

TECHNICAL REPORT

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Carbon dioxide capture — Carbon dioxide capture systems, technologies and processes

*Capture du dioxyde de carbone — Systèmes de capture du dioxyde de
carbone, technologies et processus*

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see the following URL: www.iso.org/iso/foreword.html.

The committee responsible for this document is ISO/TC 265, *Carbon dioxide capture, transportation, and geological storage*.

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Introduction

Carbon capture and storage (CCS) is a technology to mitigate climate change. Many demonstration projects have been conducted worldwide, and CO₂ capture is an important process in CCS and is cost and energy intensive.

CO₂ capture in power industry could be classified through pre, post and oxy combustion. Technologies such as chemical and physical absorption, adsorption, and membrane separation are currently under development and are in various stages of maturity from commercial (110 MW)^[1] large-scale demonstrations to laboratory-scale evaluation, and should be delivered at low cost and low energy consumption.

The objectives of this Technical Report are to specify and review existing capture technologies, equipment and processes and comprehend CO₂ capture systems so that this Technical Report can provide stakeholders with the guidance and knowledge necessary to develop a series of standards for CO₂ capture and build consensus on this standardization work in advance.

This Technical Report describes CO₂ capture systems based on published papers and other documents and then summarizes the different issues deemed most important by ISO/TC 265. This includes the following:

- boundary for CO₂ capture systems;
- technologies, equipment and processes;
- CO₂ streams, gas streams and emissions, processes and waste products;
- evaluation procedures for capture performance;
- safety issues on each capture system;
- reliability issues on each capture system;
- management system.

Carbon dioxide capture — Carbon dioxide capture systems, technologies and processes

1 Scope

This Technical Report describes the principles and information necessary to clarify the CO₂ capture system and provide stakeholders with the guidance and knowledge necessary for the development of a series of standards for CO₂ capture. This Technical Report also covers technologies, equipment and processes specific to CO₂ capture from the viewpoints of the international standardization for the implementation of CCS.

The purpose of this Technical Report is to provide guidance for the development of an ISO document related to CO₂ capture as part of a CCS chain. This Technical Report covers CO₂ capture systems applicable to CO₂ emission sources and their respective boundaries, as well as capture technologies, equipment and processes. In addition, it can be used for the development of International Standards under TC 265.

The following issues are to be excluded from this Technical Report:

- industrial use of CO₂;
- compression of CO₂ (not described in detail);
- terminologies not used in this Technical Report.

2 Normative references

There are no normative references in this document.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

3.1

absorbent

substance able to absorb liquid or gas

3.2

affinity

tendency of substances to react with each other

Note 1 to entry: Also defined as the decrease in Gibbs energy on going from the reactants to the products of a chemical reaction.

[SOURCE: IUPAC Compendium of Chemical Terminology]

3.3

air separation unit

unit separating oxygen, nitrogen and other inert gases from air which delivers the required oxygen for gasification or combustion applications in the context of CCS

3.4

alkanolamine

chemical compound that carries hydroxy (–OH) and amino (–NH₂, –NHR, and –NR₂) functional groups on an alkane backbone

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3.5

amine

chemical compound consisting nitrogen atoms bound to hydrogen and/or carbon atoms having the general formula R_3N

3.6

amino acid

any of a class of organic compounds in which a carbon atom has bonds to an amino group, a carboxyl group, a hydrogen atom and an organic side group

3.7

antioxidant

substance that inhibits oxidation or reactions promoted by oxygen, peroxides, or free radicals

3.8

Brayton cycle

thermodynamic cycle that describes the workings of a constant pressure heat engine such as gas turbine engine

3.9

capital cost

sum of direct equipment costs to capture CO_2 which is also known as investment cost or first cost

[SOURCE: IPCC Special Report on Carbon Dioxide Capture and Storage]

3.10

capital requirement

sum of direct equipment costs and indirect costs to capture CO_2

3.11

catalyst

substance that increases the rate of reaction without itself being consumed in the reaction

3.12

CCS energy consumption

total energy used for the development and operation of a CCS project

3.13

chemical absorption

process in which CO_2 is absorbed by chemical reaction

3.14

circulating dry scrubber

type of semi-dry FGD using hydrated lime as chemical reagent which is based on a circulating bed reactor set up to desulfurize the flue gas

3.15

clinker

mass of incombustible matter fused together

3.16

CO_2 capture

separation of CO_2 in such a manner as to produce a concentrated stream of CO_2 that can readily be transported for storage

3.17

CO_2 capture rate

ratio of the captured CO_2 mass flow rate at CO_2 capture system to the inlet CO_2 mass flow rate to CO_2 capture system

3.18**CO₂ processing unit**

group of processes used in the purification of the CO₂ rich gas to a desired CO₂ specification

Note 1 to entry: Also known as compression and purification unit (CPU), CO₂ purification unit (CPU), cryogenic purification unit, gas processing unit (GPU).

3.19**critical pressure**

vapour pressure at the critical temperature

3.20**critical temperature**

temperature above which liquid cannot be formed simply by increasing the pressure

3.21**decarboxylation reaction**

chemical breakdown of compounds containing carbonates

3.22**degradation**

act or process of chemical which makes its functional effectiveness or chemical purity decrease towards the failure to meet the performance of the plant through physical and chemical breakdown or reaction with other substances

3.23**dehydration**

process of removing water from a stream or material

3.24**demineralized water****demin water**

water of which the mineral matter or salts have been removed

Note 1 to entry: Sometimes designated as demin water.

3.25**demister**

device, often fitted with vapour-liquid separator vessels, to enhance the removal of liquid droplets or mist entrained in a vapour stream

3.26**desorption**

release of CO₂ from absorbent or adsorbent

3.27**direct quench**

process where hot gas is cooled by injection of water, cool gas or water immersion

3.28**effluent**

flow of waste material discharged into the environment

3.29**equilibrium**

state of balance between opposing forces or actions that is either static or dynamic

3.30**flash gas**

gas separated from a liquid by pressure reduction

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3.31

flue gas

gases produced by combustion of a fuel that are normally emitted to the atmosphere

3.32

flue gas condenser

process of removing water from the flue gas by cooling

3.33

flue gas desulfurization

equipment normally used in the removal of SO_x in the flue gas by using chemical reagents

3.34

flue gas processing unit

unit of processes used to remove different criteria pollutants (SO_x , NO_x , PM, etc.) from flue gas of boilers or fired heaters

Note 1 to entry: Also known as environmental island, air quality control system (AQCS), gas quality control system (GQCS).

3.35

forced oxidation wet flue gas desulfurization

type of wet FGD using limestone as chemical reagent

3.36

gas turbine

machine in which a fuel is burned with compressed air or oxygen and mechanical work is recovered by the expansion of the hot products

3.37

gasification

reaction that coal, biomass, petroleum coke, or natural gas is converted into a syngas composed mainly of carbon monoxide (CO) and hydrogen (H_2)

3.38

gasifier

reactor in which coal, biomass, petroleum coke, or natural gas is converted into a syngas composed mainly of carbon monoxide (CO) and hydrogen (H_2)

3.39

membrane

permeable solid material that selectively separates the components of a fluid mixture

3.40

mist

stream of liquid in the form of very small drops

3.41

nitrosamine

any of various organic compounds which are characterized by the grouping NNO

3.42

nitramine

any of various organic compounds which are characterized by the grouping NNO_2

3.43

off-gas

gas that is produced as a by-product of a process

3.44**oxy-combustion****oxyfuel combustion**

process involving combustion of a fuel with pure oxygen or a mixture of oxygen and re-circulated flue gas

3.45**oxy-CFB boiler**

CFB boiler using technology based on oxyfuel combustion with recycled flue gas

3.46**oxy-PC boiler**

PC boiler using technology based on oxyfuel combustion with recycled flue gas

3.47**particulate emission**

solid and liquid particles that are by-products of combustion entrained in flue gas exiting the stack of a fossil fueled boiler

3.48**permeability rate**

quantity of flow of gas (or liquid) through a membrane per unit of time and area

3.49**permeance**

measure of gas actually flowing through a membrane per unit of pressure differential

Note 1 to entry: In general, it is expressed in gas permeance units (GPU).

Note 2 to entry: $1 \text{ GPU} = 10^{-6} \text{ cm}^3(\text{STP})/\text{scm}^2(\text{cmHg})$.

3.50**physical absorption**

process where a solvent absorbs a gas physically with pressure and without chemical reaction

3.51**post-combustion capture**

capture of carbon dioxide from flue gas stream produced by fuel air combustion

3.52**power output**

electricity which is produced or supplied from a power plant

3.53**pre-combustion capture**

capture of carbon dioxide following the processing of the fuel before combustion

3.54**pressure swing adsorption**

method of separating gases using the physical adsorption of one gas at high pressure and releasing it at low pressure

3.55**pulverized coal**

finely ground coal

3.56**pulverized coal boiler**

utility boilers using pulverized fuel or coal as fuel

3.57**pulverized fuel**

finely ground solid fuels such as coal or biomass

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3.58

quench

to cool hot gas suddenly

3.59

radiant quench design

design of the process where hot gas is cooled by radiant cooler

3.60

reaction rate

speed of a chemical reaction

3.61

reclaimer

process or unit that regenerates deteriorated absorbent

3.62

recycled flue gas

flue gas recycled to moderate the combustion temperature

3.63

regenerator

see *stripper* ([3.79](#))

3.64

reliability

ability of an item to perform a required function, under given environmental and operational conditions and for a stated period of time

[SOURCE: ISO 8402]

3.65

retrofit

modification of the existing equipment to upgrade and incorporate changes after installation

[SOURCE: IPCC Special Report on Carbon Dioxide Capture and Storage]

Note 1 to entry: See IEA Technology Roadmap: Carbon Capture and Storage.

3.66

saturation

point of a solution condition at which a solution of a substance can dissolve no more of that substance and additional amounts of it will appear as a separate phase at the stable condition

3.67

scrubber

gas liquid contactor device, normally used to remove gaseous and solid emissions from flue gas streams

3.68

selectivity

degree that one substance is absorbed in comparison to others

[SOURCE: US Department of Energy/National Energy Technology Laboratory, Advanced Carbon Dioxide Capture R&D Program: Technology Update, February 2013]

3.69

shift conversion

see *shift reaction* ([3.71](#))

3.70

shift converter

reactor in which the water-gas shift reaction, $\text{CO} + \text{H}_2\text{O} = \text{CO}_2 + \text{H}_2$, takes place

3.71**shift reaction**

chemical formation of carbon dioxide and hydrogen from carbon monoxide and water

3.72**sludge**

semi-liquid (or semi-solid) residue or solids separated from suspension in a liquid in industrial processes and treatment of sewage and waste water

3.73**slurry**

thick, flowable mixture of solids and a liquid, usually water

3.74**solute**

dissolved substance in a solution

3.75**solvent**

liquid substance capable of dissolving CO₂

3.76**sorbent**

substance that absorbs CO₂ or to which CO₂ is adsorbed

3.77**sour shift (reaction)**

shift reaction without removing H₂S or COS

3.78**steam reforming**

catalytic process in which a hydrocarbon is reacted with steam to produce a mixture of H₂, CO and CO₂

3.79**stripper**

gas-liquid contacting device, in which a component is transferred from liquid phase to the gas phase

Note 1 to entry: Can also be referred to as “regenerator” or “desorber”.

3.80**sweet shift (reaction)**

shift reaction after removing H₂S or COS

3.81**syngas**

synthetic gas produced through gasification process

3.82**treated gas**

gas finally discharged from the CO₂ capture process in the emission side after being processed to have a lower CO₂ concentration than the feed gas

3.83**waste water**

water for which there is no use in the process anymore

3.84**water gas shift**

see *shift reaction* ([3.71](#))

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4 Symbols and abbreviated terms

%RH	% relative humidity
AAS	Amino acid salt
ACI	Activated carbon injection
AEP	American Electric Power
AGR	Acid gas removal
AIGA	Asian Industrial Gas Association
AOD	Argon-oxygen decarbonization
AQCS	Air quality control systems
ASME	American Society of Mechanical Engineers
ASU	Air separation unit
A-USC	Advanced ultra-supercritical
BAC	Booster air compressor
BAHX	Brazed aluminium heat exchanger
BAT	Best available technology
BF	Blast furnace
BFG	Blast furnace gas
BFW	Boiler feed water
BOF	Basic oxygen furnace (also known as LD or converter)
BOFG	Basic oxygen furnace gas (also known as LDG or CG)
BOP	Balance of plant
BOS	Basic oxygen steelmaking
BREF	Best available technology reference document
BSF	Boiler simulator furnace
BTG	Steam and power generation unit
BTX	Benzene, toluene and xylene (also known as Benzole)
CalEPA	California Environmental Protection Agency
CAP	Chilled ammonia process
CAPEX	Capital expenditure
CAS	Chemical abstract service
CCF	Cyclone converter furnace
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CDA	Circulating dry absorber
CDQ	Coke dry quenching
CDS	Circulating dry scrubber
CEMS	Continuous emission monitoring system
CERC	Cambridge Environmental Research Center
CFB	Circulating fluidized bed
CFR	US Code of Federal Regulations
CG	Converter gas (also known as BOFG or LDG)
CGA	Compressed Gas Association
CIS	Commonwealth of Independent States
CISWI	Commercial and industrial solid waste incinerators
COG	Coke oven gas

COSHHHSE	Control of substances hazardous to health under health and safety executive
CPU	CO ₂ processing unit, compression and purification unit, CO ₂ purification unit or cryogenic purification unit
CSIRO	Commonwealth Scientific and Industrial Research Organization
CTL	Coal to liquids
CW	Cooling water
DAF	Dry ash free
DCAC	Direct contact and after cooler
DCC	Direct contact cooler
DCCPS	Direct contact cooler polishing scrubber
DP	Dew point
DRI	Direct reduction ironmaking
DSI	Direct sorbent injection
EAF	Electric arc furnace
EHS	Environmental, health and safety
EHSM	Environmental, health and safety management system
EIA	Environmental impact assessment
EIGA	European Industrial Gas Association
EOP	Electricity output penalty
EOR	Enhanced oil recovery
EPA (USEPA)	US Environmental Protection Agency
ESP	Electrostatic precipitator
ETP	Energy technology perspectives
EU	European Union
FBC	Fluidized bed combustion
FCV	Flow control valve
FD fan	Forced draft fan
FEED	Front end engineering design
FEGT	Furnace exit gas temperature
FF	Fabric filter or bag filter
FGC	Flue gas condenser
FGD	Flue gas desulfurization
FMECA	Failure mode and effects critical analysis
FOH	Forced outage hours
FOR	Forced outage rate
FTA	Fault tree analysis
GBFS	Granulated blast furnace slag
GCCSI	Global Carbon Capture and Storage Institute
GGBFS	Granulated ground blast furnace slag
GGH	Gas-gas heat exchanger
GHG	Greenhouse gas
GHGT	Greenhouse gas control technologies conference
GOX	Gaseous oxygen
GPU	Gas processing unit
GQCS	Gas quality control system
GTCC	Gas-fired combined cycle

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GTL	Gas to liquids
HAZOP	Hazard and operability
HBI	Hot briquetted iron
HC	Hydrocarbons
HGI	Hard grove index
HM	Hot metal (also known as pig iron)
HP	High pressure
HRC	Hot rolled coil
HRM	Hot rolling mill (also known as HSM)
HRSG	Heat recovery steam generator
HS	Hot stove
HSE	Health, safety and environment
HSM	Hot strip mill
IARC	International Agency for Research on Cancer
ID fan	Induced draft fan
IEA	International Energy Agency
IFA	International Fertilizer Industry Association
IFC	International Finance Corporation
IGCC	Integrated coal gasification combined cycle
IP	Intermediate pressure
IPCC	Intergovernmental panel on climate change
ISO	International Organization for Standardization
JCR	Jumbo coke reactor (also known as SCS)
JT	Joule-Thomson
LCOE	Levelized cost of electricity
LDG	Linz-Donawitz gas (also known as BOFG or CG)
LFO	Light fuel oil
LHV	Lower heating value
LIN	Liquid nitrogen
LM	Ladle metallurgy
LNG	Liquefied natural gas
LOI	Loss on ignition
LOX	Liquid oxygen
LP	Low pressure
LTEL	Long-term exposure limit
MAC	Main air compressor
MCR	Maximum continuous rating
MDT	Mean downtime
MHX	Main heat exchanger
MP	Medium pressure (also referred to as IP)
MTBF	Mean time between failures
MTPY	Million tonnes per year
MTTR	Mean time to repair
NAFTA	North American Free Trade Agreement (include USA, Mexico and Canada)
NEDO	New Energy and Industrial Technology Development Organization
NFBF	Nitrogen free blast furnace

NG	Natural gas
OBf	Oxy-blast furnace (oxygen blown blast furnace)
OBf-PG	OBf processed gas
OBf-TG	OBf raw top gas
OFA	Overfire air
OFO	Overfire oxygen
OHF	Open hearth furnace
OHSAS	Occupational health and safety assessment series
OPEX	Operating expenditure
OPERA	Operational problem analysis
OREDA	Offshore reliability data
OSHA	US Occupational Safety and Health Administration
Oxy-CFB	Oxyfuel combustion — circulating fluidized bed
Oxy-PC	Oxyfuel combustion — pulverized coal
PC	Pulverized coal (also known as powdered coal)
PCC	Post combustion capture
PCI	Pulverized coal injection
PF	Pulverized fuel
PFD	Process flow diagram
PGAN	Pressurized gaseous nitrogen
PHA	Process hazard analysis
PM	Particulate matter
POH	Period of hours
PSA	Pressure swing adsorption
PSM	Process safety management
R&D	Research and development
RCRA	Resource conservation and recovery act
REACH	Registration, Evaluation, Authorization and Restriction of Chemicals
RFG	Recycled flue gas
RIST	Research Institute of industrial science and technology
SC	Supercritical
SCGH	Steam coil gas heater
SCR	Selective catalytic reduction
SCS	Single chamber system (also known as JCR)
SDA	Spray dry absorber
SDI	Sorbent direct injection
SDS	Safety data sheet
SEC	Specific energy consumption
SECARB	Southeast regional carbon sequestration partnership
SM	Secondary metallurgy
SMR	Steam methane reformer
SNCR	Selective non-catalytic reactor
SPC	Specific power consumption
SR	Smelting reduction
STEL	Short-term exposure limit
STP	Standard temperature and pressure

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SWIFT	Structured what-if checklist
TC 265	Technical committee 265
TCM	Technology Center Mongstad
tcs	Tonne of crude steel
TDL	Target detection limit
TGR	Top gas recycle
thm	Tonne of hot metal
tls	Tonne of liquid steel
TPD	Tonnes per day
TR	Technical Report
TRT	Top gas recycle turbine
TSA	Temperature swing adsorber
TWA	Time-weighted average
ULCOS	Ultra-low CO ₂ steelmaking
USC	Ultra-supercritical
VLE	Vapour-liquid equilibrium
VOC	Volatile organic compounds
VPSA	Vacuum pressure swing adsorber
WESP	Wet ESP
WGS	Water gas shift (reaction)
WHO	World Health Organization
WID	Waste Incineration Directive
WSA	World Steel Association
ZR	Zero reformer

5 Carbon dioxide (CO₂) capture system

5.1 General

In 2011, the global CO₂ emission (as reported in References [12] and [228]) was around 33,8 gigatonnes. The power generation sector was responsible for nearly 40 %; while the other industrial sector was responsible for 26 % of the CO₂ emissions.

[Table 1](#) briefly summarizes the breakdown of the emissions from each sector in 2011. IEA has reported that to achieve the greenhouse gas mitigation goal for the 2DS (two-degree scenario) or 450 ppm scenario, CCS is needed to capture both energy- and process-based emissions, that is, it is important to be deployed widely not only in the power generation sector but also in various energy intensive industrial sectors.^[11]

Table 1 — Global CO₂ emissions in 2011

CO ₂ Emission Sources	% of total CO ₂ emission	Remarks
Power	39 %	fossil fuel power plant as large CO ₂ stationary sources
Transport	20 %	
Industry	26 %	iron and steel production, cement production, chemicals, refining and so forth as large CO ₂ stationary sources
Buildings	8 %	
Agriculture and others	7 %	
NOTE See Reference [12].		

CO₂ capture is the first part of the CCS chain. The CO₂ capture system consists of technologies, processes and equipment that enable the separation, capture and processing of CO₂ from gas streams (e.g. natural gas, syngas, process off-gas, flue gas) and make it suitable for transport and storage.

CO₂ can be captured from different stationary point sources such as: fossil fuelled power plants, steel works, cement and lime production, chemicals and petrochemicals processes, pulp and paper mills, natural gas processing plants, oil refineries and fuel conversion plants (i.e. gas to liquids or coal to liquids).

At present, the capture of CO₂ is an established commercial process of different industries such as natural gas processing, ammonia and urea production. Generally, the CO₂ captured from these processes are either released to atmosphere or used as raw materials in the production of other chemicals (i.e. urea, precipitated calcium carbonates) or sold as commodities to the EOR and food industries.

On the other hand, the capture of CO₂ from power plants and other energy intensive industries such as steel and cement, are now being developed and/or demonstrated with the purpose of mitigating CO₂ emissions through CCS.

Table 2 lists large-scale integrated projects for CCS and/or EOR that are operational or under construction and/or commissioning (i.e. execute). The list, provided by The Global CCS Institute, shows projects that capture and store CO₂ amount greater than 0,4 Mtpa, for gas-fired power plants and industrial processes, or greater than 0,8 Mtpa for coal-fired power plants.

Table 2 — Large-scale integrated projects for CCS and/or EOR

Project Name	Project Life Cycle Stage	Country	CO ₂ Capture Capacity (Mtpa)	Operation Date	Industry
Val Verde Natural Gas Plants	Operate	USA	1,3	1972	Natural gas processing
Enid Fertilizer CO ₂ -EOR Project	Operate	USA	0,7	1982	Fertiliser production
Shute Creek Gas Processing Facility	Operate	USA	7,0	1986	Natural gas processing
Sleipner CO ₂ Storage Project	Operate	Norway	0,9	1996	Natural gas processing
Great Plains Synfuel Plant and Weyburn-Midale Project	Operate	Canada	3,0	2000	Synthetic NG production
In Salah CO ₂ Storage	Operate	Algeria	—	2004	Natural gas processing
NOTE See Reference [13].					

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Table 2 (continued)

Project Name	Project Life Cycle Stage	Country	CO ₂ Capture Capacity (Mtpa)	Operation Date	Industry
Snøhvit CO ₂ Storage Project	Operate	Norway	0,7	2008	Natural gas processing
Century Plant	Operate	USA	8,4	2010	Natural gas processing
Air Products Steam Methane Reformer EOR Project	Operate	USA	1,0	2013	Hydrogen production through SMR
Coffeyville Gasification Plant	Operate	USA	1,0	2013	Fertiliser production
Lost Cabin Gas Plant	Operate	USA	0,9	2013	Natural gas processing
Petrobras Lula Oil Field CCS Project	Operate	Brazil	0,7	2013	Natural gas processing
Boundary Dam Integrated CCS Project	Operate	Canada	1,0	2014	Power generation
Agrium Fertiliser Plant using Alberta Carbon Trunk Line (ACTL)	Execute	Canada	0,3–0,6	2015	Fertiliser production
Illinois Industrial CCS Project	Execute	USA	1,0	2015	Chemical production
Quest Project	Execute	Canada	1,08	2015	Hydrogen production through SMR
Uthmaniyah CO ₂ EOR Demonstration Project	Execute	Saudi Arabia	0,8	2015	Natural gas processing
Gorgon Carbon Dioxide Injection Project	Execute	Australia	3,4–4,0	2016	Natural gas processing
Kemper County Energy Facility (formerly Kemper County IGCC Project)	Execute	USA	3,0	2016	Power generation
Abu Dhabi CCS Project (formerly Emirates Steel Industries CCS Project)	Execute	UAE	0,8	2016	Iron and steel production
Petra Nova Carbon Capture Project (formerly NRG Energy Parish CCS Project)	Execute	USA	1,4	2016	Power generation
North West Sturgeon Bitumen Refinery using Alberta Carbon Trunk Line (ACTL)	Execute	Canada	1,2–1,4	2017	Hydrogen production through Lurgi Gasification Process
NOTE See Reference [13].					

5.2 Classification of CO₂ capture systems

As illustrated in [Figure 1](#), CO₂ capture system could be classified according to three different capture routes.

a) Post-Combustion CO₂ Capture: Separation of CO₂ from combustion flue gas.

- b) Pre-Combustion CO₂ Capture: CO₂ removal from syngas obtained from gasification prior to its combustion¹⁾.
- c) Oxyfuel Combustion with CO₂ Capture: Combustion of the fuel in nearly pure oxygen and recycled flue gas to produce a flue gas with highly concentrated CO₂ ready for further processing and purification to a desired CO₂ specification.

Post-combustion

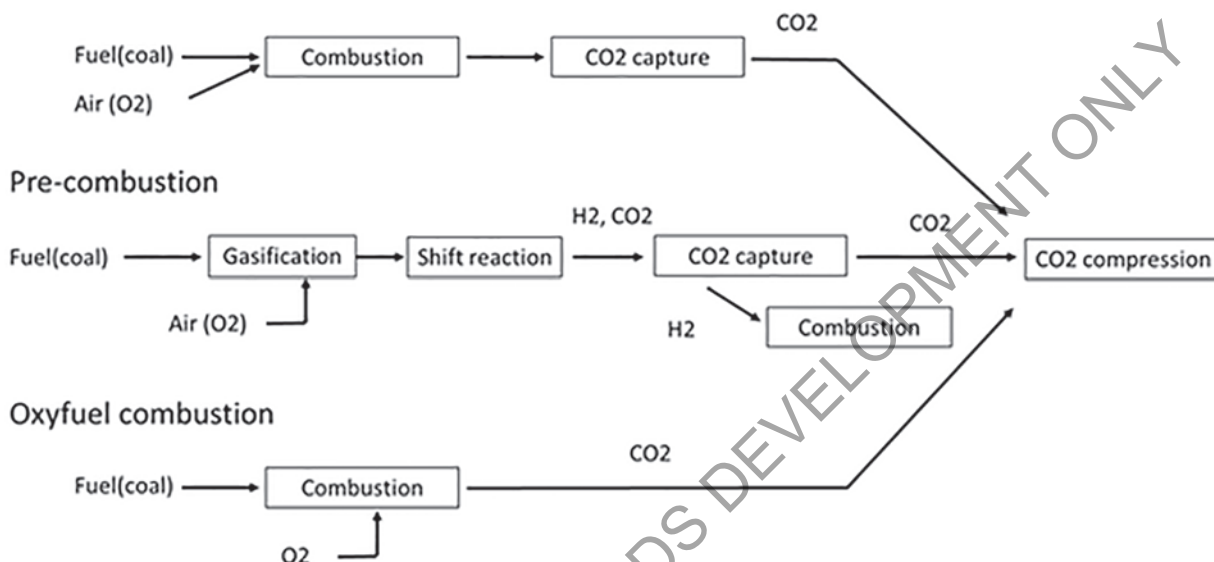


Figure 1 — Different CO₂ capture routes for coal-fired power plant

Detailed description and types of technologies, processes and equipment used in these capture routes applied to power generation industry are presented in [Clauses 7, 8](#) and [9](#), respectively.

On the other hand, CO₂ capture system could also be classified according to the types of CO₂ separation and capture technologies used. This is presented in [Figure 2](#) and explained briefly in [Clause 6](#).

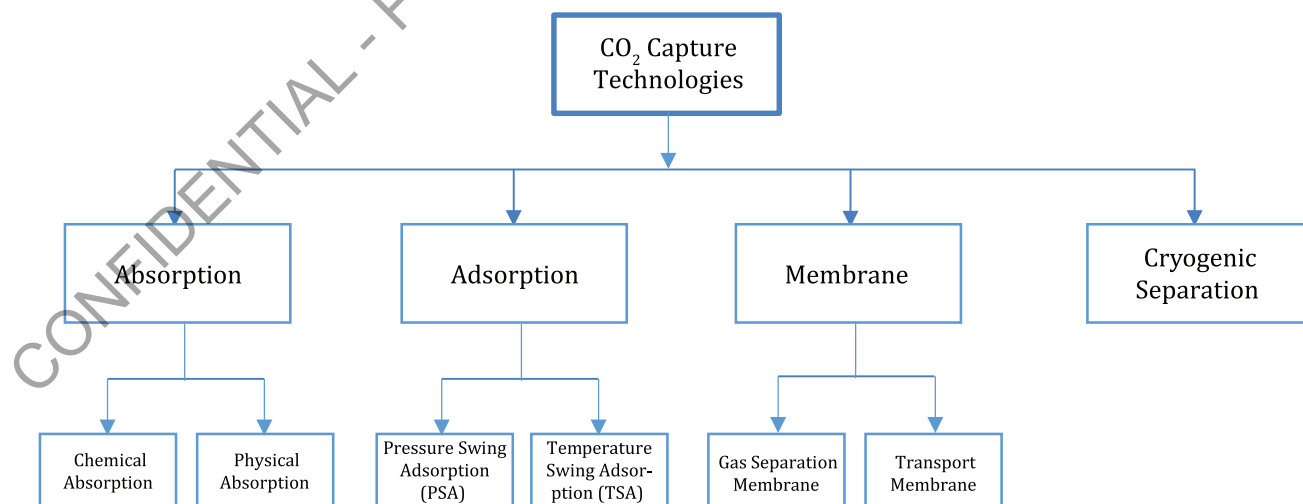


Figure 2 — Types of CO₂ capture technologies

1) Pre-combustion CO₂ capture is not limited to gasification. This could be used as well in natural gas processing when CO₂ is captured before its combustion in power plant or other appliances. Also for off-gases from SMR, ATR or others, removing the CO₂ before combustion.

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For power generation industry, the use of both classifications is straightforward and well-defined. For industrial CO₂ capture, it is preferable to use technologies as the basis for classification. In fact, the definitions of post-, pre- and oxy-combustion are typically referred to power generation and, in some cases, might not be suitable to properly describe an industrial capture system if combustion process is not included.

5.3 System boundary

The system boundary of interest includes the host plant (i.e. power plant or industrial processes) and the CO₂ capture system, up to the point where CO₂ enters the pipeline (i.e. entry point to the CO₂ transport). It should be noted that CO₂ compression is included in the boundary of the CO₂ capture system; however, this is not discussed in detail in this Technical Report.

For post-combustion CO₂ capture, the CO₂ capture system is not integrated into the host plant; thus, system boundary of the capture system could be clearly defined. This could start from the point where the flue gas is taken and enters the flue gas quencher or other flue gas pre-treatment unit. It ends at the point where CO₂ exits from the CO₂ compression flange and enters the CO₂ pipeline. A more detailed discussion of the boundary system for post-combustion capture is presented in [7.1](#).

For pre-combustion CO₂ capture, the CO₂ capture system could be partially integrated into the host plant. There are several variations depending on the technology selected, the defined CO₂ specifications and the capture rate. The boundary between the host plant and the CO₂ capture system for pre-combustion capture is not well defined but could be distinguished. Generally, the CO₂ capture system includes the shift reactor, the acid gas removal unit and the CO₂ compression unit. However, it should be clearly noted that incorporating CO₂ capture in IGCC power plant could also impact other parts of the host plant. A more detailed discussion of the boundary system for pre-combustion capture is presented in [8.2](#).

For oxyfuel combustion CO₂ capture, the CO₂ capture system is fully integrated with the host plant. The system boundary for the CO₂ capture system could not be defined and could not be distinguished. Thus, the whole power plant should be considered as the system boundary, including the air separation unit, boiler, flue gas processing and CO₂ processing unit. Furthermore, it should also be noted that CO₂ compression is integrated into the CO₂ processing unit. A more detailed discussion of the boundary system for oxyfuel combustion with capture is presented in [9.1](#).

In conclusion, the boundary of the CO₂ capture system and the host plant could vary depending on the CO₂ capture technology selected; and the variation to the boundary system could also be site specific. A possible approach in defining the boundary system for a particular project is by using the definition of the project scope as specified in the FEED study.

6 Review and documentation

6.1 General

The following topics will be discussed with regard to the capture technologies applicable to each source:

- a) system boundaries;
- b) technologies, equipment and processes;
- c) CO₂ stream, gas streams and emissions, process and waste products;
- d) evaluation procedure for capture performance including energy penalties (parasitic losses) and other issues;
- e) safety issues and environment impact assessment;
- f) reliability issues;

- g) management system, including interfaces
 - 1) between capture plant and emission source, and
 - 2) with other Working Groups of TC 265.

“System boundaries” is defined as facility boundaries to be described respectively for the above-mentioned CO₂ capture systems based on each of the capture technologies.

“Technologies, equipment and processes,” including outlines of the capture technologies, required equipment and processes are described. Equipment and processes refer to a series of equipment and processes required to implement the aforementioned technologies. Each technology requires unique equipment and processes, which will be discussed in each clause.

“Carbon dioxide stream, gas streams and emissions, process and waste products” will provide information regarding main gas streams containing CO₂, remaining gas streams after CO₂ was captured, especially in pre-combustion capture or industrial gas production, and emissions and waste products from gas streams that occur during those processes. This subclause will also provide information related to chemical compounds occurring in capture processes or chemical compounds in waste materials arising out of such processes.

The treatment of emissions and chemical compounds or waste products that occur in capture processes should, at a minimum, comply with the regulations on the treatment, release, and disposal of chemical substances in respective countries and regions. They should be made innocuous or decreased to the prescribed value or below by incineration or other processes before they are released into the environment.

“Evaluation procedure for capture performance” will provide unique performance parameters and indicators for the capture technologies, to be used as common indicators for comparing the performances of different capture technologies. Information necessary for the relative evaluation should be provided.

“Safety and reliability issues” will describe manifested and potential issues related to safety that are specific to each capture technology and relevant to the goal of disseminating and promoting CCS. Health, safety and environment (HSE) issues will be discussed from the perspectives of facilities, operations, occupational safety and hygiene, and environment. For example, potential emissions and areas of occurrence will be described.

It should be noted that any equipment and facilities related to capture plant must comply with existing laws and regulations in each country or region.

In addition to compliance with laws and regulations relating to chemical processes and others in each country and region, it may be necessary to apply risk scenario analyses such as FMECA, HAZOP, FTA, SWIFT, and OPERA. Since each of these methods has both advantages and disadvantages,^[7] it may be necessary to recommend the most appropriate method(s) for capture processes.

One of the common issues in capture technologies related to HSE is exposure to CO₂. The most probable routes of human exposure to CO₂ are inhalation or skin contact. The need for a risk-based approach is clear from the following two descriptions. CO₂ and its products of degradation are not classified as a toxic substance; are non-hazardous on inhalation, are non-irritant and do not sensitize or permeate the skin. However, chronic effects on humans follow from long-term exposure to airborne CO₂ concentrations of between 0,5 % and 1 % resulting in metabolic acidosis and increased calcium deposits in soft tissues. The substance is toxic to the cardiovascular system and upper respiratory tract at concentrations above 3 %. The product risk assessment process is therefore necessary as with any other chemical use to determine the risk and establish the necessary risk management processes.^[3] Other than CO₂, substances such as amine, oxygen, and hydrogen also need to be considered.^[10]

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Incidentally, no management systems specific to CCS have been established so far. However, as a future item, there is a need to consider the development of management systems in association with the following:

- ISO/TC 176, *Quality management and quality assurance* — for the quality control of personnel, equipment, facility, work environment, etc. for the processes up to CO₂ compression;
- ISO/TC 69, *Applications of statistical methods* and IEC/TC 56, *Dependability* — for reliability and sampling;
- ISO/TC 207, *Environmental management*, ISO/TC 146, *Air quality* and ISO/TC 147, *Water quality* — for environmental management.

Life cycle assessment (LCA) and end-of-life management need to be considered as a management tool of CO₂ capture system.

6.2 Separation processes

There are three general separation processes of CO₂ capture that are integrated into the CO₂ capture route (see Reference [3], Figure 3.2). These details are described in subsequent subclauses.

6.2.1 Separation with sorbents/solvents

The separation is achieved by passing the CO₂-containing gas in intimate contact with a liquid absorbent or solid sorbent that is capable of capturing the CO₂. In the general scheme of diagram a) in [Figure 3](#), the sorbent loaded with the captured CO₂ is transported to a different vessel, where it releases the CO₂ (regeneration) after being heated, after a pressure decrease or after any other change in the conditions around the sorbent. The sorbent resulting after the regeneration step is sent back to capture more CO₂ in a cyclic process. In some variants of this scheme the sorbent is a solid and does not circulate between vessels because the sorption and regeneration are achieved by cyclic changes (in pressure or temperature) in the vessel where the sorbent is contained or by a replacement of sorbent inventory. A make-up flow of fresh sorbent is always required to compensate for the natural decay of activity and/or sorbent losses.

The general scheme of [Figure 3](#) governs many important CO₂ capture systems, including leading commercial options like chemical absorption and physical absorption and adsorption.

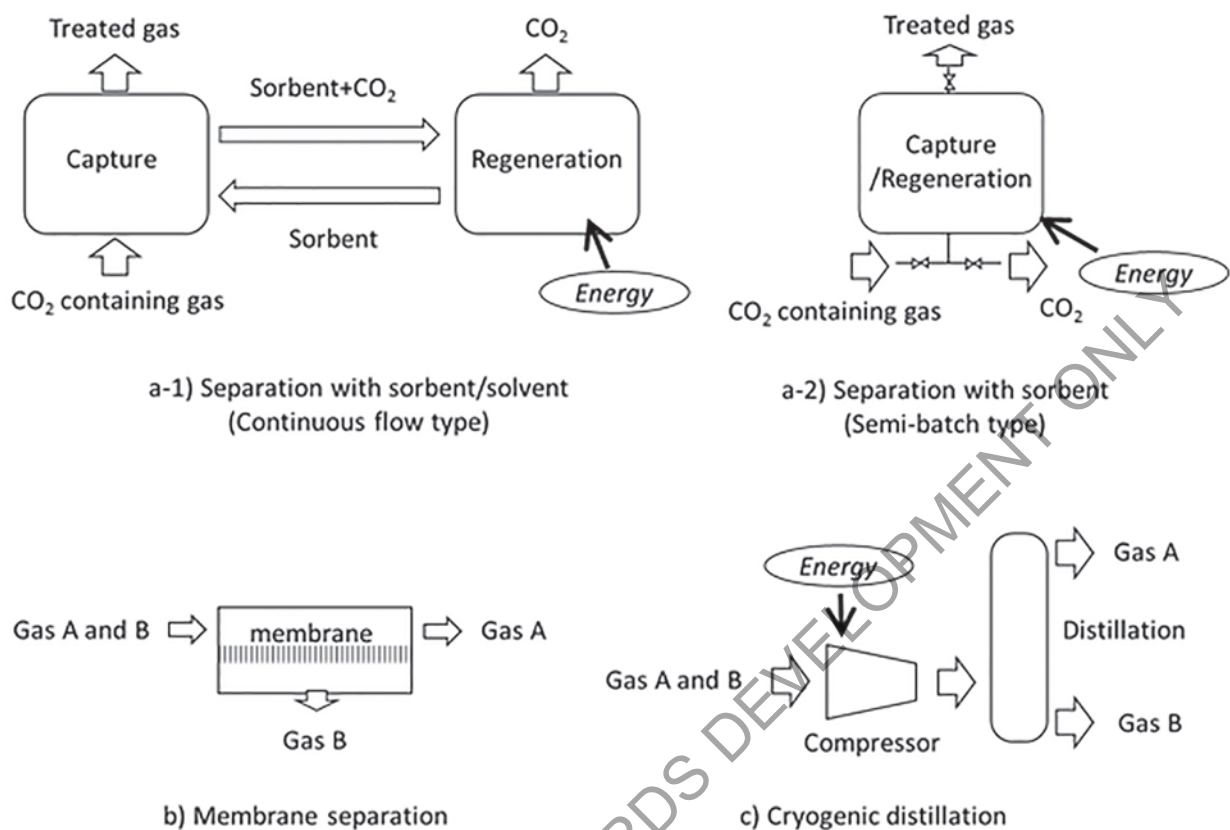


Figure 3 — General scheme of main separation processes of CO₂ capture

Emerging processes based on new liquid sorbents, or new solid regenerable sorbents are being developed with the aim of overcoming the short comings of the existing systems such as high energy requirement, degradation, high investment, and so on. One common problem of these CO₂ capture systems is that the flow of sorbent between the vessels in [Figure 3 a](#)) is large because it has to match the huge flow of CO₂ being processed in the power plant. Therefore, equipment sizes and the energy required for sorbent regeneration are large and tend to translate into an efficiency penalty and added cost. Also, in systems using expensive sorbent materials there is always a danger of escalating cost related to the purchase of the sorbent and the disposal of sorbent residues. Good sorbent performance under high CO₂ loading in many repetitive cycles is obviously a necessary condition in these CO₂ capture systems.

Chemical absorption and physical absorption are well-known as CO₂ separation process with liquid absorbents.

The chemical absorption uses solvents (absorbents) that react chemically to gas to selectively capture target substances. Materials such as amines and potassium carbonate are used in liquid absorbents. Generally speaking, the chemical absorption method is suited for reducing the concentration of CO₂ from tens of percentage points to around 0,1 %, or down to tens of ppm if necessary.

[Figure 4](#) shows a schematic process flow of the chemical absorption method. This approach consists of two major components: the absorber that captures the target substances and the regenerator (stripper) that recycles the absorbent by adding heat to strip the absorbed substances from it. The absorbent circulates between the absorber and regenerator, repeating the absorption and stripping of CO₂.

Many of chemical absorption methods utilize heat to regenerate the solvent.

A typical technology of the chemical absorption method is called amine absorption, which has such a long history and successful track record that it can be considered a mature technology in the gas refining sector. Many CCS projects use the chemical absorption method for CO₂ capture.

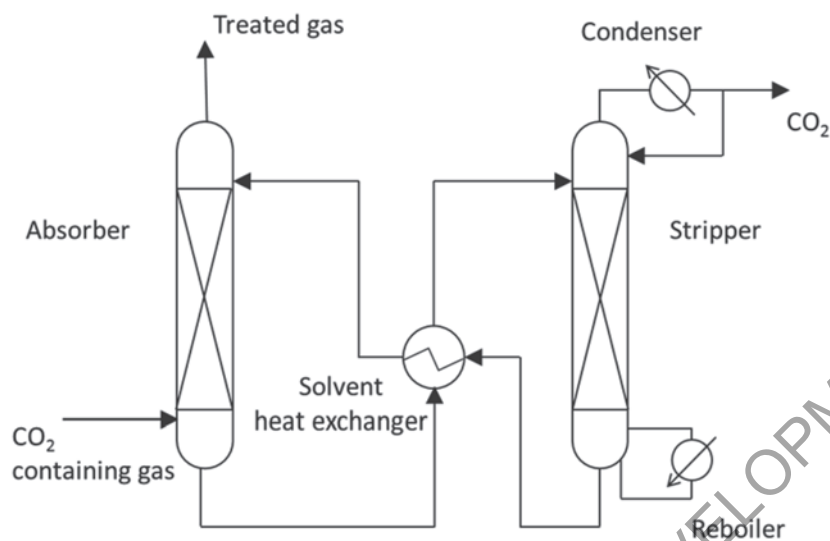


Figure 4 — Schematic flow of chemical absorption

[Annex A](#) shows several examples of the chemical absorption processes.

The physical absorption takes advantage of differences in solubility (without chemical reactions) into the absorbent to physically capture the target gas components, including CO₂. A variety of absorbent products are used, including methanol, propylene glycol and propylene carbonate. This technology is mainly used for the production of syngas-based chemical products as a syngas purification technology and is recently applied to the capture process of IGCC.

A schematic flow chart of the physical absorption process is shown in [Figure 5](#).^[8] As with the chemical absorption method, the system consists of a couple of primary components: an absorber, which absorbs target gas components such as CO₂, and a flash drum and a regenerator, which reduce the pressure or use heat to strip the absorbed gas compounds from the absorbent to regenerate the absorbent. In the physical absorption method, the solubility of gas components in the absorbent is almost directly proportional to the partial pressure of the vapour phase (Henry's law). In addition, solubility increases as the temperature decreases. Thus, it follows that the higher the operating pressure of the absorber and the lower the operating temperature, the more effective the capture of target gas components.

The physical absorption method of industrial application is also a mature technology with a long history.

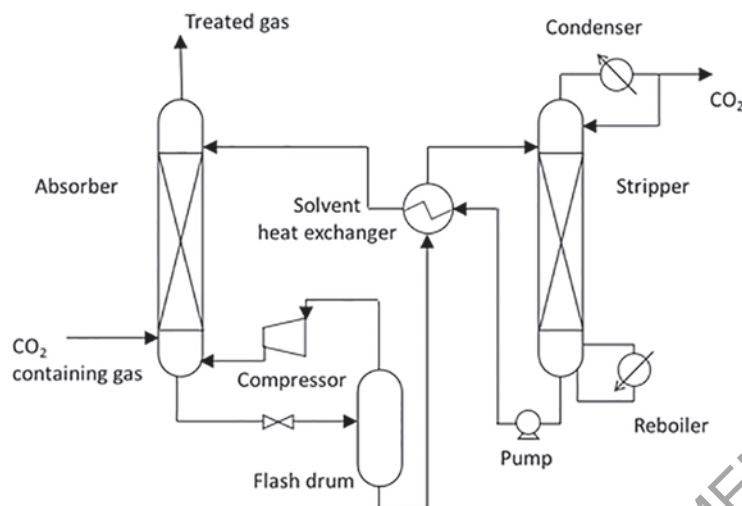


Figure 5 — Flow chart of the physical absorption method

Pressure swing physical adsorption and temperature swing chemical adsorption are known as typical CO₂ separation process with sorbents. Pressure swing adsorption (or sorption) (PSA or PSS) is a technology in which CO₂ is physically adsorbed into the pores of solid sorbent. Once the pressure is lowered, the adsorbed CO₂ is released and captured.

Temperature swing adsorption (or sorption) (TSA or TSS) is a technology in which CO₂ is chemically adsorbed to solid sorbent.

Promising results have also been reported with CO₂ removal from flue gas utilizing a combination of PSA and TSA (PTSA).

6.2.2 Separation with membranes

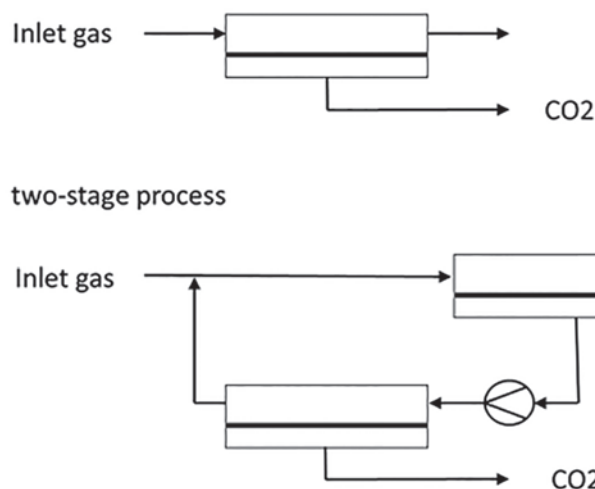
The membrane separation process is a gas separation technology that takes advantage of the differences in the membrane permeability rates among gas components. Because this process separates CO₂ by using as a driving force the pressure difference between the CO₂ inclusive feed gas side and the permeate gas side of a membrane, very little energy is required to separate CO₂ from a high-pressure gas. It is therefore especially effective when the feed gas is at high pressure and contains a high-concentration CO₂.

Membranes in [Figure 3 b\)](#) are specially manufactured materials that allow the selective permeation of a gas through them. The selectivity of the membrane to different gases is intimately related to the nature of the material, but the flow of gas through the membrane is usually driven by the pressure difference across the membrane. Therefore, high-pressure streams are usually preferred for membrane separation. There are many different types of membrane materials (polymeric, metallic, ceramic) that may find application in CO₂ capture systems to preferentially separate H₂ from a fuel gas stream, CO₂ from a range of process streams or O₂ from air, with the separated O₂ subsequently aiding the production of a highly concentrated CO₂ stream. Although membrane separation finds many current commercial applications in industry (some of a large-scale, like CO₂ separation from natural gas), they have not yet been applied for the large scale and demanding conditions in terms of reliability and low-cost required for CO₂ capture systems. A large worldwide R&D effort is in progress aimed at the manufacture of more suitable membrane materials for CO₂ capture in large-scale applications.

A flow chart of the membrane separation process is shown in [Figure 6](#).^[9] The CO₂ inclusive feed gas is introduced upstream, and CO₂ is separated to the lower pressure side through a membrane. To improve the capture rate, a two-stage process recycling permeate gas is adopted.

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The membrane separation process has been used widely in natural gas refineries where the feed gas contains a high concentration (20 %) of CO₂. Research and development on the membrane separation in the IGCC process is also underway.



NOTE Top: Single-stage process; Bottom: Two-stage process.

Figure 6 — Schematic flow of membrane separation process

6.2.3 Separation by cryogenics or flash evaporation

A gas can be made into a liquid by a series of compression, cooling and expansion steps. Once in liquid form, the components of the gas can be separated in a flash or distillation column. In the case of air, this operation is currently carried out commercially on a large scale. Oxygen can be separated from air following the scheme in [Figure 3 c](#)) and be used in a range of CO₂ capture systems (oxyfuel combustion and pre-combustion capture). Refrigerated separation can also be used to separate CO₂ from other gases. It can be used to separate impurities from relatively high purity CO₂ streams, for example, from oxyfuel combustion, and also for CO₂ removal from natural gas or synthesis gas that has undergone a shift conversion of CO to CO₂.

7 Post-combustion capture in the power industry

Post-combustion capture (PCC) is an important and fundamental technology in the context of carbon capture and storage (CCS). PCC is the process which separates CO₂ from a stream of flue gas after combustion, e.g. in a gas turbine or a coal-fired boiler, as well as raw gas, suitable for PCC, from other industrial sources, e.g. refineries, chemical plants.

Coal is an important low-cost fuel source for generating electricity in various regions of the world, especially developing nations. PCC could prove to be a critical technology for minimizing the CO₂ emissions generated by this industry.

7.1 System boundary

7.1.1 Boundary with power plant or other process stream (cooling water, steam, flue gas, product CO₂)

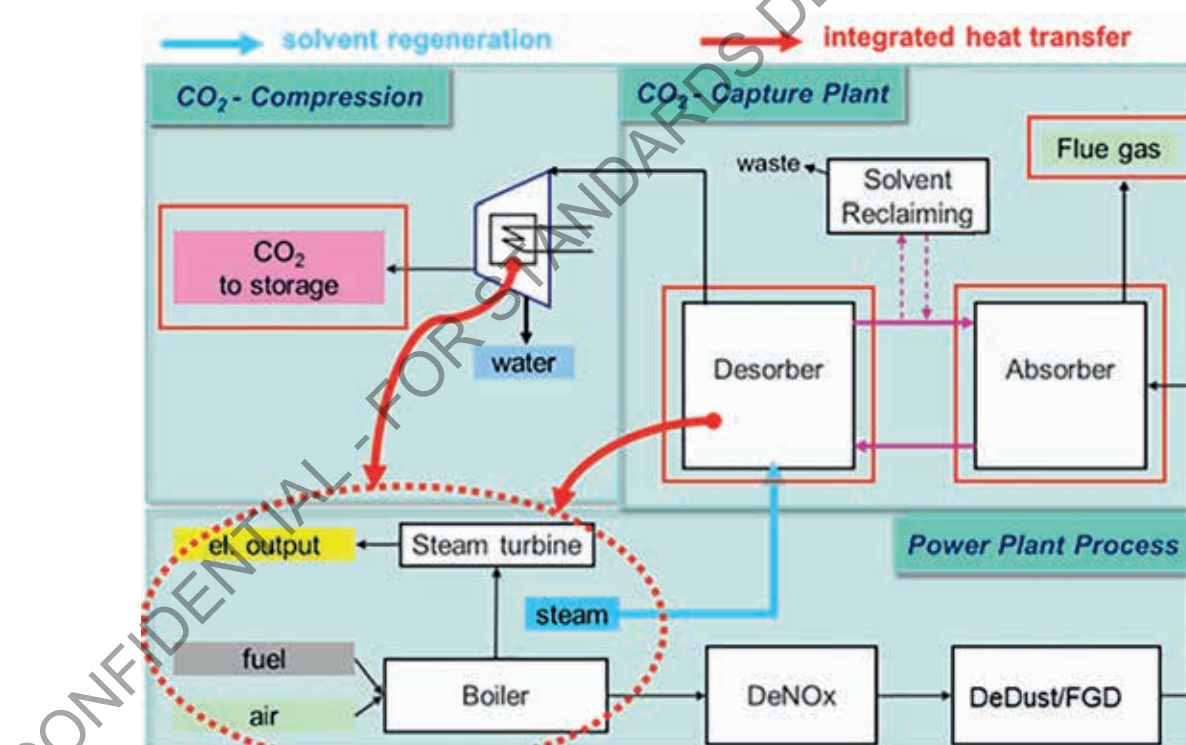
[Figure 7](#) shows an example of the CO₂ capture processes deployed in a thermal power generation plant. [\[14\] Figure 7](#) can be also applicable to the combustion type steam generation plant. Here, the chemical absorption method is used as an example. The captured CO₂, once compressed, is transported using pipelines and mobile carriers, such as ships and trains (not shown in [Figure 7](#)). After the CO₂ has been removed, the flue gas is released into the atmosphere. The underlying principle for CO₂ capture

is the exothermic, reversible reaction between a weak acid such as CO_2 and a weak base such as an alkanolamine. The flue gas to be treated is contacted by the aqueous solution in an absorbing column or vessel where a soluble salt is formed from the reaction between the CO_2 and the base solution.

The flue gas, now depleted of CO_2 , is then released to the atmosphere. The solution, enriched with the CO_2 , is sent to a stripping column or vessel (desorber unit) where, by the addition of heat, the salt formation reaction is reversed and the CO_2 is released and the base solution is regenerated. The lean base solution is recycled to the absorber unit while the CO_2 is made ready for transportation by dehydrating, and if required, deoxygenation and compressing it.

As shown in Figure 7, this subclause covers the flue gas path from the outlet of the flue gas desulfurization (FGD) to the outlet of the absorber unit of the CO_2 capture plant, the solvent system and the CO_2 path up to the outlet of the CO_2 compressor, regardless of the CO_2 capture process used. The associated utilities, waste water and waste products are shown in Figure 8. In some cases, flue gas pre-treatment is required and this should be included within the boundary of the PCC plant.

To support the PCC process, there are interconnections with the power or utility plants steam, cooling water system and other utilities installed (e.g. demin water, plant drainage, pressurized air and others) as shown in 7.4.2. The waste issue related to absorbent purification and/or recovery or total exchange, if cleaning is not possible, including solid waste, is noted in the following subclauses. Red arrow lines in Figure 7 show the possible integrated heat transferred from a capture and compressor part to power plant using the steam condensate of a power plant steam-water cycle, for example, to improve the power plant efficiency utilizing the waste heat in PCC plant.



NOTE See Reference [14].

Figure 7 — Schematic of a pulverized coal-fired power plant with a PCC system and other emission reduction equipment

Figure 8 shows a generic chemical absorption process in detail.[14] A part or all of the flue gas exhausted from the FGD equipment (only relevant for PCC at hard coal-fired power plants) may be routed through a pre-scrubber to adjust the temperature and humidity of the flue gas to fit the optimal conditions of the absorption process. The pre-scrubber may additionally be used to remove SO_2 in the flue gas. The flue gas is then routed to the absorber where CO_2 comes in direct contact with the solvent. The effect is that the vast majority of CO_2 is absorbed by the solvent and capture rates of 90% are achieved.

typical. After the CO₂ is removed, the remaining flue gas is released to the atmosphere. An additional washing step, utilizing a water scrubber installed at the top of the absorber to remove highly volatile substances such as process degradation product and absorbent, may be necessary to ensure that the flue gas released into the atmosphere is in a state that would be acceptable under an Environmental Impact Assessment (EIA). The solvent is returned to the system.

The CO₂-loaded (rich) absorbent is forwarded to the stripper (desorber or regenerator). In the desorption process the solvent is heated, by either Low Pressure (LP) or Medium Pressure (MP) steam depending on the process demand, and extracted from the power plant process to release the captured CO₂. The CO₂-free (lean) solvent is returned to the absorber to absorb CO₂ again. At the stripper gas outlet a mixture consisting of saturated CO₂ is exhausted. The condensate is collected and sent to both the lean solvent inlet at the absorber and the top part of the stripper.

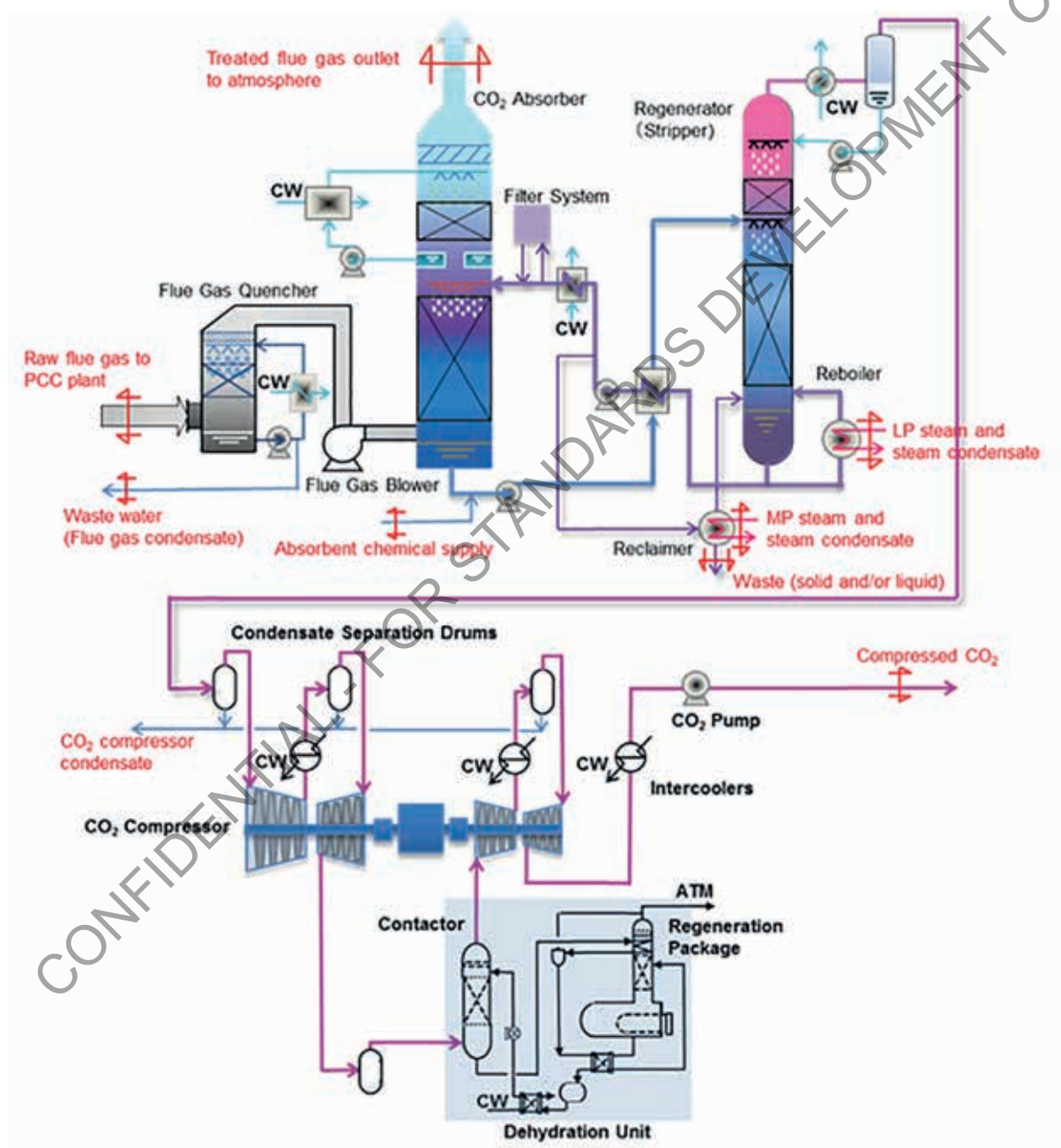


Figure 8 — Generic PCC process flow scheme

7.1.2 Boundary of the PCC plant

Boundary conditions have to be defined for further development of PCC technologies and projects. The following boundaries are considered for a PCC plant:

- raw flue gas to the PCC plant;
- required control and monitor signals to and from a hosted power plant;
- residual flue gas outlet to the atmosphere on top of the absorber or at the inlet flange of a separate stack;
- CO₂ outlet of the separate vent stack or top of the CO₂ absorber to the atmosphere in case of an unplanned disruption in the transport and/or storage chain of CO₂;
- flue gas condensate;
- CO₂ compressor condensate;
- demin water, potable water, firefighting water;
- plant drainage;
- pressurized air, inert gas (e.g. nitrogen);
- steam and steam condensate;
- cooling water supply and return;
- power supply;
- by-product and waste generation (solid and/or liquid);
- absorbent chemical supply.

7.1.3 Boundary with transport and storage of CO₂

The boundary between the PCC plant and the CO₂ transport and storage systems is the downstream flange of the CO₂ compressor.

To avoid backflow effects and to clearly separate battery limits, an open-close valve should be positioned upstream of the downstream flange.

7.2 Technologies, equipment and processes

The following process technologies^[18] are currently available or under development for PCC:

- absorption processes based on chemical solvents;
- adsorption processes and membrane processes are described at the beginning of [Clause 6](#).^[14]

With respect to absorption processes based on chemical solvents, significant progress has been made in the application of the absorption processes to the flue-gas treatment in coal-fired power plants following the publication of the 2005 report on CCS by Intergovernmental Panel on Climate Change (IPCC).^[14] An overview of this technology is included in [7.2.1](#) to [7.2.3](#). The detailed processes are described in References [\[18\]](#) and [\[19\]](#) as examples.

7.2.1 Chemical absorption process based on (alkanol-) amines (amine process) (A)

General explanation is provided in [7.1.1](#).

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According to the International Energy Agency (IEA), notable developments in CCS between 2009 and 2013 include increased experience and confidence with CO₂ capture technologies.^[18] It is believed that the following factors are partly responsible for these developments on CO₂ capture; these statements are partially applicable to all technologies not just amines.

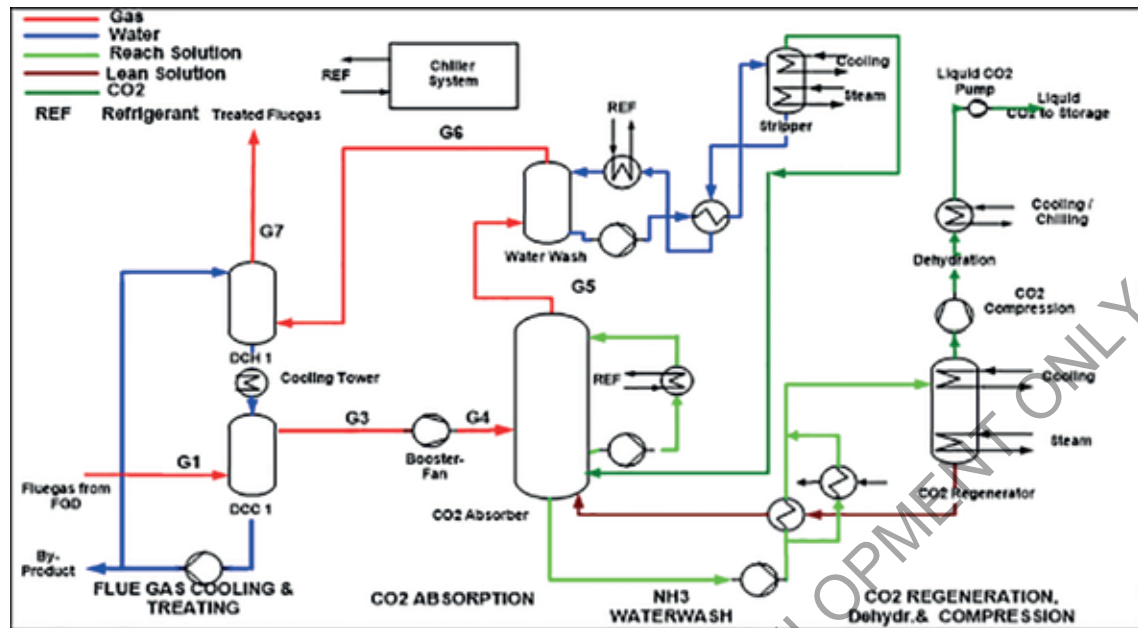
- a) Several PCC technologies have been tested at scales on slipstreams of up to 25 MWe, mainly from coal-fired power plants where the number of commercial references of the medium scale in industrial applications increased.^{[21][22]}
- b) As a result of improvements achieved in processes and absorbents, significant progress has been made in reducing the amount of heat needed per unit of captured CO₂. However, it should be noted that presented values by the technology suppliers are dependent on the specific plant design and operating conditions.^[23] In some processes, a base unit of 2,5 GJ per tonne of captured CO₂,^{[23][24]} or 1,0 tonne of LP steam per tonne of captured CO₂,^[25] has already been achieved or projected. Currently, efforts are aimed toward 2,0 GJ per tonne of captured CO₂.^[28]
- c) Efforts have been made to reduce the performance penalty suffered by a power generation plant when the LP steam used in a PCC is supplied by the turbines of the power generation plant as a source of flue gas. Ways to reuse waste heat from both plants and find an optimal arrangement of the LP steam supply system were pursued so as to improve the efficiency of the power generation plant as a whole, including the PCC process.^[21]
- d) The attention of the EIA has been drawn to the amines contained in the gas streams that are emitted to the atmosphere after being treated by PCC facilities. Initially many research groups, primarily in Norway, have been conducting studies on this subject, resulting in evaluations and improvements of PCC processes such as zero amine emission system^[28] to minimize emissions.^[21]
- e) During the CO₂ capture process the chemical absorbents may react with other contents of the flue gas, e.g. oxygen, NO_x and SO_x, to form heat stable salts which degrade the solvent performance. This may, over time, reduce CO₂ absorption efficiency. To maintain the solvents CO₂ capture capability during operation, reclaiming systems are used. The technology used for solvent reclaiming differs with the process and solvent used. Ammonia-based solvents are reported not to degrade in this manner and do not require reclaiming.

7.2.2 Chilled ammonia process (CAP) (B)

The Chilled Ammonia Process (CAP) treats flue gas from coal-fired power plants, natural gas combined cycle plants, and refinery cat crackers to capture CO₂. CAP consists of seven integrated unit operations.

- a) Direct-contact cooler/heater to condition the primary flue gas stream by removing moisture and absorbing SO₂ (in DCC1) and to prepare the residual flue gas for atmospheric discharge by heating the gas and absorbing residual ammonia in the flue gas leaving the wash system (in DCH1).
- b) Absorber system to capture CO₂ by reaction with a circulated ionic ammoniated solution.
- c) Ammonia water wash system to capture residual ammonia saturating the flue gas discharged from the absorber system.
- d) Regenerator system to release the CO₂ from the rich ammoniated solution and return the lean ammoniated solution to the absorber system for reuse.
- e) Ammonia stripper system to release NH₃ from the wash water and returns it to the absorber system for reuse.
- f) Separate stripper system (not described in [Figure 9](#)) for ammonia recovery from wash water and to limit salt accumulation (primarily ammonium sulfate) in the ammoniated ionic solution.
- g) Compression system to permit transport of the product CO₂ for beneficial use or storage in a geologic storage formation.

CAP is illustrated in [Figure 9](#).



NOTE See Reference [16].

Figure 9 — Simplified CAP process flow diagram

Details on the unit operations, including Flue Gas Conditioning, Regeneration, Appendix Stripper, CO₂ Dehydration and Compression and Refrigeration Systems should be referred to published information.[16]

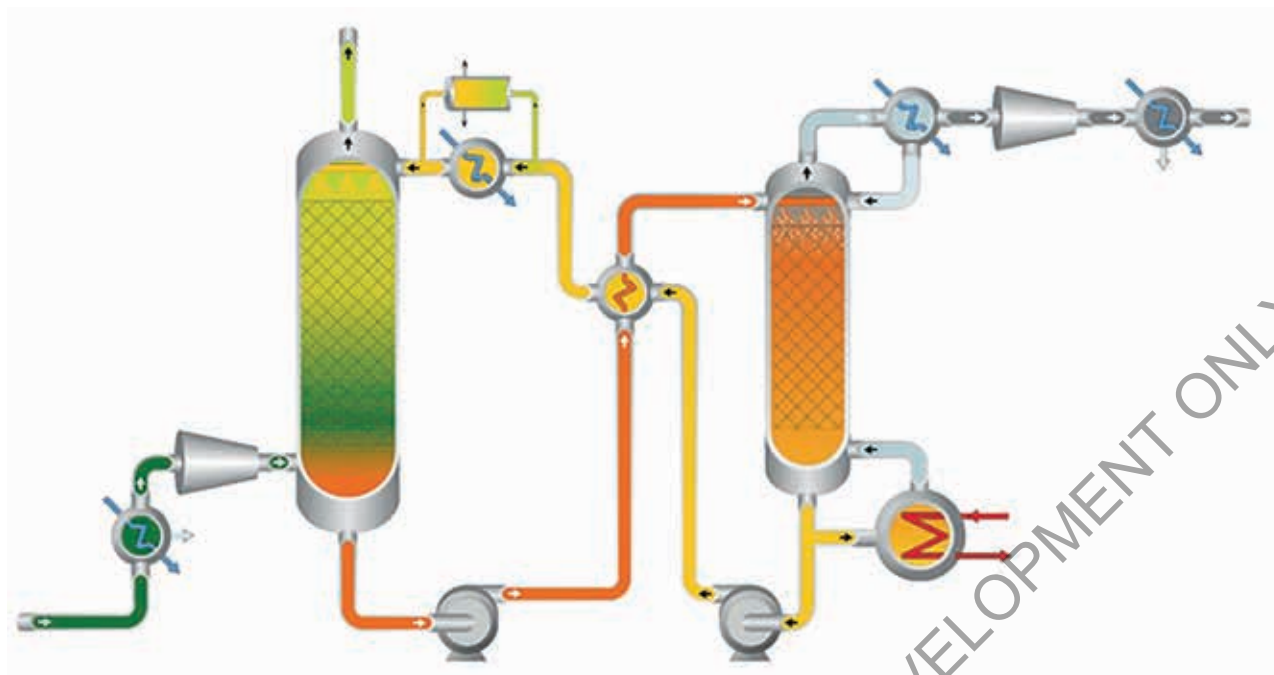
7.2.3 Amino acid salts (AAS) process (C)

The AAS process uses the aqueous solution of amino acid salts as a solvent. Figure 10 shows the flow chart for PostCap²⁾ of Siemens as an example. The equipment configuration is similar to that of a standard amine process.

As the chosen solvent has a very low vapour pressure, it is anticipated that it will cause less emissions from the absorber as the amine system does. In addition, amino acid salts are less susceptible to degradation by oxygen and heat and therefore will have less losses of solvent than the standard amine (MEA) process.[48]

Within the process deposits and solids could theoretically form through precipitation. This is addressed by respective design features and margins. No precipitation was reported during pilot plant operation.[17]

2) PostCap is given for the convenience of users of this document and does not constitute an endorsement by ISO of this process.



NOTE See Reference [48].

Figure 10 — Siemens PostCap AAS process

7.3 Carbon dioxide streams, flue gas streams and emissions, process and waste products

7.3.1 Flue Gas streams

7.3.1.1 PCC plant with coal-fired boiler and gas-fired combined cycle gas turbine (GTCC) with Heat Recovery Steam Generators (HRSG)

The composition of flue gas that is to be introduced into a PCC plant to capture CO₂ is largely a function of the fuel being combusted to generate electricity. In the coal-fired application shown in Figure 11, a Selective Catalytic Reaction (SCR) removes NO_x, Electrostatic Precipitator (ESP) removes particulates, and a flue gas desulfurization (FGD) removes SO₂.

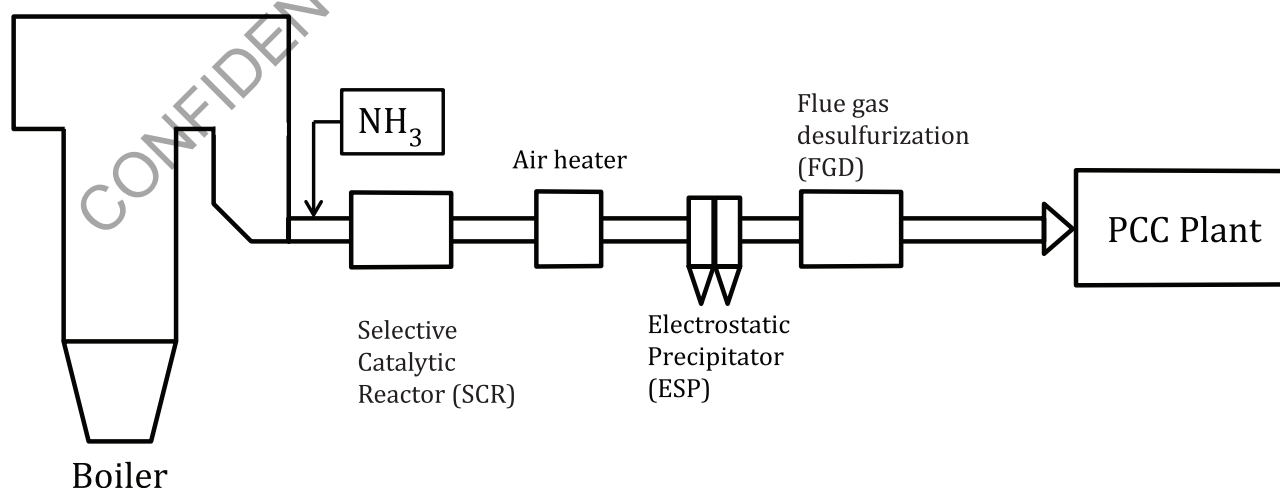


Figure 11 — Gas phase configuration of PCC plant for the coal-fired power plant

In the natural gas-fired application shown in [Figure 12](#), catalytic beds promote the oxidation of CO into CO₂ and NO_x into N₂ and H₂O. Sulfur compounds are not present in natural gas and as a consequence are not generally found in the flue gas.

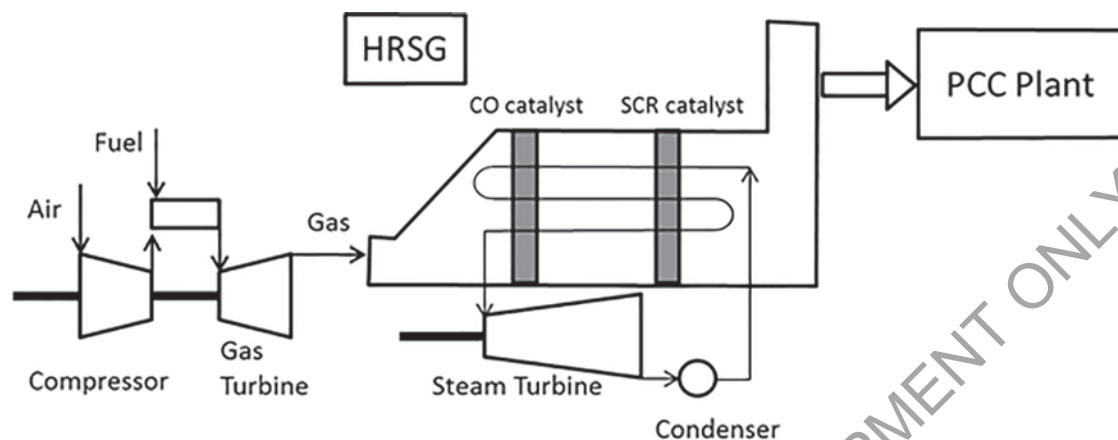


Figure 12 — Gas phase configuration of PCC plant for GTCC with HRSG

As the combustion type steam generation plant, the once-through steam generators (OTSG) for *in situ* oil sands production is an important and growing emissions source in the oil and gas industry and the fastest growing source of emissions in Canada. OTSG is very similar to HRSG fed by the hot combustion gas from the furnace or the gas turbine except for the steam generation section where typically the primary stage evaporates the feed water to an intermediate steam quality and the secondary stage completes the evaporation to a required level for injection into the ground without recycle of the generated steam as the feed water after utilization of its energy. Regarding CO₂ capture from the flue gas, the same concept mentioned above can be applied to OTSG.

7.3.1.2 Input capture plant

“Flue gas streams” in this context refers to the flue gases that occur as a result of the combustion of fossil fuels and that are emitted from such sources as boilers and gas turbines at thermal power plants and HRSGs at GTCC plants.

Currently specific to plants, FGD, CO/NO_x removal equipment and dust collecting equipment are installed to remove impurities (pollutant) pursuant to the relevant emissions regulations and the flue gases downstream of these purification systems are to be the subject gas streams within this Technical Report.

The properties (composition, temperature and impurities) of flue gas supplied to PCC plant varies significantly depending on the type of fuel used, the power plant type and the its system configuration. Generally further abatement of the pollutants, rather than the emission requirement at the conventional stack outlet, is favourable to ensure conditions which allow an efficient and cost-effective CO₂ capture through simplification of the flue gas pre-treatment part or the countermeasures inside the PCC plant, depending on the applied technology.

Particularly in the case of coal, the composition of impurities varies greatly according to its grade and mining location, and this may result in severe impacts related to the flue gas composition depending on the above purification systems performance.

The characteristics of flue gases from power plants are manifested in the flow rate, temperature, gas pressure, and composition (e.g. N₂, O₂, CO₂, H₂O, NO_x, SO_x, NH₃, mercury, soot, ash). There could be an obvious impact on the end-of-pipe CO₂ capture process design, even when the PCC plant is not installed to treat 100 % of the flue gas.

It is very important to clarify the flue gas properties fed to PCC plant in terms of a proper comparative evaluation of technology as explained in [7.4](#) and achievement of high reliability as explained in [7.6](#), as well as fulfillment of emission regulation and waste management explained in [7.3.3](#) and [7.3.6](#).

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Flue gas conditions are a function of fuel type, combustion conditions and pre-existing environmental technologies.

The following are examples of flue gas compositions when natural gas or coal is used as fuel.

Example 1 — Natural gas-fired ([B.1](#))

SINTEF, Emission Compound Toxicity Protocol, P152

Pressure: 1,01 Bar, Temperature: 20 °C to 45 °C (after flue gas quencher), Composition (N₂ 76 mol%, O₂ 13,8 mol%, CO₂ 3,4 mol%, H₂O 6,8 mol%, NO_x 3 ppmv, NH₃ 2 ppmv)

Example 2 — Coal-fired ([B.2](#))

CSIRO, process modelling for post combustion capture plant, P91

Temperature: 104,5 °C, Composition (N₂ 75,8 vol%, O₂ 6,3 vol%, CO₂ 10,1 vol%, H₂O 7,8 vol%, NO_x to 150 ppmv, SO_x to 200 ppmv, HCl ppmv)

The important parameters summarized below, which will impact the plant design as explained in the above, should be clarified and will be surveyed in the next step for indication of the typical ranges (minimum to maximum) respective to applied fuel type (coal, gas and LFG) so as to clarify the characteristics depending on the fuel type, including the effect of both combustion condition and existing environmental equipment.

- Flue gas flow rate
- Flue gas temperature
- Flue gas pressure
- Flue gas composition:
 - O₂
 - CO₂
 - H₂O
 - NO_x
 - SO_x
 - NH₃
 - CO
 - mist
 - dust

7.3.1.3 Output capture plant (treated gas)

There are treated flue gases which are discharged to the atmosphere from the PCC plant after impurities have been removed by purification equipment and the amount of CO₂ has been captured.

As treated flue gases are released into the atmosphere, there is a need to characterize the discharge in order to meet regulatory and permitting requirements that specify the concentrations of pollutants, including additional absorbent derived substances, to acceptable levels.

Although identified parameters that could impact the compositions of the treated gas should be surveyed if needed in the next step, according to the variety of the inlet flue gas to PCC plant as shown in [7.3.1.2](#), the properties of flue gases emitted from power plants are varying, as are the properties of treated flue gases. The concentration of CO₂ normally gets around 1 % in case of boiler flue gas application, however, this value varies depending on the capture rate of CO₂ from the flue gases and

both SO_x and the solvent get in the order of ppm as shown in the Examples below. SO₂ is easy to be captured, while NO is not possible. Studies are underway to lower the concentrations of absorbent (amines), which is generated in PCC plant, in order to reduce the impact of their emissions.^[26]

The parameters listed below, which characterize PCC plant output in the emission sides and have the obvious or possible impact on the plant design as explained in the above, should be clarified in terms of the requirement, if any, and should be surveyed in the next step for indication of the typical range respective to applied fuel type (coal, gas and LFO) so as to clarify the influence of the fuel type including the influence of both combustion condition and existing environmental equipment.

- Outlet gas flow rate
- Outlet gas temperature
- Outlet gas pressure
- Outlet gas composition:
 - O₂
 - CO₂
 - H₂O
 - NO_x
 - SO_x
 - NH₃
 - CO
 - mist
 - dust
 - VOC
 - absorbent
 - absorbent degradation product
 - organic compound

Trace components contained in the gases are discussed in [7.5](#).

The following are examples of flue gas compositions when natural gas or coal is used as fuel.

Example 1 — Natural Gas-Fired ([B.1](#))

SINTEF, Emission Compound Toxicity Protocol, P152

Pressure: 1,01 Bar, Temperature: 20 °C to 45 °C, Composition (N₂ 81,5 mol%, O₂ 13,8 mol%, CO₂ 0,6 mol%, H₂O 3 mol%, NO_x 2 ppmv to 20 ppmv, NH₃ <50 ppmv, amine <5 ppmv)

Example 2 — Coal-fired ([B.2](#))

CSIRO, process modelling for post combustion capture plant, P91

Temperature: 27,65 °C, Composition (N₂ 89,2 vol%, O₂ 6,8 vol%, CO₂ 0,9 vol%, H₂O 3,2 vol%, NO_x approx. 150 ppmv, SO_x <5 ppmv, HCl <5 ppmv, MEA <5 ppmv)

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7.3.2 Composition of carbon dioxide streams

“Carbon dioxide streams” refer to the captured (purified) CO₂ gases leaving the regenerator and then compressing the remaining gases. The characteristics of carbon dioxide streams include flow rate, temperature, gas pressure, and composition (e.g. N₂, O₂, CO₂, H₂O, NO_x, SO_x, hydrocarbons, solvent components).

The specifications for the captured (purified) CO₂ are different depending on whether high-pressure pipelines or shipping, which requires cooling and liquefaction, is used as the mode of transportation. Therefore, the pressure and temperature follow the specifications set by individual plants. Variation in compression discharge (i.e. battery limits) pressure should meet pipeline requirements. This could be a changing condition depending upon the pipeline system requirements over time. Design consideration for pressure variation is needed.

To prevent equipment damage due to the corrosion of pipes and the solidification of moisture during cooling, the concentrations of water, oxygen, SO_x and NO_x are strictly controlled. To also ensure proper transportation and storage of the CO₂, it is necessary to consider the requirements in that respect. Currently, no universally agreed figures of the maximum value of water and oxygen exist and then the requirements also set by individual plants have to be followed utilizing the CO₂ purification process described below in the outline, if necessary. CO₂ specifications are provided by the pipeline operator.

Oxygen removal is accomplished by catalytic oxidation and is based on the reaction of hydrogen with oxygen with excess hydrogen to the downstream. The process and the respective equipment can be scaled up.

A number of suitable technologies for CO₂ dehydration already exist. Glycol-based systems utilizing triethylene glycol (TEG) and solid adsorption systems using the molecular sieve are the most likely technologies for implementation. The process and respective equipment can be scaled up.

There are several liquid agents available for use as a dehydration medium from a variety of different vendors, TEG is well known in the continuous process. In this process, lean TEG fed to the contactor absorbs the moisture in the raw CO₂ gas at the surface of the packing inside. Rich TEG with absorbed water is removed from the chimney tray of the contactor to be routed to the regeneration package for purification by the addition of heat and the stripping agent, if required, to produce lean TEG, which achieves the required purity for the dehydration performance and recycles to the contactor after cooling. Considerations in the process as minimum are

- a) heat integration between the rich and the lean TEG for heat economy,
- b) prevention of TEG entrainment as mist with dried CO₂ stream CO₂ gas velocity control with demister device in the contactor, and
- c) prevention of TEG loss by controlling the operation temperature in the regeneration package.

Relatively small CAPEX/OPEX generally and the robustness to impurities in dehydrate gases are its merits compared with the solid sorbents. However trace TEG enters into the CO₂ stream.

Substances that are well suited as solid adsorption agents are inorganic silica gel, activated alumina and the molecular sieves, a material with very small holes of precise and uniform size. At least two fixed bed adsorbers, which are alternatively loaded or regenerated, are required. Solid adsorption systems can be used if significantly lower moisture contents are required.

The normal compression process, such as compressor inter-stage cooling with knockout vessels, reduces the gas equilibrium moisture content and could offload the dehydration unit, resulting in smaller dehydration systems. The CO₂ purification process will be operated at the pressure range within the multi-stage CO₂ compressor system and located between adequate steps of it as an economic optimization. Using multiple dehydration techniques in series of the system above is possible.

Invariably, the contact with the package vendors or the media vendors is required for the access to the cost and operation information with clarification of the required specification and the compositions of

the CO₂ stream including impurities. Details on the characteristics of the various drying processes and their integration into the PCC system should be referred to published information.^[26]

The important parameters summarized below, which characterize the CO₂ stream of PCC plant as explained in the above and have the obvious or possible impact on the plant design, should be clarified in terms of its requirement and should be surveyed in the next step in the typical range respective to applied fuel type (coal, gas and LFO) so as to understand its properties according to the variety of its requirement.

- CO₂ flow rate
- CO₂ temperature
- CO₂ pressure
- CO₂ composition:
 - CO₂
 - O₂
 - H₂O
 - NO_x
 - SO_x
 - NH₃
 - VOC
 - absorbent
 - absorbent degradation product
 - organic compound

This list only applies to PCC from combustion sources.

It is very important to highlight the item other-than-normal operation and the related consequences.

The following are examples of CO₂ compositions.

Example 1 — Coal-fired (B.2)

CSIRO, process modelling for post combustion capture plant, P91

Temperature: 23,2 °C, Composition (N₂ 0 vol%, O₂ 0 vol%, CO₂ 98,2 vol%, H₂O 1,8 vol%, NO_x approx. 7,4 ppmv, SO_x <5 ppmv, HCl <5 ppmv, MEA <5 ppmv)

Example 2 — Coal-fired (B.3)

GHGT-11, Project Status and Research Plans of 500 TPD CO₂ capture and sequestration Demonstration at Alabama Power's Plant Barry, P.6344

Composition (N₂ 210 ppm, O₂ + Ar 38 ppm, CO₂ >99,9 vol%)

Example 3 — Coal-fired (B.4)

GCCSI, ROAD CSS Non Confidential Feed Report, P34

Composition (N₂ 1 mol%, CO₂ 99,9 mol%, H₂O <30 ppmv)

Example 4 — Coal-fired^[3]

IPCC, Special Report on Carbon Dioxide Capture and Storage (2005), P141

For coal-fired plants (SO_x <0,01 vol%, NO <0,01 vol%, N₂ + Ar + O₂ 0,01 vol%)

For gas-fired plants (SO_x <0,01 vol%, NO <0,01 vol%, N₂ + Ar + O₂ 0,01 vol%)

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7.3.3 Solvent streams, reclaiming waste products

“Waste products” refer to those substances emitted from a CO₂ capture facility other than the aforementioned emissions described under 7.3.1.2 and CO₂ streams under 7.3.2. In the following subclauses, the term “solid waste” describes solid, semi-solid, liquids or contained gaseous material. [30] Primary examples include waste products generated when absorbents, adsorbents, or membranes to be used for CO₂ capture are recycled and cleaned, and used absorbents, adsorbents, and membranes, and waste detergent discharged from equipment cleaning.

7.3.3.1 Waste products (process effluent)

CO₂ capture technologies can be differentiated by the types of effluents they generate. For amine-based technologies, effluents are generated during the treatment of heat stable salts. For ammonia-based technologies, residual ammonia in the treated flue gas is neutralized with sulfuric acid to form ammonium sulfate, which can be utilized as a fertilizer, depending on the impurities concentration.

The function and necessity of a reclaimer in chemical absorption processes is described in 7.2.1.

Absorbents degrade with the elapse of operating time and need to be regenerated on a periodic basis. During this process, a portion of the absorbent, with impurities and degraded substances, is separated and disposed of as reclaimer waste according to federal, state and local regulatory requirements.

One of the following waste treatment methods is selected based on the circumstances at the plant:

- a) off-site disposal contracted out to a waste disposal contractor;
- b) on-site incineration using an incinerator;
- c) on-site crystallization to obtain solid ammonium sulfate which can be sold as fertilizer (for ammonia-based process);
- d) off-site shipment of ammonium sulfate liquid as feed for a fertilizer process (for ammonia-based process).

In general, a chemical analysis is performed on waste product (process effluents) to ensure that their range of characterization is consistent with the specification. While the characterization of waste product (process effluents) depends on regulation and recipient requirements, the following basic information is required:

- The physical properties and chemical composition of the waste.
- Waste category (product quality specification) or complete analysis data needed for legal classification of waste, hazardous or non-hazardous. For example, if it has any of the four characteristics (ignitable, corrosive, reactive, toxic) in 40 CFR Part 261, it is classified as a hazardous waste and if a US RCRA listed solvent is used in the process, the waste solvent would be a listed hazardous waste in US. If it displays one or more of the characteristics of hazardous properties (explosive, oxidizes, ignitable, irritant, harmful, toxic, carcinogenic, corrosive, infectious and mutagenic) listed in the Directive 2008/98/EC, Annex III, 12 December 2008, it is classified as hazardous waste in EU. [30]
- Total annual production.
- Selected method of transport for the selected waste disposal method.
- Safety Data Sheets (formerly known as “Material Safety Data Sheet [MSDS]”) of the component, if it is available.

In the amine-based technologies, since the waste has typically the heating values within range of those of lignite coals, firing it in the cement kiln or in the on-site pulverized coal power plant is a potential disposal option. However, the addition of the waste to the cement kiln would require additional testing to show that the kiln emissions would still comply with the applicable emission limits while using the waste as fuel. A pulverized coal power plant co-firing the waste would be subject to Commercial

and Industrial Solid Waste Incinerator regulation (CISWI), whereas when the waste is considered a hazardous waste, then co-firing this material would be regulated as a hazardous waste combustor under the hazardous waste regulations of 40 CFR Parts 260 through 270 or state equivalent (whichever is more stringent) in the US. In EU co-firing any amount of reclaimer waste in the boiler furnace triggers the Waste Incinerator Directive (WID) without minimum threshold of the co-fired waste amount and is classified as waste incineration.^[30]

For amine-based technologies, thermal reclaiming is the most robust solvent reclaiming method and the ion exchange solvent reclaiming or the electrodialysis solvent reclaiming can be applicable depending on PCC technology. In the thermal reclaiming,^[30] chemicals like alkalines such as NaOH may be used to support the regeneration of the solvent, which should be handled with care, and some sodium will be found in the waste product in this case. Residues from the reclaiming process are mostly harmless sulfates produced by neutralization (e.g. Na₂SO₄); however, in some cases, toxic degradation products such as nitrosamines and nitramines described in 7.5.3.2 may occur, which should be handled with caution.^[47]

While amine and ammonia processes generally evaporate the solvent by use of steam utilizing the generated vapour for stripping of CO₂ in the stripper (desorber or regenerator) and disposing of the remaining components, the AAS process uses crystallization to separate the NO_x and SO_x from the solvent.

In these applications, solid waste management will become more important for the large-scale CCS plant. Therefore it is favourable to list up the outline of the composition and properties of the reclaimed waste product in the typical range. However, such information is very difficult to gather in the public domain.

Other waste products, such as the filter elements of the cartridge filter or the activated carbons beds in the absorbent line, which need man-hours for replacement, will need to be considered. In the event where the dust content in the flue gas going into the CO₂ absorber is relatively high, like coal-fired flue gas, an automatic filter systems may be necessary. The treatment method should be selected by identifying the composition and amount of waste.

7.3.3.2 Solvent streams

The solvent is pumped around in a loop between the absorber and the desorber. In principle, this is a closed loop, but it is not contained in a complete closed system. Solvent droplets and/or aerosols could leave the system at the absorber to the atmosphere or at the desorber to the CO₂ compressor, depending on the process and the demister performance, and have to be considered to minimize emissions and the need for the solvent refill.

Waste generated (process effluent) varies from one CO₂ capture technology to another.

The following are examples of the composition of liquid waste generated when amine absorbent is treated for regeneration.

Example 1 — (B.5)

CSIRO, process modelling for amine-based post combustion capture plant, P94

- a) Reclaimer discharge (Sample A)
SO₄ 4,8 %, NH₃ 1 700 ppmw, NO₃ 5 300 ppmw, absorbent content 46 %, pH 11,0
- b) Reclaimer discharge (Sample B)
SO₄ 15,5 %, NH₃ 1 100 ppmw, NO₃ 7 000 ppmw, absorbent content 33 %, pH 10,0

7.3.4 Waste (process) water streams

7.3.4.1 Waste (process) water sources

Water is generally produced when flue gas is cooled. Depending on upstream flue gas treatment, the water collected could be used as make-up water for cooling tower and other use. There are different waste water sources to be found in a PCC plant, water streams that have to be counted as separate

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streams, which could produce waste water to be discharged out of process as a result of condensation and separation occurring at several process steps and related equipment. These include:

- flue gas cooling;

The flue gas cooler generates flue gas condensate that is affected by the composition of flue gas.

- CO₂ dehydration;
- reclaiming;

Depending on the PCC technology, the waste water as hazardous waste water resulting from the absorption/desorption process may contain traces of Volatile Organic Compounds (VOC) and has to be treated accordingly. Treatment of this amount of water may be necessary.

- others.

Condensation of water occurs also in other parts of the process but the resulting stream is mixed into the solvent stream and therefore not seen as a separate stream to discharge out of the process.

7.3.4.2 Properties of waste (process) water

Waste (process) water treatment should comply with the local waste water effluent regulations and standards of the considered country and region. Characterization of each process water source is the necessary first step in the permitting process.

7.3.5 Emission determination and calculation

7.3.5.1 Emissions into the atmosphere

7.3.5.1.1 Emission release

The following ways of emission release are possible:

- Directly releasing the emissions into the atmosphere from PCC plant (top of the CO₂ absorber). Reheating to avoid immediate condensation is an option.
- Releasing the emissions using an existing stack, when the CO₂ absorber height is not high enough to clear the environmental quality standards in the flue gas temperature and the ground level concentration. In this case, the stack material and the mixing effect with the untreated gas should be checked due to the change in the treated gas properties.

These emissions could include a reuniting of captured CO₂ with the flue gas stream or there could be a separate stack for CO₂ product discharge.

7.3.5.1.2 Concentrations of emission components

Additional equipment for flue gas treatment to ensure compliance with the emission regulations, e.g. reduction of NO_x or SO_x content or dust in the flue gas, is generally considered as part of the power plant/industrial process. Any treatment of the benchmark flue gas that is required prior to introduction of the flue gas in the PCC facility should be included in the scope of the PCC technology provider. In special cases, e.g. revamp of existing plants, it may also be part of the PCC plant. In the PCC process, CO₂ is abated through the CO₂ capture process after the flue gas from the boiler/process and is treated by the aforementioned equipment.

For a GTCC power plant, there is also treatment with NO_x removal equipment and occasionally CO removal equipment. Both are catalyst systems not adding secondary pollutants to the flue gas except for NH₃ depending on the process used.

As a result, the evaluation method of conventional emission in case of PCC plant addition is necessary, taking into account the following positive PCC plant performance on the following flue gas contaminants:

- NO_x , SO_2 , PM removal effect;
- NO_2 is partly absorbed but NO is not absorbed (separate measurement to identify NO and NO_2 may be necessary); SO_2 , SO_3 absorbed;
- PM removal effect in flue gas cooler;
- NH_3 in process ([7.2.1](#), [7.2.2](#), [7.2.3](#)) removal effect;
- reduction of CO_2 flow rate according to the absorption rate as defined in [7.4.2](#);
- concentrations to be measured as CCS in and CCS out in g/GJ and as CCS outlet, the mass flow leaving the absorber should be evaluated.

Additional emission such as amine/amine degradation products (aldehyde, ammonia, etc.) are discussed in [7.5](#).

7.3.5.1.3 Emission regulations

In cases where there are no clearly defined emission regulations for PM, SO_x and NO_x leaving a CO_2 capture plant, it is suggested to express pollutants in g/GJ (fuel input), due to additional fuel fired. A requirement may be set as the mass of pollutants in total is not higher than that of the entering flue gas.

In addition, other substances related to CO_2 capture process is regulated by the existing regulations, such as VOC and ammonia, depending on the region and the technology.

In order to obtain an operating license for a PCC plant (as is generally required for such big plants), an EIA permit is required. General requirements following IFC General EHS guidelines as a minimum requirement should be considered and checked with local EIA regulations.[\[73\]](#)

7.3.5.1.4 Methods of calculating the concentrations of impurities

There have been methods developed for the conventional plants applicable to the measurements of the amounts and compositions of the flue gas, SO_x , NO_x and PM. These need to be adapted for the changed flue gas streams (O_2 -ref. content, etc.).

Issues may be encountered when measuring trace or impurity components that are unique to the PCC system. Research is currently underway to develop simple and accurate measurement methods for such substances that are present as both gas and mist phase.[\[33\]](#)[\[36\]](#)

7.3.6 Process by-products

Other than pressurized CO_2 , which may improve the economy depending on the process, there can also be the following by-products produced in the specific process.

Examples of economically interesting by-products of some capture processes are $(\text{NH}_4)_2\text{SO}_4$ and K_2SO_4 .

7.4 Evaluation procedure for capture performance

CO_2 capture from flue gases emitted by fossil fuel power stations, which are large stationary sources, is an effective means of reducing Greenhouse Gases (GHG). However, its economic viability is yet to be established and efforts toward its market application are currently underway. It is noted that mechanisms should be established to facilitate knowledge sharing from early CCS projects.

Based on this philosophy, among a number of project-specific Front End Engineering Design (FEED) of large-scale CO_2 capture and compression plant completed in recent years, only a few are in the public domain, including Longannet project of ScottishPower Ltd.,[\[31\]](#) Kingsnorth project of E.ON UK[\[31\]](#) and the Rotterdam Capture and Storage Demonstration Project (ROAD).[\[32\]](#) For FEED series

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overall capital cost estimation is supported by detailed engineering and provides sufficient accuracy to permit an informed business decision. Caution needs to be exercised in applying these public studies for a specific location and project. Considerable variability can be found in available plot space, utility capacity, current ducting layout and operating objectives.

On the other hand, new regulations, such as Directive 2009/31/EC on the geological storage of carbon dioxide, requires businesses of new large-scale coal-fired power plants (nominal electrical output of 300 MW or more) to conduct studies into presence or absence of appropriate storage site, technical feasibility and cost of transport equipment, technical feasibility and value of additional CO₂ capture facility (retrofit). Moreover, this philosophy also supports compliance with the above requirement in order to build a new large-scale coal-fired power plant, since, for supercritical pulverized fuel (PF) plant, the most developed capture retrofit options are post-combustion amine capture and oxyfuel combustion.^[33]

Reflecting this background, developing a standard for the performance evaluation method of CO₂ capture technologies could help to achieve the following goals of CO₂ capture technologies:

- facilitating an objective evaluation of the current state of progress for better understanding and sharing of public knowledge;
- contributing to fair competition without hampering technological advancement;
- promoting the development of widespread application.

7.4.1 Clarification of the evaluation basis

In order to carry out a proper comparative evaluation, the evaluation basis and the definition of major performance values and the economic indexes should be clarified, as the reported figures could be site- or technology-specific and should therefore be normalized. In addition, the estimating methodology should be identified and applied uniformly across each plant design.

It is important to establish a common set of start and end points. To start, the flue gas properties such as flow rate, temperature, pressure and the composition (such as H₂O, CO₂, O₂, SO_x, NO_x, HCl and dust) should be established. Quality of the treated flue gas stream and the CO₂ product stream should be defined. Finally, a common list of utilities such as steam, steam condensate, cooling water, power, pressurized air, chemicals and industrial gases should be established. Modifying the basis set of utilities would need to be accommodated within the scope of the CO₂ capture system.

In addition, the following performance parameters affect the economic index and should be clarified before evaluation.

7.4.2 Basic performance

7.4.2.1 CO₂ capture efficiency and total mass of CO₂ captured

CO₂ capture efficiency (η_{CO_2}) is defined as follows:

$$\eta_{\text{CO}_2} = (f_{\text{CO}_{2\text{in}}} - f_{\text{CO}_{2\text{out}}}) / f_{\text{CO}_{2\text{in}}} \times 100 \quad (1)$$

where

$f_{\text{CO}_{2\text{in, out}}}$ is the mass flow rate of CO₂ at CO₂ capture plant inlet and outlet (treated flue gas emission side) [in Nm³/h].

$$f_{\text{CO}_{2\text{in}}} = F_{\text{in}} \times \text{CO}_{2\text{in}} / 100 \text{ [Nm}^3\text{/h]} \quad (2)$$

$$f_{\text{CO}_{2\text{out}}} = F_{\text{in}} \times (1 - \text{CO}_{2\text{in}} / 100) / (1 - \text{CO}_{2\text{out}} / 100) - F \times (1 - \text{CO}_{2\text{in}} / 100) \text{ [Nm}^3\text{/h]} \quad (3)$$

NOTE Since the outlet gas flow rate changes according to the CO₂ removal rate and the inlet gas flow rate, which is always constant, is based on and $f_{CO_{2out}} = F_{out} \times CO_{2out}$ is not applied.

where

$F_{in, out}$	is the flue gas flow rate at CO ₂ capture plant inlet and outlet (treated flue gas emission side) [Nm ³ /h-dry];
CO_{2in}	is the CO ₂ concentration in the flue gas at CO ₂ capture plant inlet [vol%-dry];
CO_{2out}	is the CO ₂ concentration in the flue gas at CO ₂ capture plant outlet (treated flue gas emission side) [vol%-dry].

Total mass of CO₂ captured is defined as follows:

- The total mass of CO₂ captured is measured by the flow meter installed in the product CO₂ line (before CO₂ compression), corrected by the operating condition: (W_A).

In the operational data evaluation case, it is also recommended to check the following calculations:

- Total mass of CO₂ captured calculated from the absorbent side by the measurement of the dissolved CO₂ concentration (g/L) and the flow rate of absorption solvent (both the lean and rich solution): (W_B);
- Total mass of CO₂ captured calculated from the flue gas side by the balance calculations from the gas side in the above [Formula \(2\)](#) and [Formula \(3\)](#): (W_C).

If the difference among the value calculated from (W_A), (W_B) and (W_C) is within the acceptable level, the CO₂ balance is maintained correctly. Online analyzers have also been developed for the analysis of absorption solvent and it is possible to quickly perform the operation management.[\[34\]](#)

7.4.2.2 Properties of the captured CO₂ at CO₂ compression system outlet

7.4.2.2.1 CO₂ purity

In the chemical absorption processes, a CO₂ concentration (on a dry volumetric basis) of 99 % or more can be achieved.[\[35\]](#)

7.4.2.2.2 Concentrations of CO₂ impurities

The captured CO₂ contains moisture, oxygen and nitrogen as a by-product of the absorption/desorption process. Quality of CO₂ and content of other elements (H₂O, N₂, O₂) has to be defined with regards to transport and storage/usage requirements. Conditions required for the further processing of the CO₂ have to be given by the organization responsible for transport and storage. This includes CO₂ quality inclusive of allowable pressure content of other elements, e.g. H₂O, N₂ and O₂. If the requirements concerning the moisture and the oxygen concentrations from the transportation side and beyond are too stringent for the specifications to the CO₂ capture and compression systems, it may be necessary to install a dehydrator (moisture removal system) and/or an oxygen removal system.

7.4.2.2.3 CO₂ compressor system outlet port pressure

Coordination with the CO₂ transportation side based on CO₂ transportation mode and the actual specifications of the transportation is needed. Interface pressure and temperature of CO₂ capture equipment with CO₂ compression system is recommended to be defined in the specifications of the CO₂ compressor along with impacts on the evaluation of the power consumption of the CO₂ compressor.

7.4.2.2.4 Others

Captured CO₂ is the end product of the CO₂ capture and compression process and it is important to have quality control measures in place. CO₂ metering will be required in the system to measure plant

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performance, potentially as a means of demonstrating compliance with the requirement from the transportation and sequestration side and environmental regulations, as a total.

7.4.3 Utility consumption

7.4.3.1 LP (-MP) steam

The required steam for the desorption process is delivered by the power or industrial plant. The way the steam is extracted from water steam cycle depends on the local power plant operating conditions. Majority is LP and MP is required for some cases

The LP (-MP) steam required by the PCC plant can be extracted from the water-steam-cycle in the power plant. This requires modifications in the power plant steam cycle and results in a reduction of the power plant efficiency. In terms of power plant performance alone, it is favourable to lower the conditions of the extracted steam as much as possible.^[32] In the case that the power plant is mature and the modification is restricted, or there is a necessity to avoid any impact of power plant operation, an additional gas- or oil-fired boiler can be installed with the existing open cycle gas turbine being modified with an HRSG to supply LP steam.^[31] The water condensate of the PCC is discharged in the condensate system of the power plant.

7.4.3.2 Power consumption

For rotating machinery like pumps, blowers, compressors, electric motors and/or steam turbines using MP to HP steam can be used as the driver. When the steam turbine drive is selected, the outlet steam is used again as LP steam for PCC plant and its supply source needs to be considered. When an electric motor is used, a power generation penalty as an equivalent to the LP steam consumption in [7.4.3.1](#) may be incurred, depending on its electrical consumption. In any case, the shaft power consumption varies according to the model and efficiency of the compressor applied and the CO₂ product gas interface pressure at CO₂ capture unit outlet before CO₂ compression unit-inlet.

Ammonia systems typically have higher regeneration pressures than generic amine systems as the vapour pressure of the solvent with higher pressure heating steam for the reboilers, provides higher interface pressure of the captured CO₂ at CO₂ capture unit outlet. As a result, the design and number of stages of the compressor can vary significantly. In addition, a higher suction pressure reduces power demand.

Therefore, a separate assessment of the impact to the drive energy consumption needs to be performed for CO₂ capture plant part and CO₂ compression part, respectively.

7.4.3.3 Cooling medium (CW)

In the PCC plant, CW is used at several steps and its required amount depends on the capacity and the efficiency of the process applied. Feed and the return outlet temperatures of CW should be made clear, since it may affect process performance. When once-through water cooling is not viable, evaporative cooling towers or air coolers could be employed. If it is difficult to secure water, an air-cooling fan can be applied. For the chilled ammonia process, a chilled water system is needed to supplement CW to achieve the desired absorption temperatures. This utility is typically supplied by a refrigeration system using anhydrous ammonia as the refrigerant.

In either case, required power consumption used for providing CW or required chilled water should be included in the total power consumption in [7.4.3.2](#).

Waste heat integration using steam cycle condensate as cooling medium in the PCC coolers result in a reduction of the additional cooling duty associated with the PCC operation.

The steam extracted from the steam cycle for solvent regeneration reduces the cooling requirements of the turbine condenser, therefore offsetting some of the increase in cooling utility required by the PCC plant.

7.4.3.4 Demineralized water

In the PCC process, demineralized water is required for dilution of solvent, of the form received from production, to supplement and maintain on specification alkaline solution during operation as required for the process

7.4.3.5 Absorbent/solvent and other chemicals

Different types of chemicals, including absorbents, caustic soda or other alkaline used for desulfurization, sulfuric acid for ammonia neutralization, nitrogen, activated carbon and hydrogen used when necessary to de-oxidize, depending on the requirements of the process deployed have to be considered. Absorbents in particular have a major economic impact due to the large amounts in which they are consumed in the case of a large-scale PCC plant. Therefore, it is necessary to clarify the consumption amount, refill method, transporting method and to develop technologies to minimize the amount of consumption.

7.4.4 Operability (operational requirements)

Since PCC plant requires consequential amounts of LP steam and electricity, it is necessary to operate in collaboration with the hosted power stations and/or utility supply systems in order to achieve efficient operation. The following are the general operational requirements.

7.4.4.1 Load following (ramping speed)

While various scenarios of economical operations are possible, a PCC plant should be able to handle the capacity of the flue gas source (e.g. provided by the thermal power plant) and ideally not impose any restrictions on it. Furthermore the PCC plant should be able to adjust its operating load in accordance with a maximum load ramp up rate required, such as 5 %/min.

7.4.4.2 Partial load operation

The requirements of the flue gas source could make it necessary for PCC plant to operate at partial load and the stable operation at the specified partial load should be satisfied, solving the issues of a lower operating threshold such as a liquid distribution balance within the system. It has to be considered that flue gas composition may differ significantly in partial load operation, it is noted that the CO₂ concentration of the flue gas can change as the unit ramps up and down. In addition the NO_x content in the gas turbines is also known to vary.

7.4.4.3 Availability

The following is a definition of availability in PCC plant, although there are different ways to express it. Since it concentrates on the operational reliability, the periodic maintenance period related to the maintainability could be discussed separately.

$$\text{Availability} = (1 - \text{FOR}) \times 100 \% \quad (4)$$

$$\text{Forced Outage Rate (FOR)} = \frac{\text{FOH}}{\text{Period of Operation Hour (POH)}} \quad (5)$$

where

FOH is the number of hours a PCC plant is unable to treat the flue gas from the hosted power plant due to the inability of PCC plant to operate;

POH is the total period of hours for a PCC plant with calendar date basis, excluding the periodic maintenance period.

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7.4.5 Economic evaluation index

Utility consumption (LP steam and electricity consumption) has a major impact on the economic performance of PCC plant and evaluated in subsequent subclauses.

7.4.5.1 Specific Energy Consumption (SEC) for PCC plant

SEC, which refers to the thermal energy consumption, is defined as:

$$\text{SEC} \left[\frac{\text{GJ}}{\text{tCO}_2} \right] = \frac{\left\{ \left(\text{supplied steam flow} \left[\frac{\text{t}}{\text{h}} \right] \times \text{steam enthalpy} \left[\frac{\text{GJ}}{\text{t}} \right] \right) - \left(\text{recovered steam condensate flow} \left[\frac{\text{t}}{\text{h}} \right] \times \text{condensate enthalpy} \left[\frac{\text{GJ}}{\text{t}} \right] \right) \right\}}{\text{captured CO}_2 \text{ amount} \left[\frac{\text{tCO}_2}{\text{h}} \right]} \quad (6)$$

7.4.5.2 Specific power consumption (SPC) for CO₂ capture and compression

Specific power consumption (SPC) for CO₂ capture and compression is defined as:

$$\text{SPC} [\text{kWh/tCO}_2] = (\text{power consumption of PCC plant} [\text{kW}]) / \text{captured CO}_2 \text{ amount} [\text{tCO}_2/\text{h}] \quad (7)$$

NOTE Power consumption of PCC plant includes CO₂ compression and related utility facilities.

7.4.5.3 Electricity output penalty (EOP)

Electricity output penalty (EOP), as defined below, is the unit output penalty by PCC technologies independent of fuel composition.^[39]

$$\text{EOP} = \text{Efficiency penalty} / \text{fuel specific emissions} \quad (8)$$

where

- EOP is the total net loss in plant output due to PCC plant, as indicated in [Formula \(9\)](#), in kWh/tCO₂;
- Efficiency penalty is calculated based on the extracted steam information, the heat balance of the steam turbine and the auxiliary power consumption required for PCC plant, in kWh/kWh_{th};
- Fuel specific emissions are calculated based only on the fuel information, as shown in Reference [\[40\]](#), Annex B, in tCO₂/kWh_{th}.

$$\text{EOP} = \frac{1\,000 \times [\text{loss of gross power output (MW)} + \text{PCC plant power consumption (MW)}]}{\text{CO}_2 \text{ captured amount (tCO}_2/\text{h)}} \quad (9)$$

Therefore, loss of steam turbine generator output by the steam extracted from a steam turbine and the unit cost of steam should be assessed using the heat balance data of the steam turbine. In determining the unit cost of the steam for the purpose of conducting economic evaluation, the efficiency and operating restrictions of the power plant need to be considered.^{[41][42]}

The development of high-efficiency super-critical thermal power plant and GTCC plant, with very low levels of pollutants like NO_x, SO_x and PM makes the installation of such capture plants much more sustainable.^[53]

The unit cost of steam based on individual configuration would be needed to calculate the running cost.