

Emissions from CCS technologies and their measurement

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Confidentiality: Confidential

Report's title Emissions from CCS technologies and their measurement		
Customer, contact person, address MMEA Research Program	Order reference	
Project name CCS-studies/WP4.2.2	Project number/Short name 71091	
Author(s) Tuula Kajolinna	Pages 15	
Keywords CCS, emission monitoring	Report identification code VTT-R-04876-13	
Summary <p>This literature study is related to the search of new emission monitoring needs and requirements for carbon capture and storage technologies (CCS). The study is focused on emission monitoring aspects of carbon capture technologies. Emissions to water and soil are excluded from this report as well as the monitoring of CO₂ during transport and storage.</p> <p>This report describes the regulation set in EU, USA, Australia and Canada. Moreover, different CCS technologies and their reported emissions are described.</p> <p>According to reviewed estimations and pilot scale emission studies, variation of emissions to atmosphere from CCS technologies is very wide. Estimations showed that in oxyfuel and pre-combustion processes, the emissions are likely to decrease. However, emissions from post-combustion using amine based technology are estimated to increase and emissions compounds are not well known yet.</p>		
Confidentiality	Confidential	
Espoo 1.7.2013		
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Distribution (customer and VTT) MMEA Research Program		
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1 Introduction

MMEA research program (Measurement, Monitoring and Environmental Assessment) has a subtask in WP4.2.2 for emission monitoring related to carbon capture and storage (CCS) technologies. Additional goal was to evaluate possible lacks in the measuring techniques for new types of emissions.

2 Description

This report is focused on emission monitoring aspects of CCS technologies reported by different institutions and research centres.

3 Limitations

This study focuses on gaseous emissions from carbon capture technologies. Emissions to water and soil are excluded. Also monitoring of CO₂ during transport and storage are excluded.

4 Regulations for monitoring

Regulation section in this report is reported according to CO₂ capture project (2010) which focused on regulations set in EU, US, Australia and Canada. All text is a direct copy from CO₂ capture project (CO₂CaptureProject 2010).

4.1 Overview of requirements

Significant progress has been made during the last few years across the jurisdictions under study towards the development of legal and regulatory frameworks for CCS. However, a number of remaining gaps and challenges remain within the regulatory regimes.

- In the European Union, the CCS Directive establishes a legal framework for regulating CCS. The Directive addresses key legal requirements pertaining to CCS activities, including permitting, monitoring, reporting and verification (MRV) and long-term liability. Member States are required to transpose its provisions into national law by June 2011. However, regulatory interpretation of the Directive is likely to vary across Member States and precise details pertaining to, for example, the transfer of long-term liability and financial security provision, remain unresolved at present.
- In the United States, the ongoing uncertainty regarding federal climate change policy presents the key barrier to CCS deployment. In the absence of CCS specific legislation, various legal issues remain unresolved including the financial responsibility of operators, long-term site stewardship liability and pore-space rights. There is a significant effort underway to close the gaps and complete a CCS regulatory framework that is largely driven at the state level at present.

- In Australia, the regulatory framework for CCS is being developed largely on the basis of the existing oil and gas regime. Legislation is currently in place for CCS undertaken in Commonwealth waters, onshore Victoria, Queensland and South Australia. Legislation is also being developed by New South Wales and Western Australia for onshore CCS. The shelving of Australia's emissions trading scheme presents a significant barrier to short-term deployment of CCS projects whilst a number of regulatory gaps remain including the financing and regulation of common CO₂ transport infrastructure.
- In Canada, the existing regulatory regimes for oil and gas (provincially based) have been used to accommodate existing CCS activities. The one exception is in cases where storage activities are to take place on Federal lands; however this is not anticipated in the near term. The licensing frameworks have not yet been amended to fully accommodate CCS at a provincial level, with the exception of Alberta which is currently undertaking a CCS regulatory review and has recently announced legislation to enable CCS regulations to be completed in 2011. This legislation is scheduled to be passed in the fall 2010 session of parliament. Other provinces including British Columbia and Saskatchewan are expected to develop the appropriate frameworks for CCS activities.

4.2 Accuracy of measurement

Although specific accuracy requirements, units, and quality assurance are not mentioned in the EU CCS Directive and US EPA GHG reporting rule, it is anticipated that monitoring plans would need to specify monitoring accuracy and data quality assessment protocols according to best practice.

None of the authorities within the jurisdictions studied in this report currently specify requirements in relation to the accuracy of measurement of baseline and boundary data. These are likely to be determined on a case by case basis, according to the prescribed CO₂ storage complex characterisation procedures and any sensitivity analysis there under. However, some specific aspects of monitoring and reporting do set down accuracy requirements.

In the EU, the Monitoring and Reporting (M&R) Guidelines under the EU ETS (Emission Trading Scheme) Directive specify uncertainty levels for fugitive emissions from capture and transport, and also for the transfer of CO₂ between different installations across the chain of capture, transport and storage. In these contexts, the M&R Guidelines prescribe the following requirements:

- For capture of CO₂, the overall uncertainty of estimated CO₂ generation at the facility should be within the limits for the specific installation/activity/tier of reporting as prescribed in the EU ETS monitoring and reporting guidelines (Decision 2007/589/EC);
- For transfer of CO₂ from a capture installation to a pipeline installation, $\pm 1.5\%$;
- For fugitive emissions from CO₂ transport networks, a maximum uncertainty of $\pm 7.5\%$ across a CO₂ transport network;

- For transfer of CO₂ from a pipeline installation to a storage installation, $\pm 1.5\%$;
- For leakage of CO₂ from storage complexes, emissions should be measured with a maximum overall uncertainty of $\pm 7.5\%$.

Some aspects of this may be challenging to meet, for example measuring mass flows of CO₂ under high pressure potentially with multi-phase flows to an accuracy of $\pm 1.5\%$ may be challenging. Also, detection limits for CO₂ leakages depend on the technology used.

4.3 Timelines

In the EU, the CCS Directive requires that measurements be made continuously for the following during a site's operational phase:

- Mass of injected CO₂ (volumetric, pressure and temperature at injection wellheads);
- Fugitive emissions of CO₂ at the injection facility;
- Chemical analysis of the injected material; and
- Reservoir temperature and pressure.

For other non-continuous/non-passive techniques, the frequency of application should be proposed by the operator and subject to specific approval by the competent authority. (CO₂CaptureProject 2010)

5 CCS techniques and emissions

Different CCS techniques and their reported emissions are described on this section.

5.1 Techniques

According to Intergovernmental Panel on Climate Change, IPCC, there are four carbon capture processes and systems which are described in Figure 1.

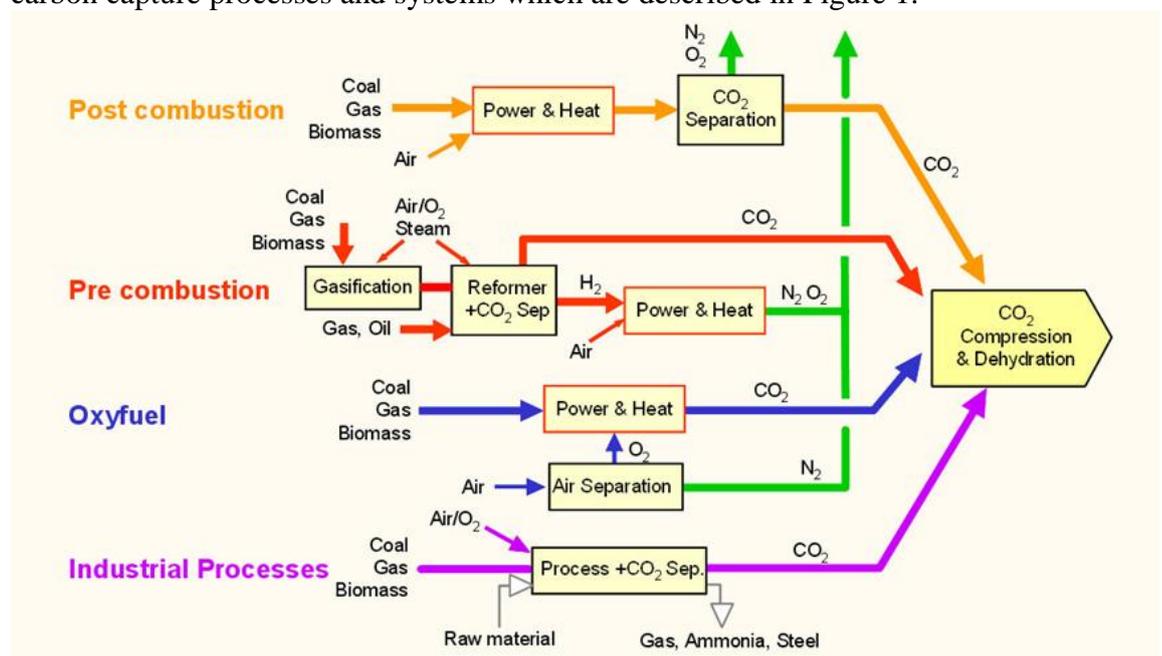


Figure.1. Overview of CO₂ capture processes and systems (IPCC 2005).

5.1.1 Post combustion

The CO₂ is captured from the flue gas following combustion of the fossil fuel. Post-combustion systems separate CO₂ from the flue gases produced by the combustion of the primary fuel in air. These systems normally use a liquid solvent to capture CO₂. Removal efficiency was reported to be in the range of 87–90 %. One advantage of post-combustion systems is that they can be retrofitted to existing coal or gas power plants, industrial facilities, etc. (EEA 2011)

Absorption of CO₂ in Post combustion technology are often performed with amines like

- MEA (2-aminoethanol),
- AMP (2-amino-2-methyl-1-Propanol),
- MDEA (2,2'-(methyylimino)bis-Ethanol) and
- PIPA (Piperazine).

Portions of the amines will degrade, leading to large volumes of degraded amine that must be handled as hazardous waste. (Knudsen et al. 2009)

5.1.2 Pre combustion

Removal of CO₂ from the fossil fuel occurs prior to the combustion process. Pre-combustion systems process the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of carbon monoxide (CO) and H₂ (synthesis gas - 'syngas'). Additional H₂, together with CO₂, is produced by reaction of CO with steam in a second reactor. The resulting mixture of H₂ and CO₂ can then be separated. The technology is expected to develop further over the next 10–20 years and may be at lower cost and increased efficiency compared to post-combustion. (EEA 2011)

5.1.3 Oxyfuel

Oxyfuel combustion systems use pure oxygen, instead of air for combustion of the primary fuel, to produce a flue gas that is mainly water vapour and CO₂. This results in a flue gas with high CO₂ concentrations (more than 80 % by volume). (EEA 2011). CO₂ separation may need post-combustion to achieve quality requirements (CO₂ concentration < 95.5 vol-%) of storage carbon dioxide.

5.1.4 Industrial processes

CO₂ has been captured by industry using various methods since the 1970s to remove CO₂ from gas streams where it is unwanted, or to separate CO₂ as a product gas. Examples of the processes include: purification of the natural gas, production of hydrogen containing synthesis gas for the manufacturing of ammonia, and alcohols and synthesis liquid fuels. Other CO₂-emitting industries are cement, iron and steel production. (EEA 2011)

5.2 Emissions

Emission levels and compounds are reported in few reports and those results are based either on measurements or modelling. Some of the latest results are presented below in the text.

International Energy Agency, IEA publication from year 2012 focused on the changes which are to be expected in the direct emissions, discharges and solid wastes of substances other than CO₂ from within the boundary of power plants fitted with CO₂ capture (IEA 2012). Assessed cases were a) Natural gas combined cycle (NGCC), b) Integrated Gasification Combined Cycle (IGCC), c) Oxycombustion and d) post combustion. The results were presented as relative figures and exact concentrations of the emissions were not presented.

Gaseous emissions were divided into the following categories; Acid gases as CO₂, SO_x (Broken down to SO₂ and SO₃), NO_x (Broken down in to NO and NO₂), HCl, HF and CO. Trace elements were mercury (Hg⁰, Hg²⁺, Hg(p)) and trace metals (As, Cd, Cr, Co, Pb, Mn, Ni, Se, Zn, Cu). Other compounds presented were ammonia, chemical degradation products (NB subject of separate report) and VOC's. Particulates were presented as PM and PM10. Expectations of presented emissions are shown in Figure 2.

Some remarks on emissions from the assessment were:

- SO₂ emissions will be reduced due to demand of sulphur removal from fuel and/or from combusted gas before carbon capture technologies
- NO_x emissions per kWh increase due the higher fuel consumption. The NO₂ (5-10% of NO_x) is assumed to be partly removed by reaction with the amine based solvent. NO_x emissions from the oxyfuel concept are expected to be low, but are highly dependent on the treatment and purification within the concept.
- NH₃ emissions are expected to increase significantly due to post combustion capture, but the uncertainties are large. The increase is caused by the degradation of amine based solvents that may be used in post-combustion capture.
- VOC emissions can increase or decrease due to pre-combustion carbon capture. It is unknown whether and to what extent they are affected by the post and oxyfuel combustion processes.
- Hg emissions are expected to increase due the higher fuel consumption.
- HCl and HF decrease substantially when CO₂ capture is integrated into the power plant. This is due to the acidic nature of these gases and the alkalinity of the solvent.

Changes in emissions and wastes when CCS is applied

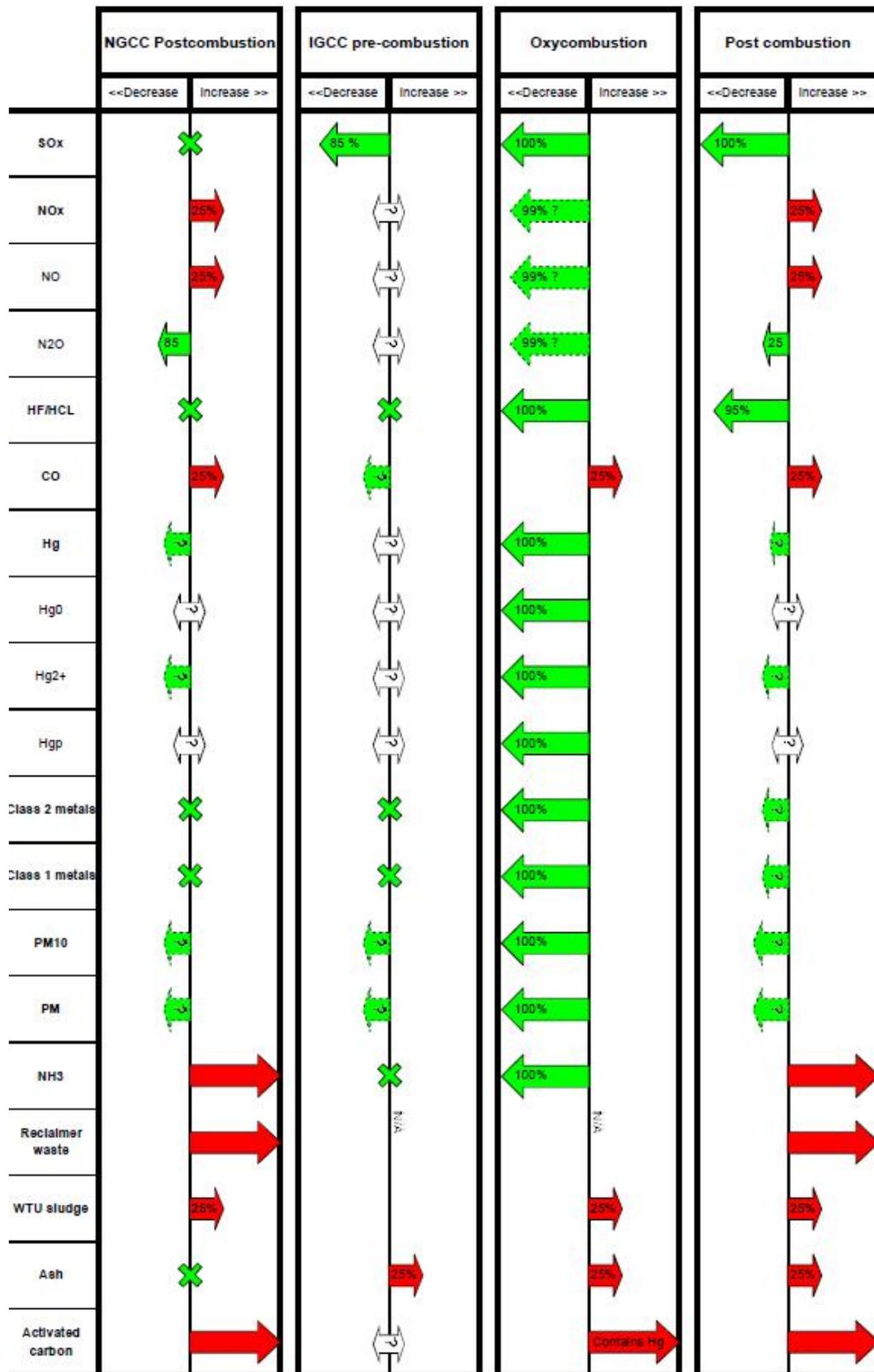


Figure 2. Change expectations of emissions using CCS technologies. IEA 2012.

International Energy Agency, IEA (2012_b) publication focused on the monoethanolamine (MEA) based post combustion CO₂ capture technology. Emissions and their concentration levels were estimated by modelling. It was estimated that

- MEA emissions are between $0.3-0.7 \text{ mg/m}^3_{\text{NTP dry}}$.
- DEA diethanolamine emissions <math>< 0.3 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Ammonia emissions <math>< 1-30 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Formaldehyde <math>< 0.1- < 1 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Acetaldehyde <math>< 0.4 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Methylamine <math>< 0.3 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Acetamide <math>< 1 \text{ mg/m}^3_{\text{NTP dry}}</math>.
- Acetone <math>< 0.5 \text{ mg/m}^3_{\text{NTP dry}}</math>.

According to European Energy Agency, EEA (2011) estimations of direct emissions are:

- SO₂ emissions are generally expected to be very low. For all coal-firing conversion technologies, the sulphur must be removed to avoid solvent degradation in post-combustion processes. For natural gas, the sulphur content is in any case low and thus, SO₂ emissions are expected to be negligible for gas-fired power plants with and without CO₂ capture. In pre-combustion and oxyfuel the required treatment of, respectively, the syngas and flue gas is similarly expected to result in low SO₂ emissions.
- NO_x emissions are believed to be largely unaffected by the (amine-based) capture process in post-combustion technology. Both equal and higher NO_x emissions per kWh are reported when applying pre-combustion CO₂ capture. NO_x emissions from oxyfuel concepts are in general expected to be very low, particularly for gas.
- NH₃ emissions are estimated to significantly increase (by more than a factor of 20) for post-combustion capture technology. This is assumed to be caused by degradation of the amine-based solvent used in the post-combustion capture concept. However, the uncertainty regarding this estimate is considered to be high.
- PM emissions are expected to be removed to ensure a stable capture process in any post-combustion capture process. PM emissions per kWh are expected to increase as a result of the higher fuel consumption. In the literature, however, assumptions vary considerably. It was found out that the application of pre-combustion CO₂ capture may lower PM_{2.5} emissions from an IGCC. For coal-fired oxyfuel concepts, PM emissions are also estimated to be lower per kWh, compared to conventional pulverised coal fired power plants.
- NMVOC emissions. It is largely unknown whether and to what extent NMVOC emissions are affected by the CO₂ capture process in the oxyfuel, pre-combustion and post-combustion concepts.

Knudsen et al. (2009) investigated the theoretical reaction pathways (photo-oxidation schemes) of amines in the gas phase and rate constants of chemical reactions for the four earlier mentioned amines. Amides, nitramines, and nitrosamines predicted to be formed from atmospheric degradation of these amines. Knudsen et al. pointed out also that there is no theoretical way to predict the relative amounts of nitrosamines and nitramines formed in the atmospheric degradation of amines – there is a serious lack of experimental data. It was also

mentioned that amine routes on chemical processes with primary and secondary particles, water droplets (both as clouds and raindrops), and processes related to snow are not assessed.

Pedersen et al. (2010) have assessed degradation and emissions of amine post-combustion techniques. Main reported findings were:

- MEA (monoethanol amine) solvent degrades to NH_3 in presence of NO_x .
- ~0.5 ppmv of stable Nitrosamine NDELA in all samples where existed also NO_x (20-25 ppmv). No NDELA was found in samples without NO_x .
- About 20 % of NO_2 was absorbed into the liquid phase
- MEA slip of 90 ppmv was reported, achieved the mass balance of > 90 %.
- Strong MEA adsorption to sampling lines, needs long sampling times.
- Methyl amine (MA) slip from absorber of 2-4 ppmv was reported.

Mertens et al. 2011 presented the measurement results made in pilot post-combustion plant. Continuous monitoring method using FTIR was compared with manual methods. Results showed ammonia and MEA emissions in concentration level of tens ppms. Results varied depending on the sampling temperature and used method. Results showed that sampling and analysis methods should be standardized in order to have harmonised results.

ZEP (2012) –project has presented six emission compound types from amine post-combustion techniques: solvent amines, ammonia, aldehydes, ketones, nitrosamines and alkylamines. No concentrations were mentioned.

As a summary on emissions, a variation of the results is very wide, and there does not exist detailed assessments to provide an overall picture of the emissions. In the following list, the emissions which are estimated to clearly increase or decrease in CCS processes are presented, including the estimated concentration ranges:

Increases:

- ammonia from < 0.1 ppm up to 40 mg/m^3 ,
- ethanolamines (mono- and di-) from < 0.3 mg/m^3 up to tens of ppms
- aldehydes (form- and acet-) from < 0.5 mg/m^3 up to several ppm
- methylamine and ethylamine from 0.3 mg/m^3 up to several ppms
- Amides, nitramines and nitrosamines, no concentration estimations

Decreases:

- SO_2 from 10 up to < 300 mg/m^3
- NO_x especially in oxyfuel process, up to < 50 mgNO_2/m^3

6 European standard methods

European standard methods for different pollutants are presented in this chapter. In the following tables, the European standard methods for periodic and continuous standard methods with possible measurement techniques are presented (CEN 2013).

Table 1. Periodic Monitoring of Stack Emission (CEN/TC264/N2046, 2013).

Environmental Medium	Component(s)	Monitoring Method for SRM	EN or ISO standard for SRM	Limit of Detection LoD
stack gas	O ₂	Paramagnetism	EN 14789	≤ 0.20 % of the range
stack gas	Temperature	Thermocouples	IEC Publication 584-2	
stack gas	Flowrate	Differential pressure, vane anemometer et al	EN ISO 16911-1	not applicable
stack gas	Water vapour	Adsorption or condensation/adsorption method; Temperature method	EN 14790	≤ ± 2.0 % of the range
stack gas	CO	Non-dispersive infrared spectrometry	EN 15058	≤ ± 2.0 % of the range
stack gas	SO ₂	Absorption in liquid phase	EN 14791	ion chromatography analyse: 0,05 to 0,2 mg SO ₄ ²⁻ /l; titration method: 1 to 10 mg SO ₄ ²⁻ /l
stack gas	NO _x	Chemiluminescence	EN 14792	≤ +/-2.0 % of the range
stack gas	dust	Gravimetric	EN 13284-1	for dry gases: 0.3 mg/m ³ ; for water saturated gases: 2 mg/m ³
stack gas	NH ₃		-	
stack gas	HCl (Gaseous Chloride content)	Absorption in liquid phase	EN 1911	0.05 to 1 mg Cl/l
stack gas	HF (Gaseous Fluoride content)	Absorption in liquid phase	ISO 15713	0.1 mg/m ³ with a sample volume of 0.1 m ³
stack gas	total organic carbon, TOC	Continuous flame ionisation detector method	EN 12619	not specified
stack gas	Individual gaseous organic compounds	Solid adsorbent/solvent extraction or thermal desorption	EN 13649	not specified
stack gas	PCDD/F	Filter, a condensate flask and a solid or liquid adsorbent	EN 1948 part 1, 2 and 3	not specified
stack gas	PCB	Filter, a condensate flask and a solid or	EN 1948 part 4	depending on method: WHO-TEQ 0.11 to 0,57 pg/m ³)

		liquid adsorbent		
stack gas	Hg (Total)	Filtration and absorption in liquid phase	EN 13211	2.6 µg/m ³ (gas volume of 0.05 m ³)
stack gas	As, Cd, Tl, Sb, Pb, Cr, Co, Cu, Mn, Ni, V (total emission of specific elements)	Filtration and absorption in liquid phase	EN 14385	≤ 5 µg/m ³
stack gas	N ₂ O	Non-dispersive infrared spectrometry	EN 21258	≤ 2 % of upper limit of the lowest measuring range used
stack gas	CH ₄	Continuous flameionisation detector method/gas chromatography	EN 25140 EN 25139	≤ 2 % of upper limit of the lowest measuring range used

Table.2. Continous Monitoring of Stack Emission (CEN/TC264/N2046, 2013)

Environmental Medium	Components	Examples for Monitoring Methods for AMS	EN or ISO standard for SRM	Certification Standard for AMS / Calibration Standard	Limit of Detection LoD*
stack gas	O ₂	Paramagnetism, electrochemical cell, ZrO ₂	EN 14789	EN 15267 EN 14181	≤ 0.40 Vol%
stack gas	Temperature	Thermocouples	IEC Publication 584-2		
stack gas	Flowrate	Ultrasonic, differential pressure, mass flow	EN ISO 16911-2	EN 15267 EN 14181 EN ISO 16911-2	≤ 4.0% of range at lower reference point
stack gas	Water vapour	TDL, FTIR, NDIR with GFC	EN 14790	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	SO ₂	NDIR, FTIR	EN 14791	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	CO	NDIR, FTIR	EN 15058	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	NO _x	Chemiluminescence, NDIR, FTIR	EN 14792	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	Dust	Optical, triboelectric, et al	EN 13284-2	EN 15267 EN 14181 EN 13284-2	≤ 4.0 % of the upper limit of the certification range
stack gas	NH ₃	NDIR with gas	-	EN 15267	≤ 4.0 % of the

		filter correlation, FTIR, TDL		EN 14181	upper limit of the certification range
stack gas	HCl (Gaseous Chloride content)	NDIR with gas filter correlation, FTIR, TDL	EN 1911	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	HF (Gaseous flouride content)	FTIR, TDL	ISO 15713	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	Total organic carbon, TOC	Continous flame ionisation detector method	EN 12619	EN 15267 EN 14181 EN 12619	≤ 4.0 % of the upper limit of the certification range
stack gas	Hg (Total mercury)	Atomic absorbance spectroscope, cold vapor atomic fluorescence spectroscopy	EN 14884	EN 15267 EN 14181 EN 14884	≤ 4.0 % of the upper limit of the certification range
stack gas	N ₂ O	NDIR, FTIR	EN ISO 21258	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range
stack gas	CH ₄	Continous flame ionisation detector method, NDIR, FTIR	EN ISO 25140	EN 15267 EN 14181	≤ 4.0 % of the upper limit of the certification range

*) 2 x repeatability standard deviation at zero according to EN 15267-3 in field test

Some remarks on previous standard measurement methods:

at this moment there does not exist European standard measurement method for periodic measurement of CO₂, but the standard ISO 12039 indicates that in general continuous emission monitoring systems, CEMS, for CO₂-analysis can measure up to about 20 vol% (Note! The preparation of a new standard for the measurement of CO₂ has been started in 2012 in CEN/TC264/WG16 with the title: "Stationary source emissions – Reference method for the determination of CO₂ concentration and mass emissions").

- No standard measurement method for NH₃
- No standard measurement method for amines and its degradable compounds
- No European standard measurement method for aldehydes,
 - o but U.S.EPA Method 323 defines manual method for measuring acetaldehyde emissions and
 - o DNPH method is also commonly used method, detection limit is typically less than 0.1 ppm.
- No European standard measurement method for ethanolamines, amides and nitrosamides

- OSHA (Occupational Safety & Health Administration, USA) method PV2111 describes determination of above mentioned components using sampling tubes containing XAD-2 resin coated with 10% 1-naphthylisothiocyanate (NITC) by weight. Samples are desorbed with dimethylformamide and the amine derivative is analyzed by high performance liquid chromatography (HPLC).

Common remarks on measurement techniques:

- measurement methods for CO₂ and O₂ in high concentrations are not standardized, this would be needed in oxyfuel process
- Ethanolamines, amides, ammonia and nitrosamides needs standardized sampling and analysis methods.
 - Low concentrations are a challenge
 - Possible interferences in sampling and analysis
- Particle emission measurements in post-combustion processes may have challenges due to possible amine mist.

7 Conclusions

Variation of emissions to atmosphere from carbon capture techniques is very wide according to reviewed estimations and pilot scale emission studies. Estimations showed that in oxyfuel and pre-combustion processes, the emissions are likely to decrease. However, emissions from post-combustion using amine based technology are estimated to increase and emissions compounds are not well known yet.

At this moment, there are no standardized sampling and analysis methods for ammonia, amines, ethanolamines, nitrosamines and possible other amine degradates. Standardisation of sampling and analysis methods for those compounds should be performed as soon as possible.

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