in the actual operational environment, demonstrating its ability to function in real-world conditions but possibly with some support or monitoring.

TRL 8 – System complete and qualified

The system is fully developed and tested in its final form, with all functions verified. It has been proven to work under real conditions and is ready for operational deployment.

TRL 9 – System proven in operational environment

The technology is fully operational, deployed, and has been successfully used in real-world applications with consistent performance.

12 Appendix 2 – Table 2 Citations

Citation #	Source
1	(*CCUS Projects Database - Data product*, 2025)
2	(*CO2RE - Global CCS Institute*, 2025)
3	("Project Leilac-1 - CO_2 Process Emissions Research," 2025)
4	(*Brevik CCS | SLB Capturi*, 2025)
5	Not Used
6	(*CNPC Plans Largest CCUS-EOR Project*, 2023)
7	(*Coffeyville Gasification Plant Details*, 2025)
8	(*Linde Signs Long-Term Agreement to Supply Clean Hydrogen to Dow's Path2Zero Project in Canada*, 2024)
9	(*Enid Fertilizer CO2-EOR Project Details*, 2025)
10	(*Xinjiang Dunhua Petroleum Technology Co | REALISE-CCUS*, 2025)
11	Not Used
12	Not Used
13	(*Donaldsonville Complex*, 2025)
14	(*Linde to Invest $1.8 Billion to Supply Clean Hydrogen to OCI's World-Scale Blue Ammonia Project in the U.S. Gulf Coast*, 2023)
15	(*Air Products Announces Multi-Billion Dollar Net-Zero Hydrogen Energy Complex in Edmonton, Alberta, Canada*, 2021)
16	(*Next-generation carbon capture technology | Carbon Clean*, 2025)
17	(Svante, 2023)
18	(Jelen, 2023)
19	Not Used
20	Not Used
21	(*IFPEN | CO2 capture: launch of Dinamx, an industrial pilot demonstration project for the DMX process*, 2025)
22	(*Successful demonstration in Dunkirk of the CO2 capture DMX process*, 2025)
23	Not Used
24	Not Used
25	(*中国最大CCUS示范项目在宁夏开建 - 生态中国网*, 2025)
26	Not Used
27	(*Products*, 2025)
28	Not Used
29	Not Used
30	(Jordal, 2017)
31	(*CO2 capture from cement production | CEMCAP Project | Fact Sheet | H2020*, 2025)
32	(*Go4ECOPlanet*, 2025)
33	(*Heidelberg Materials North America Announces Latest Step in Edmonton CCUS Project*, 2025)
34	(Leefomgeving and TNO, 2022)
35	(*Air Products to Build Europe's Largest Blue Hydrogen Plant and Strengthens Long-term Agreement*, 2023)
36	(IEAGHG, 2018)
37	(Bowerbank and Abdollahi, 2019)
38	(*Air Liquide to build a world-scale CO_2 capture unit to contribute to Rotterdam's industrial basin decarbonization | Air Liquide*, 2023)

39	Not Used
40	(*Circular Economy: TotalEnergies and Air Liquide innovate to produce Renewable, Low Carbon Hydrogen at the Grandpuits Zero Crude Platform*, 2025)
41	(*Circular economy : Air Liquide and TotalEnergies innovate to produce renewable and low-carbon hydrogen at the Grandpuits Zero Crude Platform | Air Liquide*, 2022)
42	(*7.5.2. Weyburn Project*, 2025)
43	Not Used
44	(SINOPEC, 2025)
45	(*Carbon Capture and Storage | Sturgeon Refinery*, 2025)
46	(*Blue hydrogen | Shell Global*, 2025)
47	Not Used
48	(Wang, 2016)
49	(*Linde Starts up Supply of Clean Hydrogen and Captured Carbon Dioxide to Celanese*, 2024)
50	(*Air Liquide's Cryocap™ FG technology | Go4ECOPlanet*, 2025)

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