Carbon Sequestration Leadership Forum
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CARBON SEQUESTRATION LEADERSHIP FORUM

TECHNICAL GROUP

TASK FORCE ON

INDUSTRY CCUS

Carbon Capture, Utilisation and Storage (CCUS) and Energy Intensive Industries (EIIs)

From Energy/Emission Intensive Industries to Low Carbon Industries

September 2019

Foreword

A net zero human-caused emissions of carbon dioxide missions target requires all activities to develop solutions that drastically reduce emissions of greenhouse gases within their perimeters.

Energy Intensive Industries are crucial for the current economies and their growth, particularly in emerging countries. These industries emit significant amount of CO_2.

This report addresses specifically the role that CCUS is playing and will play to reduce CO_2 emissions in these industries to levels compatible with the overall target to mitigate climate change.
For each of the sectors considered in this report and which encompass the most important EIIs (Steel, Cement, Chemicals, Refining, Hydrogen, Heavy Oil, Natural Gas, Fertilizer, and Waste to Energy), the following questions are addressed:

- How is the sector contributing to today's economies?
- How is its anticipated contribution to the growth of the economies?
- Where are its main geographical origins of production? Where is the production growth anticipated to be?
- What are the present and anticipated future CO_2 emissions of the sector?
- What are the main sources and patterns of CO_2 emissions of a typical plant of this sector?
- What other ways than CCUS exist for reducing its CO_2 emissions?
- What is the development status of CCS technologies applicable to its main sources of CO_2 emissions?
- What are the challenges to the implementation of CCS in this sector?

This report shows, in one volume, the different types of emissions that are encountered in these sectors.
The roles of the different stakeholders who are linked to these activities are addressed.

Views on possible interactions between the different sectors are also proposed: sharing RD&D programmes and results, sharing expertise in different fields, and making mutual profit from the complementarities between the sectors can potentially accelerate the development of CCUS.

The deployment of CCUS in EIIs might contribute to the development of CCUS in other areas, specifically in power generation, for the benefit of the whole society.

Acknowledgements

This report was prepared for the CSLF Technical Group by the core participants in the Carbon Capture, Utilisation and Storage Task Force: Dominique Copin (Total, France, Chair); Mónica García Ortega from the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) in United Kingdom; Claude Lorea from the Global Cement and Concrete Association (GCCA) in United Kingdom; Eric De Coninck and Salvatore Bertucci, both from ArcelorMittal; Pieter Smeets from SABIC in the Kingdom of Saudi Arabia; Sophie Wilmet from the European Chemical Industry Council (Cefic) in Belgium; Yewen Tan, Ahmed Shafeen and Eddy Chui, all from Natural Resources Canada; Fabrice Devaux from Total, France; Damien Valdenaire from Concave in Begium; and Lars Ingolf Eide from the Research Council of Norway.

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A special thank to Yara International, represented by Eystein Leren and Odd-Arne Lorentsen, for writing the fertilizer sections.

Each individual and their respective oragnisations have provided the necessary resources to enable the development of this report.

This report presents a review of current status of the use of Carbon Capture, Utilisation and Storage in energy intensive industries. It does not necessarily represent the views of the individual contributors or their respective employers.

EXECUTIVE SUMMARY

Conclusions and recommendations

- Energy Intensive Industries (EIIs) are taking various routes to reduce CO_2 emissions. Non-CCUS (Carbon Capture, Utilisation and/or Storage) alternatives are important but by themselves are unlikely to provide the needed reduction fast and large enough to resolve the pressing climate issues. In particular, some process-related emissions in the industry will be more difficult to eliminate if Carbon Capture is not considered.

- The benefits of CCUS to the whole society can be much higher than its current costs.

- Nevertheless, CCUS is capital intensive, and presents operational challenges: it needs support, incentives and creative business models to stimulate widespread large-scale implementations.

- CO_2 utilisation options can provide many EIIs a revenue stream to offset the costs of carbon capture. These options can lessen the dependence on government subsidies, while building experience, and promoting and developing more industrial scale demonstrations of carbon capture in EIIs and power, as well as infrastructure for transport and storage. Utilisation may play a role in increasing the public acceptance of the whole CCUS industry as it refers to circular economy. However, the climate mitigation potential for some utilisation approaches can be limited.

- Research, Development and Demonstration (RD&D) must be accelerated to drive down CCUS costs. Although each EII has its own specific constraints and opportunities in reducing CO_2 emissions, there are common issues that can benefit from stronger cooperation amongst different sectors. If knowledge sharing of common issues and lessons learnt is established, efficient RD&D in CCUS can be carried out to accelerate the cost reduction and efficiency improvement for the benefits of multiple EIIs. Topics for joint RD&D include:
    - Reducing combustion related CO_2 emissions by CCUS, which share similar characteristics across many industries and could utilize similar carbon capture technologies,
    - Taking advantage of related CO_2 solutions in different EII sectors (e.g. concrete or cement curing, enhanced oil recovery (EOR), and the production of fuels or chemicals). Understanding the real need for CO_2 purification in line with its application can minimize the cost of capture and improve the economics of CCUS,
    - Reducing energy consumption for the CO_2 capture, via deep heat/energy integration in the plants as well as with district heating, and
    - Development of shared transport infrastructures.

  In addition, EIIs can develop customized R&D CCUS projects focusing on reducing CO_2 emissions from their specific processes.

- The role of EIIs for the development of CCUS:

  - Cooperating with the early adopters of CCUS both at the RD&D and project levels (like in Norway), especially in lowering the cost of carbon capture,
  - Seizing opportunities to develop interactions between different industrial sectors for the benefit of CCUS,
  - Developing circular business models via the utilisation of CO_2 as an alternative carbon resoure,
  - Encouraging and cooperating on the development of transport and storage infrastructures with the relevant stakeholders (e.g. oil and gas sector, gas network companies, governments or states), and
  - Cooperating on the transport and storage infrastructures.

- The role of government for the development of CCUS:
  - Providing a level playing field so that the EIIs can make sound profitable long-term investment decisions on CCUS in a global market (e.g. regulations, support mechanisms/incentives, joint RD&D,) to prepare themselves to meet the Paris goal, and contribute to the effort of the countries to achieve their target,
  - Providing certainty and predictability to EIIs that they will consistenly support CCUS developments,
  - Supporting appropriate infrastructure developments required for CO_2 transportation from sources to storage or utilization,
  - Supporting the business models for CCUS,
  - Introducing effective measures to encourage procurement of low-carbon industrial products from a full-value chain perspective, development of infrastructures and avoid carbon leakage, and
  - Encouraging and supporting knowledge sharing amongst EIIs and other stakeholders.

- The role of the oil and gas sector will be to bring its expertise to develop CO_2 infrastructure and storage capacities to alleviate the risks undertaken by EIIs willing to invest in CCUS. This sector, being in close relationship with all EIIs via CO_2 transport and storage, would be in a good position to help develop collaborations between EIIs.

- End-use consumers must be made aware of the fact that low-carbon industrial products may incur only modest additional costs to them, while suppliers of the whole product chain (for example construction companies and car manufacturers) are likely to be able to recover appropriate expenses.

- The role of national and international CCUS organisations will be to advocate to the main relevant stakeholders (EIIs, governments and citizens, oil and gas sector, end users…) the paramount importance of developing CCUS in EIIs in order to meet the challenge of climate change mitigation.

- It must be noted that CCUS is not the only contributor to climate change mitigation, although its role is key. CCUS complements, rather than competes, with other low-carbon solutions to help the transformation to a decarbonized society.

Summary

Energy Intensive Industries are key building blocks of all economies.

1. This report considers production of steel, cement, chemicals, refining, hydrogen, natural gas, heavy oil, fertilizers, and waste to energy, It should be noted that presently hydrogen production is not yet an established industry by itself. It is treated separately in this report because of its emerging importance.

2. EIIs are essential in today's economies. Their products are needed to build infrastructures, and supply a range of commodities and consumer goods, in particular to increase the standard of living for a large part of the world's population.

3. Most of the EIIs are expected to grow in the next decades because they are crucial to economic growth. The highest growth is, and expected to continue to be, in countries going through rapid developments and transformations.

EIIs are needed for climate change mitigation and adaptation.

4. EIIs will play a key role for climate change mitigation:
    - By providing materials to other industries which are developing low carbon energy solutions for the benefit of the whole society,
    - By providing products (e.g. clean hydrogen) which can be used to lower the CO_2 emissions from some energy intensive production processes (e.g. steelmaking), and
    - By supplying current products required by custromers but with continuous carbon footprint reduction.

5. EIIs will be key to climate change adaptation because many adaptation measures will require significant investments in green-field or brown-field infrastructure projects adding to the demand for EIIs products.

EII industries are intensive in CO_2 emissions.

6. The cumulative global CO_2 emissions from the identified EIIs amount to about 25% of the total CO_2 emissions. Targeting their emissions for reduction over the next decades is a necessary condition for achieving the goals of the Paris agreement. The IEA Energy Technology Perspective 2017 indicates that the industrial CO_2 emissions will have to be reduced by 50% by 2050 in the 2 ^{o}C scenario (2DS) and more than 70% in the beyond 2 ^{o}C scenario (B2DS).

7. In addition to generating CO_2 by burning fossil fuels for energy requirement, many of the EIIs inherently produce CO_2 in their processes. This is the case for
    - Cement production where around 60% of the emissions are due to the decarbonation of limestone,
    - Steel production from iron ore where around 50 % of the emissions are due to the ferrous oxide reduction, including the coke-making process,

- Hydrogen production from fossil fuels, mostly natural gas, where around 60% come from the reforming process,
- Natural gas treatment as in separation of native CO_2 contained in gas reservoirs from methane, where almost all of the emissions are due to the composition of the mined gas with smaller contribution from energy consumption,
- Chemical industries when using coals to produce liquids or olefins, and
- Fertilizers industries, where around 70% of the emissions are due to the process.

EIIs are actively working on decreasing CO_2 emissions but there are obstacles.

8. All major industries have ongoing work to reduce energy-related CO_2 emissions. Examples include:
   a) Developing more efficient combined heat and power generation,
   b) Replacing fossil fuels with sustainable biofuels, low-carbon hydrogen, or low-carbon electricity to produce heat, and
   c) Replacing fossil feedstock with low-carbon hydrogen or sustainable biomass in the processes.

   These measures for CO_2 reductions may have limitations. For example, combined heat and power generation efficiency may give reductions not exceeding 15 to 20% of CO_2 emissions, and availability of low carbon electricity and/or sustainable biomass require significant economic investments.

9. Many major industries are working on alternative processes to reduce process-CO_2 emissions, for example in the steel industry, and in new cement or concrete chemistries. Most of the new innovative technologies are still at low technology readiness levels and unlikely to be ready for full implementation in the near future.

   In addition, many EIIs are “capital intensive industries” with significant infrastructure assets that have life durations covering several decades in most cases. Process changes may result in stranding important assets, thus impeding a fast and complete substitution of presently high CO_2-emitting processes with new lower emitting ones.

CCUS will play an essential role in decreasing the emissions from EIIs

10. CCUS will be essential to fully achieve close to zero net CO_2 emissions in the EIIs. For most of EIIs, the technology should be considered as a mature pathway to reduce CO_2 emissions (IEA ETP 2017), for the following reasons:
    - From capture to storage via transport, CCUS has been applied around 20 times at industrial scale, the vast majority of them being in EIIs.
    - The post-combustion CCUS approach can generally be implemented without a complete replacement of the core-process of these industries. This makes CCUS an important consideration to address the urgency of reducing EII CO_2 emissions.
    - CCUS in EIIs will provide opportunities of developing negative emissions projects, via the combining use of biomass and CCS, and will be a contributor to BECCS developments.

11. Emissions from EIIs generally have higher CO_2 concentrations in the process gas streams than those from fossil-based power utilities. This could lead to lower cost per ton of CO_2 captured from EIIs compared to power generation. CO_2 emission rates, stream pressure, impurities are among other factors which affect the cost of capture both negatively and positively.

12. The availability of waste heat (low to high grade) in EII processes can potentially benefit CO_2 capture as most carbon capture processes incur significant energy penalties. This would offer co-operation opportunities between EIIs.

CCUS in EIIs: On-going Efforts and Challenges

13. Some EIIs are prime to apply CCUS at industrial scale (in hundreds of thousands of ton CO_2 per year):
    - Natural gas treatment with extraction of CO_2 from mined gas. Many of the current CCUS projects are in this field.
    - Hydrogen production, steel production, fertilizer production, heavy oil production all have projects in operation.
    - CO_2 from an ethylene glycol plant used for production of methanol and urea in Saudi Arabia.
    - There are multiple demonstrations of novel concrete-making using CO_2 in North America and Europe.

14. In industries where no industrial scale project is in operation, pilot scale testing is being conducted, and industrial scale projects are being considered. These are essential steps prior to industrial scale demonstration:
    - The waste-to-energy industry has small pilots with CCUS in Japan, Netherlands and Norway.
    - Cement industry has completed pilots with CO_2 capture from the kilns in Norway and has other pilot projects in operation (examples: LEILAC, CEMCAP, and CLEANKER).
    - Industrial scale CCUS applications for both waste-to-energy and cement industries are being considered in Norway.

15. Presently, CCUS is a capital intensive technology, resulting in significant increase of production costs of the Energy Intensive Industries. However,
    - A wider view on CCUS shows that the benefits and value of CCUS to the whole society can be much higher than its current evaluation of costs.
    - Significant cost reductions will be achieved through implementation of an increasing number of industrial projects. Also, there are significant worldwide R&D programs focusing on decreasing the capital and operating expenses (CAPEX, OPEX) and energy penalties associated with CCUS.

    CCUS will result in further material cost increases (around 30 % more for steel and 80 % more for cement). However, these cost increases will likely result in marginal overall additional expense for end-use consumers (e.g. <1 % for a car and <3% for a house), because materials generally contribute to only a small fraction of overall consumer product costs. Nevertheless, some intermediate players in the product chain presently have little incentive to buy low carbon EII intermediate products (like cement and steel) with significant extra costs.

16. CCUS and CCU will offer opportunities for CO_2 utilisation. This is the case for the cement and concrete and the chemical industries. Some CO_2 utilisation options may not have the same mitigation potential as CO_2 storage in geological formations or CO_2 utilisation through mineralisation. Nonetheless, these technologies can provide many EIIs a revenue stream to offset the costs of carbon capture, lessening the dependence on government subsidies, while promoting more industrial scale demonstrations of carbon capture in EIIs.

17. Carbon leakage: Many EIIs compete on international markets. For a company to invest in CCUS there is a risk of being disadvantaged by competitors not following the same low carbon pathway.

18. EIIs are generally unfamiliar with operations associated with storage capacities and monitoring of CO_2 in geological formations. In most cases, EIIs will likely limit their operations to CO_2 capture. Different business models are probably needed in which transport and geological storage of CO_2 will be handled by competent entities, like the oil and gas sector, more familiar with these aspects of CCUS. These models will duly consider the risks of failure along the chain from capture to utilisation/storage.

19. Operational issues on the capture side could also be challenging. Some technologies might require large modifications for its integration in the industrial facility. Some industries will also need to develop new expertise to deal with these modifications and new operational integration.

20. CCUS investment will reduce the flexibility to close an EII plant. This is particularly concerning for plants located in areas with relatively low growth potential as in an already industrialized region facing severe international competitions.

21. EIIs will need to recover their costs associated with applying CCUS. Incentives and an international level playing field must be established to provide conditions for sound profitable long-term investment decisions on CCUS.

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List of Acronyms

2DS	2 ºC Scenario
ACTL	Alberta CO_2 Trunk Line
ATR	Autothermal Reforming
B2DS	Beyond 2 ºC Scenario
BECCS	Bio-energy and CCS
BEIS	United Kingdom Department of Business, Energy and Industrial Strategy
BOF	Blast Oxygen Furnace
CaL	Calcium Looping
BOFG	Blast Oxygen Furnace Gas
CAP	Chilled Ammonia Process
CAPEX	Capital expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation, and Storage
CDR	Carbon Dioxide Removal
CEFIC	The European Chemical Industry Council
CHP	Combined Heat and Power
CO_{2e}	CO_2 equivalent
CSI	Cement Sustainable Initiative
CSLF	Carbon Sequestration Leadership Forum
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EC	European Commision
ECRA	European Cement Research Academy
EIA	Energy Information Administration (USA)
EII	Energy Intensive Industry
EOR	Enhanced Oil Recovery
ETP	Energy Technology Perspectives
ETC	Energy Transition Commission
EU	European Union
FAO	United Nations Food and Agriculture Organisation
FEED	Front End Engineering and Design
GCCSI	Global CCS Institute, Australia
GE	General Electric
GHG	GreenHouse Gas
Gt	Billion (10^9) tonnes
ICCA	International Council of Chemical Associations
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas Research and Development Programme
IFA	International Fertilizer Association
IMO	United Nations International Maritime Organisation
IPCC	United Nations Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kt	Thousand tonnes
LFG	Land Fill Gas
LNG	Liquefied Natural Gas
MDEA	Methyl Di-Ethanol Amine
MEA	MonoEthanolAmine
MMb/d	Million (10^6) barrels per day
MSW	Municipal Solid Waste

Mt	Million (10^6) tonnes
OECD	Organisation for Economic Co-operation and Development
OGCI	Oil and Gas Climtet Initiative
OPEX	Operational expenses
OTSG	Once Through Steam Turbine
PG	Policy Group of CSLF
POX	Partial Oxidation
PSA	Pressure Swing Absorption
R&D	Research and Development
RD&D	Research, Development and Demonstration
RTS	Reference Technology Scenario
SAGD	Steam-Assisted Gravity Drainage
SEWGS	Sorbtion Enhanced Water Gas Shift
SMR	Steam Methane Reforming
TCM	Technology Centre Mongstad (Norway)
TG	Technical Group of CSLF
TGROBF	Top Gas Recycling Oxygen Blast Furnace
TRL	Technology Readiness Level
TUC	Trades Union Congress
UK	United Kingdom
UKPIA	UK Petroleum Industry Association
UN	United Nations
USA	United States of America
VPSA	Vacuum Pressure Swing Absorption
WBCSD	World Business Council for Sustainable Development
WEC	World Energy Council
WGS	Water Gas Shift
WtE	Waste to Energy

1. Introduction

1.1. Introduction to Carbon Sequestration Leadership Forum (CSLF)

The Carbon Sequestration Leadership Forum (CSLF; https://www.cslforum.org) is a Ministerial-level international climate change initiative that focuses on the development of improved cost-effective technologies for the separation and capture of CO_2 for its transport and long-term safe storage. Its mission is to facilitate the development and deployment of such technologies via collaborative efforts that address key technical, economic, and environmental obstacles.

The CSLF comprises a Policy Group (PG) and a Technical Group (TG). The PG governs the overall framework and policies of the CSLF, and focuses mainly on policy, legal, regulatory, financial, economic, and capacity building issues. The TG reports to the PG and focuses on technical issues related to Carbon Capture, Utilization and Storage (CCUS) and on CCUS projects in member countries.

1.2. Terminology

For the purpose of this document, the following definitions apply (note that these may differ from other definitions):

- The term carbon capture and storage (CCS) is used when CO_2 is captured from its source of production and transported to a geologic storage site for long-term isolation from the atmosphere.
- The term Carbon capture and utilization (CCU) is used when the CO2 is used as an alternative source of carbon for the production of products containing carbon (e.g. chemicals, fuels, polymers). Permanent CO2 emissions avoidance can be evaluated using appropriate methodology and system boundaries.
- The term carbon capture, utilization, and storage (CCUS) is used to cover both CCU and CCS, as well as the combination where all or part of the CO_2 is used before being stored for long-term isolation from the atmosphere. The combination includes instances in which CO_2 is used to enhance the production of hydrocarbon resources (such as CO_2-enhanced oil recovery, EOR), or in mineralization processes, such as the formation of mineral carbonates, thereby permanently isolating the CO_2 from entering the atmosphere.

1.3. Task force mandate and objectives of report

At the CSLF Annual meeting in Tokyo, Japan, in October 2016, the CSLF Technical Group formally moved forward with a task force to investigate the opportunities and issues for CCUS in the industrial sector.

The Industry CCUS Task Force was mandated to

- Summarize current knowledge on CO_2 emissions from the industry sector in industry,
- Identify the role of the sector in present regional and global economics, as well as in future economics without CCUS,
- Identify alternatives to CCUS,
- Identify status and needs for CCUS in the industry sector and point to technical solutions that will benefit the industry sector in their efforts to reduce CO_2 emissions, and
- Include conclusions and recommendations for consideration by CSLF and its member countries.

France volunteered to serve as chair of the task force.

During the course of the work, it became apparent that other organisations were working on the same topic and issued reports. Therefore, the mandate was adjusted to avoid duplication and the objective changed to:

- Summarize current knowledge on CO_2 emissions from the industry sector in industry,
- Give examples of non-CCUS technologies for CO_2 reductions in industrial sectors,
- Identify where CCUS can complement other technologies to reduce CO_2 emissions industrial sectors, and
- Give recommendations for consideration by CSLF and its member countries.

It is important to note that the main objective of the report is to identify the role of CCUS to reduce CO_2 emissions for energy intensive industries (EIIs).

1.4. Structure of the report

Chapter 1 gives the background for the Task Force and its report, as well as an overview of the industry's contribution to global CO_2 emissions and the role it can play towards net-zero carbon emissions. Chapter 2 summarises some key information on the roles of industry in economics. Chapter 3 reviews how the industry can contribute to reduced CO_2 emissions by alternative or new fuels, processes and materials. Chapter 3 is the heart of the report from the industry points of view. Chapter 4 summarises the status and gaps of CCUS technololgies for industry. Chapter 5 gives a very brief summary of potential interactions between the EIIs and how CO_2 may be utilised.

At the end of the report, there are ten technically detailed annexes – one for each of the nine industries and one that is an extensive summary of the status and gaps for CCUS technologies, and expansion of Chapter 4. Annex 10 and Chapter 4 are intended for those readers that are mostly interested in the CCUS technologies and their applications and less so in details of the industrial processes.

The references for all parts of the report, including the annexes, are found in Chapter 6.

1.5. Motivation, industry's role in global CO_2 emissions

The industry sector is a major contributor to global CO_2 emissions. In 2014, total energy-related direct global emissions of CO_2 amounted to approximately 37.1 Gt[1] (Olivier and Peters, 2018), of which 8.3 Gt CO_2/year were direct emissions from industry and 13.6 Gt CO_2/year from the power sector. Thus, the industry was responsible for almost 25% of total CO_2 missions, Figure 1.1.

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[1] Total greenhouse gas emissions (GHG) were significantly higher, 50,9 Gt CO2 equivalents in 2017, excluding land use (Olivier and Peters, 2018))

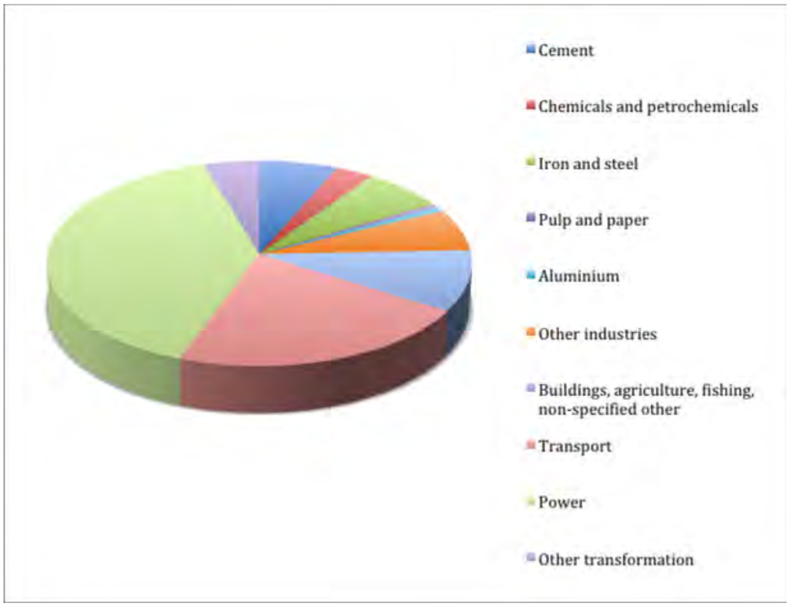


Figure 1.1. CO_2 emissions 2014 distributed on sectors (IEA, 2017)

The International Energy Agency (IEA, 2017) describes three scenarios for the prediction of future CO2 emissions, see box 1.

Figure 1.2 shows how much future CO_2 emissions from industry may have to be reduced shall the world reach the 2DS and the B2DS targets, compared to the reference scenario. In the 2DS, the industry sector will have to reduce emissions by approximately 3 Gt CO_2/year, and in the B2DS by 6 Gt CO_2/year. Even with these reductions, there are strong indications that the industry sector will be the main contributor to CO_2 emissions towards the middle of the 21st century.

BOX 1
Emissions Reduction Scenarios

Energy Technology Perspectives 2017 (IEA 2017a) explores the potential of technologies to push emissions to a 2°C level, referred to as the 2°C Scenario (2DS), and below the level associated with a 2°C limit, referred to as the Beyond 2°C Scenario (B2DS). B2DS charts a trajectory for the energy sector resulting in a 50% chance of limiting the rise in temperature to 1.75°C.

The Reference Technology Scenario (RTS) takes into account today's commitments by countries to limit emissions and improve energy efficiency, including the nationally determined contributions pledged under the Paris Agreement. By factoring in these commitments and recent trends, the RTS already represents a major shift from a historical "business as usual" approach with no meaningful climate policy response. The RTS requires significant changes in policy and technologies in the period to 2060 as well as substantial additional cuts in emissions thereafter. These efforts would result in an average temperature increase of 2.7°C by 2100, at which point temperatures are unlikely to have stabilized and would continue to rise.

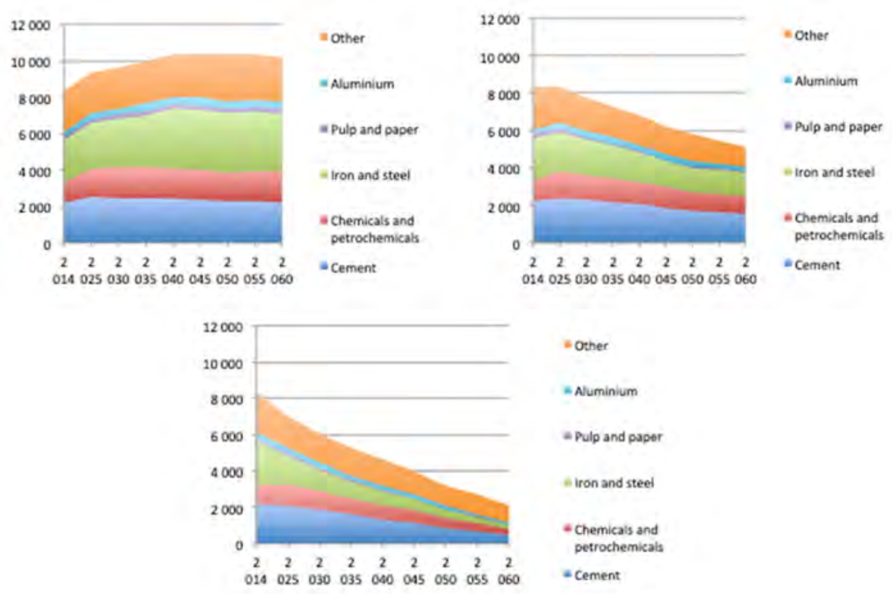


Figure 1.2. CO_2 emissions in Mt CO_2/year from industry in RTS (upper left), 2DS (upper right and B2DS (lower) scenarios (from IEA, 2017).

1.6. The role of CCUS in the industry sector towards net-zero carbon emissions

Substantial reductions of CO_2 emissions from industry are needed to reach the targets of the Paris Agreement. Due to limited possibilities to reduce the emissions from different industrial processes, it is unlikely that sufficient industry contribution to the targets can be reached without CCUS (Energy Transition Commission (ETC) 2018a,; United Kingdom (UK) CCUS Cost Challenge Task Force, 2018).

As shown in Figure 1.3, IEA (2017) estimates that in the 2DS, about half of the reductions by 2050 may be achieved by new process technologies, more efficient energy use and fuel transitions, whereas in B2DS these means can only give about 1/3 of the needed reductions of CO_2 emissions by 2050. CCS is believed to be responsible for the rest, approximately1.5GMt CO_2/year will have to be captured and stored from industry by 2050, and approximately 3 Gt CO_2/year in B2DS.

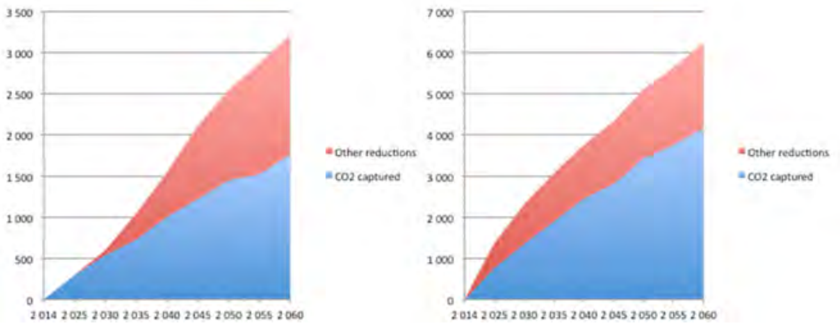


Figure 1.3. CO_2 reductions in the industry sector split between CCS and other means, in Mt/year, 2DS (left) and B2DS (right)

The industry sector is predicted to have to take a larger share of the total CO_2 captured and stored in B2DS than in 2DS, as indicated in Figure 1.4. Despite this, the sector may be the largest CO_2 emitter in 2060 in both scenarios, see Figure 1.5. Other transformations go CO_2-negative in 2DS and both power and other transformations must be negative in B2DS, resulting in neutral or slightly net negative emissions by 2060.

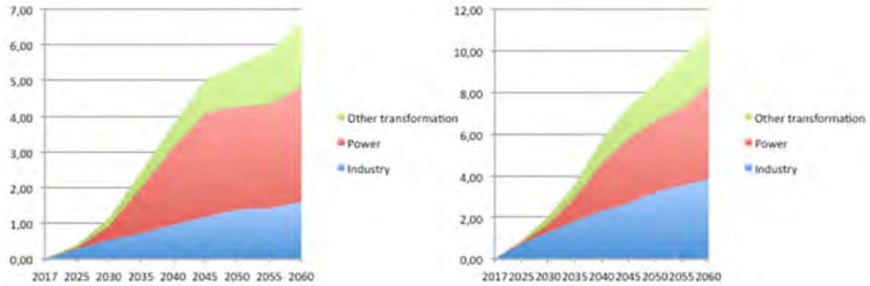


Figure 1.4. CO_2 that has to be captured from different sectors in 2DS (left) and B2DS (right), in Gt/year

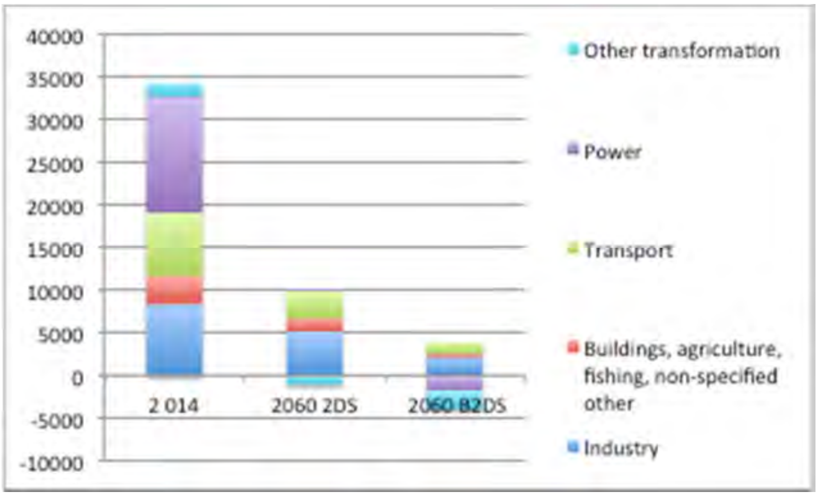


Figure 1.5. CO_2 emissions by sector in 2014 and in 2060 in 2DS and B2DS, in Mt CO_2/year

1.7. Value of CCUS to the economy

The Oil and Gas Climate Initiative (OGCI, 2018) has summarized the potential value of CCUS to the UK economy. While stating that implementation of CCUS has been slow and the debate has been focussing on the high investment costs, OGCI points out that:

- CCUS can deliver very substantial reductions of CO_2 emissions towards reaching climate goals, e.g. by comparing reductions from one single large scale project (Shell's Quest in Canada) to offshore windfarms and the introduction of electric cars (operation only).
- CCUS can make the UK economy at least £ 30 000 million more competitive in a decarbonised world than without CCUS.
- CCUS will generate economic value via job retention and creation. The Trades Union Congress (TUC, 2014) estimated that as much as 30 000 persons could be employed in CCUS by 2030 if 20% of current power generation was abated, and that CCUS would contribute to safeguarding 160 000 direct employees in energy intensive industries. Sintef (2018) indicated noticeable impact of CCUS on the job market in Norway.
- CCUS can lower energy bills in the UK.
- The OGCI document also stated that CCUS might be the only solution to achieve net-zero emission in parts of the industrial sector.
- CCUS can produce net negative emissions through use of bio-energy combined with CCS.

- CCUS can work with renewables to deliver reliable and stable power (see also IEA Greenhouse Gas R&D Programme (IEAGHG) 2017).

Several of the statements in OGCI (2018) have been corroborated in UK documents, e.g. by the UK CCUS Cost Challenge Task Force (2018), Element Energy (2018) and the UK Committee on Climate Change (2018), as well as by Global CCS Institue (GCCSI, 2018).

On a global scale the Intergovernmental Panel on Climate Change (IPCC 2014), found that achieving an atmospheric concentration of 450 parts per million (ppm) CO_2 without CCS is more costly than for any other low-carbon technology, by an average of 138%. TUC (2014) stated that CCS could save 40 % of the cost of meeting a 50 % global CO_2 reduction by 2050.

Finally, it must be commented that the IPCC report on global warming of 1.5 ºC (Special Report 15, IPCC, 2018) showed that CCS was essential to reach the 1.5 ºC target in pathways with no or limited (< 0.1 ºC) temperature overshoot. These scenarios will require some carbon dioxide removal (CDR), including direct air capture (DAC) and bioenergy with CCS (BECCS). In the overshoot scenario, reliance on CDR is strong.

1.8. The industries considered in more detail in this report

This report will consider the industries with the largest CO_2 emissions (Figures 1.1 and 1.2) in some detail: steel, cement, chemicals, oil refining, hydrogen production, natural gas production, heavy oil production, fertilizers, and waste-to energy (WtE). Fertilizers and hydrogen are part of the chemical industry but are treated separately here because of their present (fertilizers) and anticipated future (hydrogen) importance. Therefore, emission numbers from production of these items can neither be simply added to those from the other EIIs, nor to each other. The chemical industry is very broad and all products have not been covered.

The industries considered here cumulatively emit 6.0 – 6.5 Gt CO2/year, which means that the achievement of deep decarbonisation will play an important role in combating climate change.

2. The role of industry in global and regional economics

This chapter summarises some key information and descriptions of present and possible future production and of some the applications of the products for the various EIIs. The purpose is to give a perspective of the roles of the industries in the global economy.

2.1. The steel industry

Steel is essential and integral to economic development because of its properties: strength, durability, recyclability and versatility.

- Steel is 100% recyclable, either through re-use or remanufacturing. Today, steel is the most recycled material in the world, with about 30% of steel being produced from recycling. Over 650 Mt of steel is recycled annually, including pre- and post-consumer scrap.
- Steel is one of the most efficient modern construction materials. It offers the highest strength-to-weight ratio amongst commonly used materials and is exceptionally durable.

The Steel industry is mainly involved in three sectors, which consume almost 80% of the global production:

- **Buildings and Infrastructures** (52%): The possibilities for using steel in buildings and infrastructure are limitless. Steel is used in reinforcing bars and structural sections, roofing and insulating panels but also in heating or cooling equipment, internal fittings such as rails, shelving and stairs, and much more.
- **Transport (**12%): In 2015, around 90 million vehicles were produced worldwide. Steel used per vehicle is 900kg on average, totaling approximately 80 million tons of steel used for the automotive sector. Besides automobiles, steel is also used for building rails, trains, ships and containers.
- **Mechanical construction** (14%): Steel is used in electricity pylons, to make offshore oil platforms and it reinforces concrete structures in hydroelectric power stations. No generator, transformer or electric motor could be operated without electrical steels needed to transform electrical power into usable energy.

Today roughly 5 million people work in steelmaking (including contractors) and a further 1 million in steel service centers, batch galvanizing plants and steel trading.

Figure 2.1.1 shows the split of production by regions.

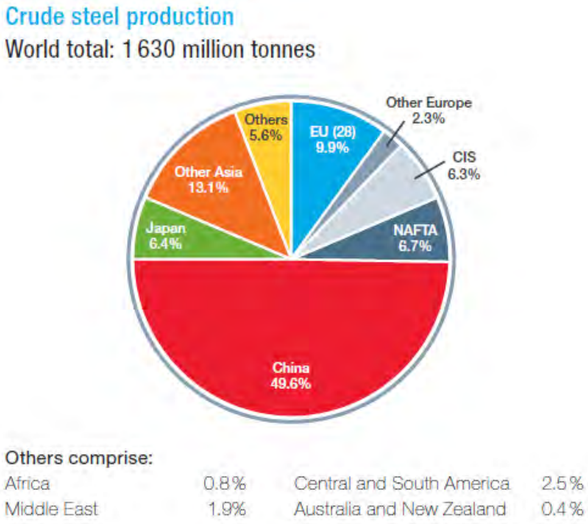


Figure 2.1.1 Split of steel production by regions

From 2000 to 2015, the share of steel production by China has risen from 15% to 50%. In the meantime, the share by EU has dropped from 25% to 12%.

There are few alternatives to steel. At first glance, materials that weigh less than steel, such as aluminium, magnesium and plastics, may appear to be interesting alternatives. However, when the total life cycle of material (Figure 2.1.2) is taken into account, steel is very competitive, owing to its properties mentioned here above.

Figure 2.1.2. The life cycle of steel.

Table 2.1.1 shows the anticipated growth in steel use by regions.

Table 2.1.1. Expected growth in steel demand 2015-2025 by region and user industry

Growth perspectives In steel demand	Western Europe		Central Europe		Emerging Countries Asia		North America		Latin America		Middle-East and Turkey	
	2015	**2025**	**2015**	**2025**	**2015**	**2025**	**2015**	**2025**	**2015**	**2025**	**2015**	**2025**
Automotive	++	+	++	++	+	++	++	+	=	++	+	++
Construction	=	+	+	+	=	+	+	+	-	+	=	+
Mechanicals	+	+	+	+	=	+	+	+	=	+	+	+

Source: Coface.
++ stands for high expected growth, + stands for average expected growth;
= stands for no expected growth; **-** stands for expected contraction.

Growth is expected to be positive in all major markets, with an acceleration in the construction sector (the largest market for steel) in emerging areas in Asia, South America and the Middle-East.

2.2. The cement industry

Concrete is essential for building houses, offices, railways, dams, tunnels, bridges, water and sewage systems. It is also a key enabling component in the low carbon society and economy as well as the circular economy. Thanks to the inherent properties of concrete such as thermal mass, this industry can contribute significantly to sustainable infrastructure construction and energy efficiency. Concrete is 100% recyclable thus ensuring an optimal use of raw materials.

Cement is the glue that holds concrete together. Windmills, high-speed trains, road infrastructure, energy-efficient cities will all require concrete and cement. There is currently no other material that can replace cement or concrete in terms of effectiveness, price and performance for most purposes.

Total world cement production was estimated 4.2 Gt in 2014 and is expected to grow to 5.1 Gt by 2050 (IEA, 2017). By then, the production in the Americas will double the 2014 level and the largest growth will be in India and Africa (tripling 2014 production) according to the IEA and Cement Sustainability Initiative (CSI, 2018). Chinese production, however, is expected to decrease.

Cement production is energy-intensive and accounts for almost 7% of global anthropogenic emissions of carbon dioxide. In light of the anticipated growth in production, the cement industry will have to balance growing demand with the need to reduce emissions in order to provide the market with sustainable products. In so doing, the cement industry can be a strong contributor to the local economy with a high multiplier effect.

Figure 2.2.1 highlights the world major producers and production by regions and countries

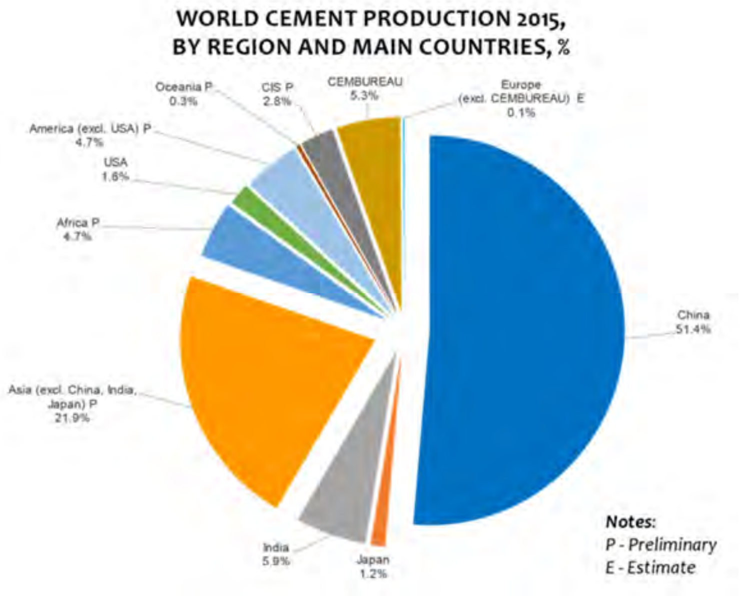


Figure 2.2.1. Global cement production in 2015 by region and/or country.

Note: in this figure, CEMBUREAU means European production from members of CEMBUREAU, and Europe means production from companies which are not members of CEMBUREA (courtesy CEMBUREAU).

2.3. The chemical industry

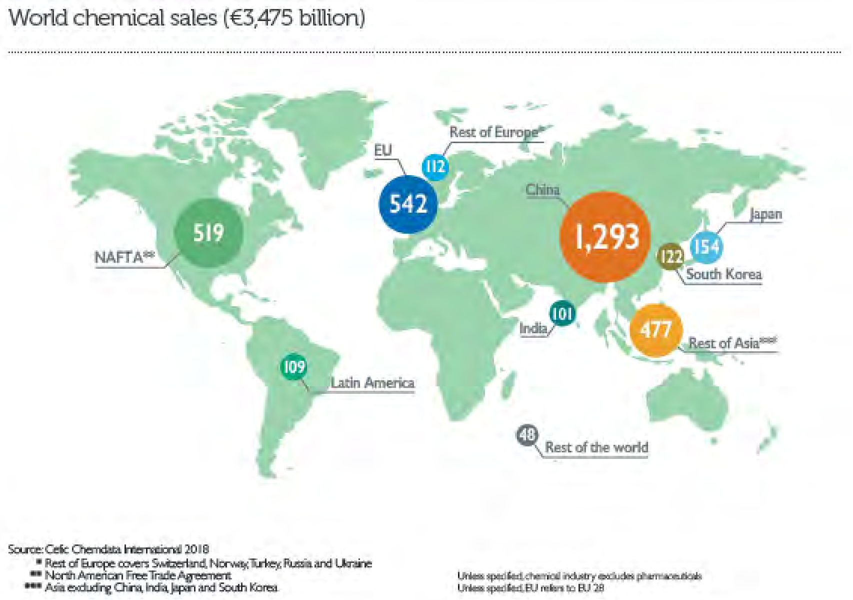
Products from the chemical industry are found in everyday life, ranging from packaging materials, health care products, construction materials, and consumer electronics to materials required for low-carbon energy transition including light-weight solutions in transportation, insulation materials, wind mills, PV panels and batteries. In addition, the growing world population, in combination with increasing living standards are further driving the growth in the chemical industry.

Present and projected production of chemicals

World chemicals turnover was valued at €3,475 billion in 2017. Global sales grew by 4.6% between 2015 and 2017, from €3,323 billion to €3,475 billion (Cefic Chemdata International, 2018). The geographic distribution of world chemicals sales is shown in Figure 2.3.1.

Although competition in China's chemical market is currently intensifying and demand growth is weaker than in the past, China still offers a huge and attractive market, for both chemical suppliers and their associated industries. Chemical producers with high technological capabilities and innovative products are expected to benefit from a robust growth trend in China, from increased exports or via local investments. To what extent depends on the competitive situation in each market segment and the development of final customer markets.

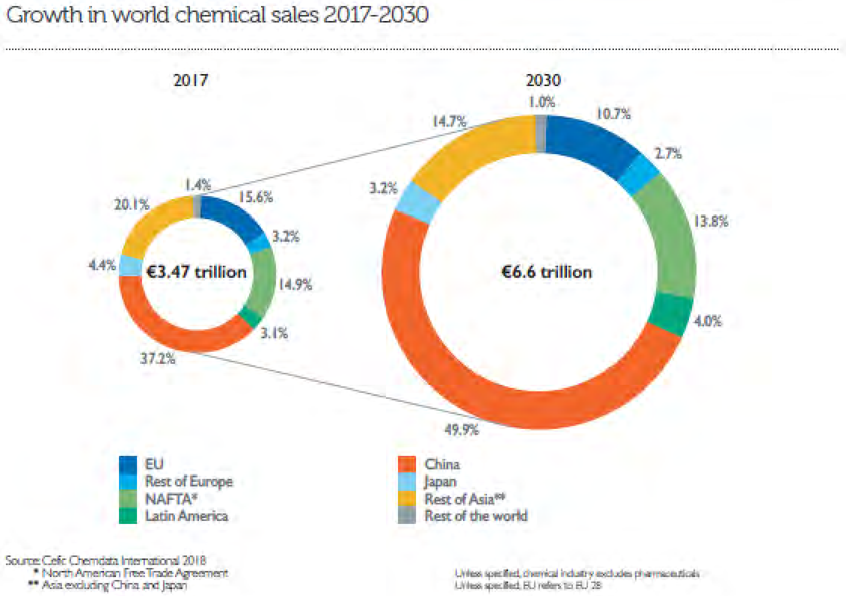
Long-term analysis shows that the overall growth of chemicals demand and production in emerging regions is a trend expected to continue. World chemical sales are expected to reach the level of €6.6 trillion by 2030. With 49.9 % of world market share, China will hold the top ranking in sales, followed by Canada, Mexico and the United States as a whole and the EU union. Chemical sales in Asia may double those of the EU Union, Figure 2.3.2.


World chemical sales (€3,475 billion)

Source: Cefic Chemdata International 2018
* Rest of Europe covers Switzerland, Norway, Turkey, Russia and Ukraine
** North American Free Trade Agreement
*** Asia excluding China, India, Japan and South Korea

Unless specified, chemical industry excludes pharmaceuticals
Unless specified, EU refers to EU 28

Figure 2.3.1. World sales of chemicals distributed by regions and countries **(source: https://cefic.org/app/uploads/2018/12/Cefic_FactsAnd_Figures_2018_Industrial_BROCHURE_TRADE.pdf)**



Source: Cefic Chemdata International 2018
* North American Free Trade Agreement
** Asia excluding China and Japan

Unless specified, chemical industry excludes pharmaceuticals
Unless specified, EU refers to EU 28

Figure 2.3.2. Projected growth of world chemicals sale 2017-2030 (source: https://cefic.org/app/uploads/2018/12/Cefic_FactsAnd_Figures_2018_Industrial_BROCHURE_TRADE.pdf)

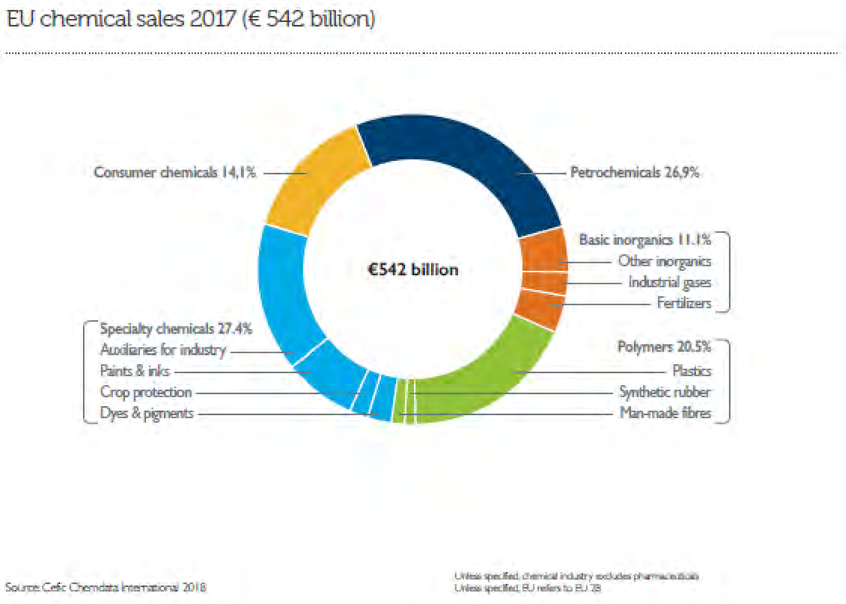
Diversity of the Chemical Industry

The chemical industry is complex and heterogeneous. Its diversity of products, production routes and feedstock is very extensive. Feedstock ranges from coals to oil and gas and their derived products. The chemicals are often produced via a variety of process routes. In the future, chemical recycling of waste and alternative carbon sources from biomass and CO_2, as well as new process technologies will generate more new process routes for this industry.

The output from the chemical industry covers three broad product areas: base chemicals, specialty chemicals and consumer chemicals:

- Base chemicals covers petrochemicals and their derivatives (polymers) along with basic inorganics. These commodity chemicals are produced in large volumes and sold in the chemical industry and other industries. Methanol, ethanol, ethylene and propylene (and the derived polyethylene and polypropylene), butadiene (and derived rubbers), methyl tert-butyl ether (MTBE), benzene (BTX) and ethylene glycol are some of the major products under base chemicals. The inorganic basic chemicals subsector includes production of chemical elements, inorganic acids such as sulphuric acid, bases such as caustic soda, alkalis and other inorganic compounds such as chlorine.
- The group “specialty chemicals” is by far the most heterogeneous group with regard to products, applications, production processes, health, safety denvironmental (HSE) requirements and business structure. This group of chemicals include the variety of chemical ingredients necessary for making consumer goods like for soaps, detergents, other cleaning and polishing products, paints and inks, and crop protection chemicals.
- Consumer chemicals are sold to final consumers, such as soaps and detergents described above as well as perfumes and cosmetics.

Figure 2.3.3 shows the breakdown of the European chemical industry sales by sectors. Figure 2.3.4 depicts the customers and illustrates how the chemical industry underpins virtually all sectors of the economy and its strategies impacts on society. For instance, the heavy industrial users of chemicals like rubber and plastics makers, construction companies, pulp and paper mills, and the automotive sector all play important roles in our society. They all depend on the base chemicals manufactured by the petrochemicals sector using capital and energy intensive processes, such as thermal cracking, reforming, hydrogenation, distillation as well as polymerization and extrusion (European Commission, (EC) 2018)[2].


EU chemical sales 2017 (€ 542 billion)

Source: Cefic Chemdata International 2018

Unless specified, chemical industry excludes pharmaceuticals
Unless specified, EU refers to EU 28

Figure 2.3.3. : 2017 EU chemical industry sales by sectoral breakdown (source: https://cefic.org/app/uploads/2018/12/Cefic_FactsAnd_Figures_2018_Industrial_BROCHURE_TRADE.pdf)

The Chemical Industry: Provider of Solutions for a Sustainable World

Chemical products contribute to a sustainable society and are key to a growing world requiring more energy, food and water. In fact, they are also crucial for other industrial sectors to reduce their CO_2 emissions. They contribute to low carbon energy technologies and other technological solutions to enhance resource development and energy efficiency. Some examples of these technological solutions to reduce GHG emissions are:

- Renewable electricity production (e.g. wind and solar)
- Energy storage (electrical, thermal, chemical energy storage)
- Energy efficienct buildings (e.g. via using insulation materials, advanced lighting)
- Transport, including electric cars and fuel efficient tires
- Lightweight materials for manufacturing
- Advanced food packaging
- Water purification and water transportation.

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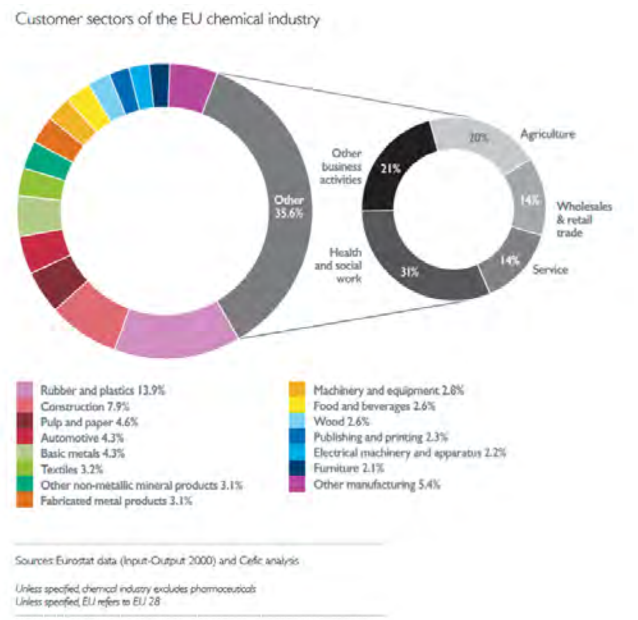
[2] European Commission, 2018. In-depth analysis in support of the Commission Comminication Com (2018) 773. A clean planet for all. A European long-term strategic vision for a prosperous, modern, cometitive and climate neutral economy



Sources: Eurostat data (Input-Output 2000) and Cefic analysis

Unless specified, chemical industry excludes pharmaceuticals
Unless specified, EU refers to EU 28

Figure 2.3.4. Customer sectors of the European chemicals industry

The industry is committed to continue to innovate its product portfolio with advanced materials and technologies (World Business Council for Sustainable Development (WBCSD), 2017). The International Council of Chemical Associations (ICCA), in co-operation with Ecofys, has evaluated the full life cycle impact of several products and solutions from the chemical industry (ICCA, 2017a; 2017b). It assembled 17 robust examples quantifying the impacts enabled by chemical products on greenhouse gas savings.

2.4. The oil refining industry

Energy markets worldwide are dominated by hydrocarbons. As seen in Figure 2.4.1, the main energy source is crude oil.

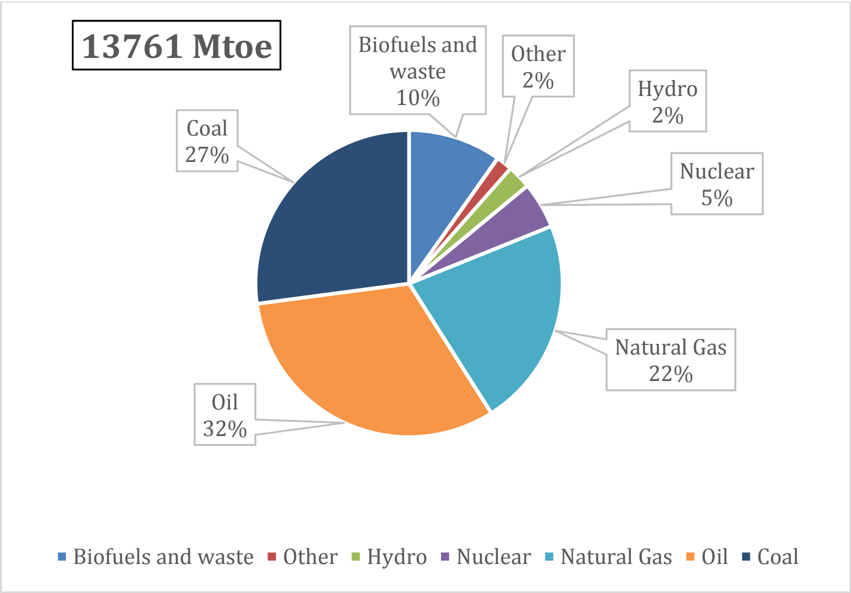


Figure 2.4.1. World fuel shares in 2016, based on data from IEA (2018b)

The oil industry is mainly involved in the following sectors:

- Liquid fuels for transportation, which represent most of the current and future output of the refining industry (mainly diesel and gasoline)
- Petrochemicals are the key driver in the refining industry growth and that will be particularly important in United States and China (IEA, 2018a).

Figure 2.4.2 shows shares of refined products in 2016.

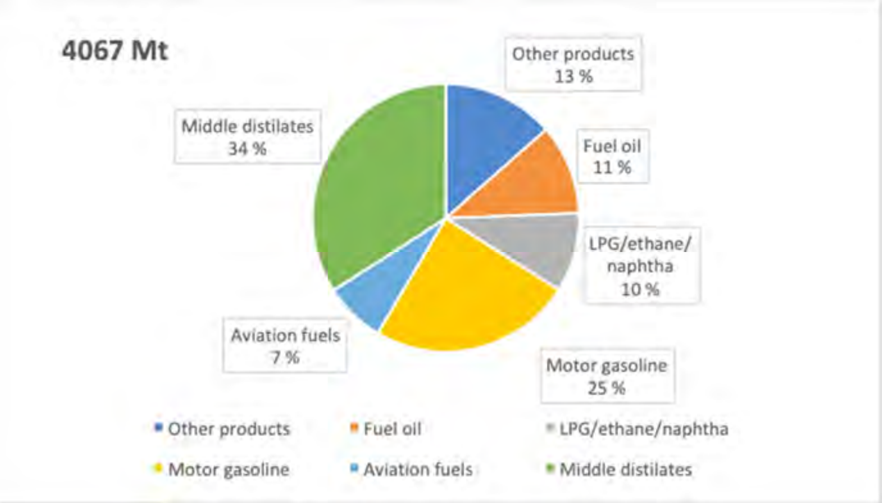


Figure 2.4.2. 2016 shares of refinery by product, based on data from IEA (2018b)

The demand for petroleum products is met via crude oil processing through refineries. The purpose of an oil refinery is therefore to turn crude oil into refined products for end-use, in the quantities that are required by the market.

The refining industry is facing the growing competition of other energy sources for transportation, due to climate change considerations, as for example, the new standards of the International Maritime Organization (IMO) (IEA, 2018a) or electrification.

In 2017, the total oil production was 4,365 Mt, covering the world demand. United States led the production with 12.9%, followed by Saudi Arabia with 12.8% and the Russian Federation with 12.6%. The production increased by 0.6 million b/d in 2017. That was the second year it increased below the 10-year average. The production in the Middle East and South & Central America decreased, but North America and Africa compensated that. The largest increases in production were in USA and Libya, while Saudi Arabia and Venezuela had the biggest reductions, see Figure 2.4.3 (IEA, 2018a). The main exporters were Saudi Arabia, the Russian Federation and Iraq, while the main importers were China, United States and India (IEA, 2018a).

The consumption increased by 1.7 Mb/d, over the 10 year average during the last three years. China was the biggest contributor to this increase (BP 2018), (Figure 2.4.4).

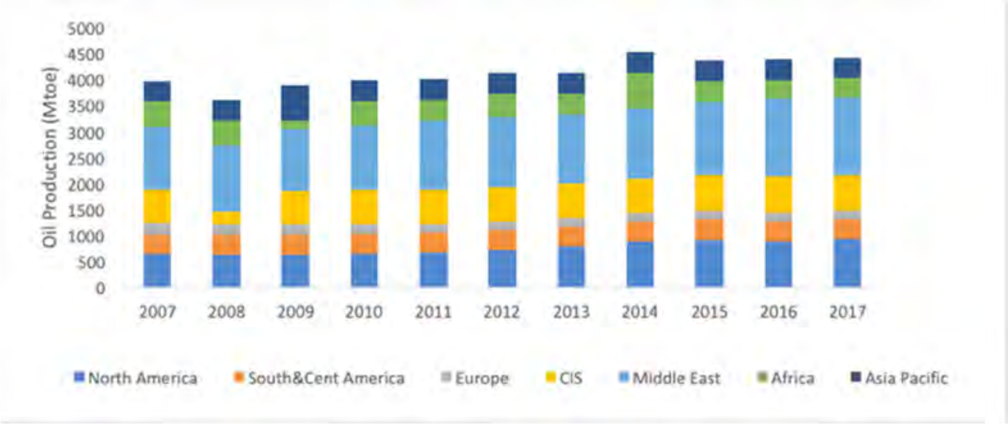


Figure 2.4.3 World oil production by region, evolution from 2007 to 2017, based on data from BP (2018)

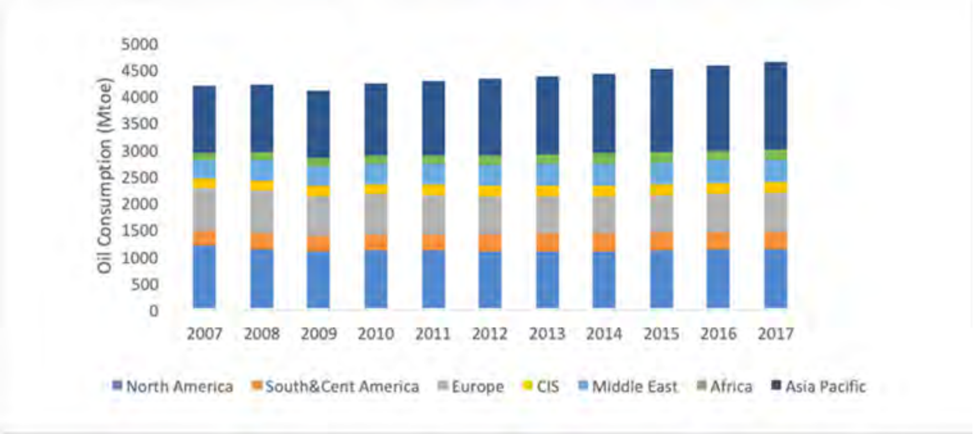


Figure 2.4.4. World oil consumption by region, evolution from 2007 to 2017, based on data from BP (2018)

Refining is spread around the world as a truly global business, and it is strongly linked to the world economy. Consequently, a growth of the global economy will increase the oil demand. IEA (2018a) predicted a solid increase in oil demand, Figure 2.4.5. Based on a global economic growth of 3.9%, the oil demand is expected to grow at an average annual rate of 1.2 mb/d, reaching 104.5 mb/d by 2023. China and India will represent around 50% of the global oil demand. The net supply is also expected to increase. Moreover, the oil demand peak is expected to reach 110 mb/d by 2036 (Wood MacKenzie, 2019), to be followed by a slow decline.

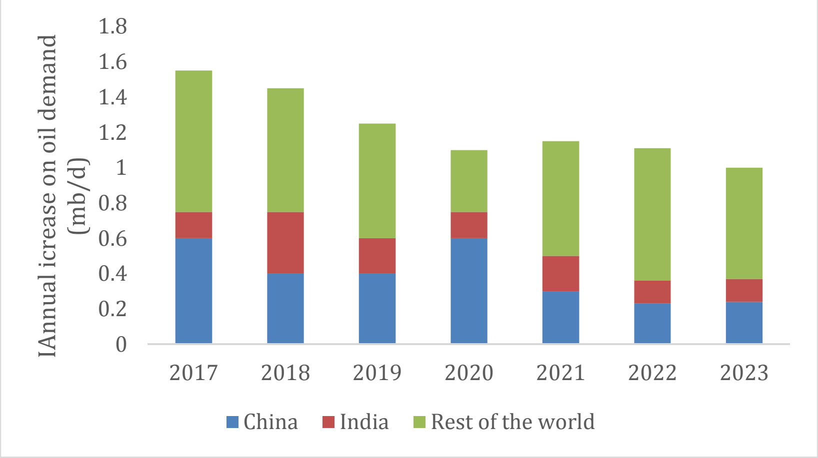


Figure 2.4.5 World oil demand growth, based on data from IEA (2018a)

The increase on the demand of petrochemicals, especially from USA and China, will promote the continuous rise for oil demand over the next decade. Examples include personal care items, food preservatives, fertilisers, furnishings, paints and lubricants for automotive and industrial purposes (IEA 2018a).

In response to oil demand, the refining industry is increasing its capacity. In the period 2018-2023, the net global crude unit capacity will increase by 1.2 Mbd/year. On a longer period, 2010-2025, the average net rate is +0.8 mbd/y with 1.4 mbd expansion and 0.6 Mbd/d capcity closure (Wood Mackenzie, 2019).

2.5. Hydrogen production

Hydrogen is a critical feedstock for the production of clean-burning transportation fuels, fertilizers, and chemicals. Hydrogen holds great promise as a fuel for high efficiency fuel cells for transportation. It can play a role in decarbonizing EIIs, as in the steel industry using direct reduced iron (see Annex A.1). It can serve as back-up power and grid stabilization applications. Hydrogen can also be used to store energy from intermittent renewable sources (e.g., solar and wind). Projected energy storage densities for hydrogen-based systems exceed those of lithium ion batteries, redox flow batteries, and compressed air energy storage.

Globally, around 60 million tonnes of hydrogen were produced in 2015 (Hydrogen Council, 2017). The major producers are China and USA, Figure 2.5.1.

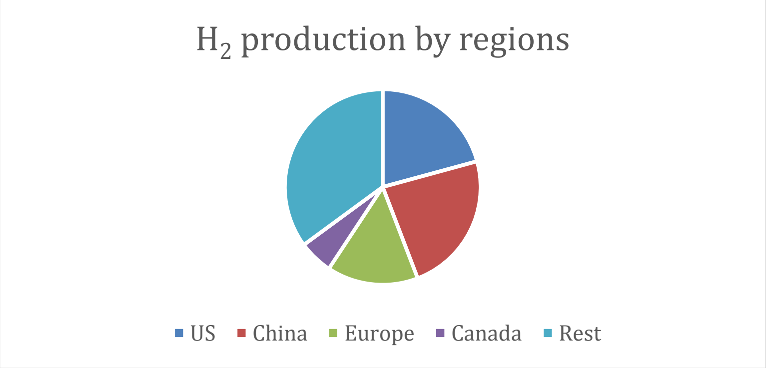


Figure 2.5.1. Global hydrogen production by country and region

Of the 60 million tonnes of hydrogen produced and consumed annually with 53 % used in ammonia (fertilizers), 7 % in methanol production, 20 % in refining, and 20 % for other applications (Essentials Chemical Industry – online, last amended July 2016, Figure 3.4.2 right panel)t. **"**Other**"** includes reducing agents in industry and 500 – 1000 demonstration vehicles (cars and buses).

Hydrogen is produced mainly from fossil fuels and a small percentage by electrolysis of water (see Figure 2.5.2, left panel per several sources including IEA, 2012; Evers, 2008).

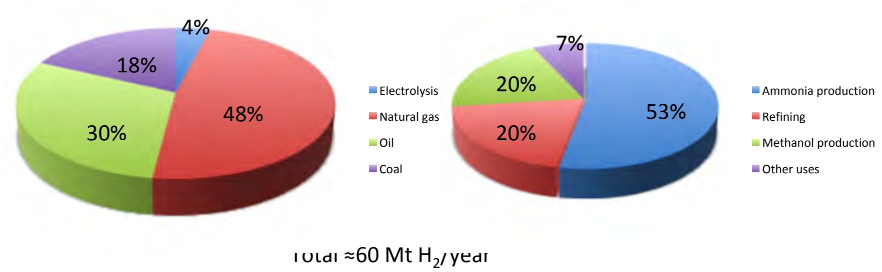


Figure 2.5.2. Global hydrogen production by source (left panel; based on several sources including Evers, 2008) and use (right panel; from Essentials Chemical Industry – online, last amended July 2016).

Several organisations and individuals have tried to make predictions of future uses and applications of hydrogen (e.g. Hydrogen Council, 2017; IEA, 2015; IEA hydrogen, 2017). The applications include:

- Enabling large-scale renewable energy integration and power generation,
- Acting as a buffer to increase energy system resilience,
- Decarbonizing transportation,
- Decarbonizing industrial energy use,
- Helping to decarbonize building heat and power, and
- Providing clean feedstock for industry.

The forecasted demand and production of H_2 in the next years are both high and uncertain. Some forecasts for the period 2017 – 2025 indicate an annual growth rate for the hydrogen market of 5 - 8 % (Grand View Research, 2018; Research and Markets, 2018; Markets and Markets, 2016, 2018). Should the growth rate continue until 2050, the hydrogen production would increase by a factor of 5 – 12, or 275- 650 Mt/year, equivalent to 40 – 92 EJ/year (e.g. the EC, 2006; DNVGL, 2018; the Hydrogen Council, 2017; and the Energy Transition Commission (ETC), 2018).

Figure 2.5.3 illustrates how the demand for hydrogen could increase between 2015 and 2050 (Hydrogen Council, 2017). 78 EJ is equivalent to 550 - 650 Mt H_2, depending on assumed energy density of hydrogen, i.e. a 10-fold increase in demand over the next 30-35 years.

Forecast hydrogen demand 2050 (After Hydrogen Council, 2017)

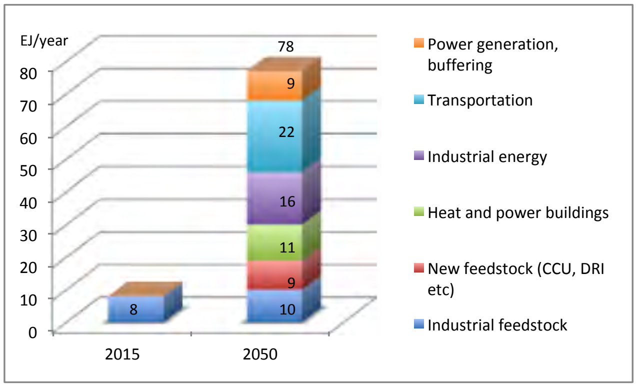


Figure 2.5.3. Possible increase in demand for hydrogen by 2050 (after Hydrogen Council, 2017)

The geographic growth in hydrogen demand is difficult to estimate but presumably shall be equally distributed as it is today (Figure 3.4.1).

Since hydrogen for transportation was in the forefront of the U.S. energy debate a decade ago, there has been substantial progress towards the use of hydrogen as an energy carrier. For example, the estimated cost of hydrogen fuel cells produced in high-volume has decreased by a factor of six (from $275/kW in 2002 to $49/kW in 2011) and a durability in excess of 2,500 hour (or 75,000 miles) has been achieved in vehicle demonstrations. With regard to hydrogen storage, new materials and systems have resulted in an approximately 50% increase in the gravimetric and volumetric capacities since 2007.

2.6. Natural gas (NG) production

Natural gas is an important source of energy. Globally, 22% of energy is provided by natural gas, including 25% for electricity produciton. Besides being an energy source, natural gas is also widely used as a feedstock for many industrial sectors. Natural gas's GHG emissions per unit of heat or power production are lower than the emissions of other fossil fuels, such as coal and petroleum. For example, new natural gas power plants release 50-60% less CO_2 than new coal power plants. Furthermore, natural gas emits significantly less sulphur, mercury, particulates, and nitrogen oxides compared to other fossil fuels. Compared to most renewable energy sources, natural gas provides a more stable and dispatchable supply of energy. In the past decade, natural gas price has also been declining. These factors make natural gas increasingly attractive as an energy source in the future. While natural gas will continue to be used for power and heat generation, it is likely to play an increasingly important role in hydrogen production, fertilizer production and steam generation.

Figure 2.6.1 shows the regional consumption of natural gas consumption in 2016.

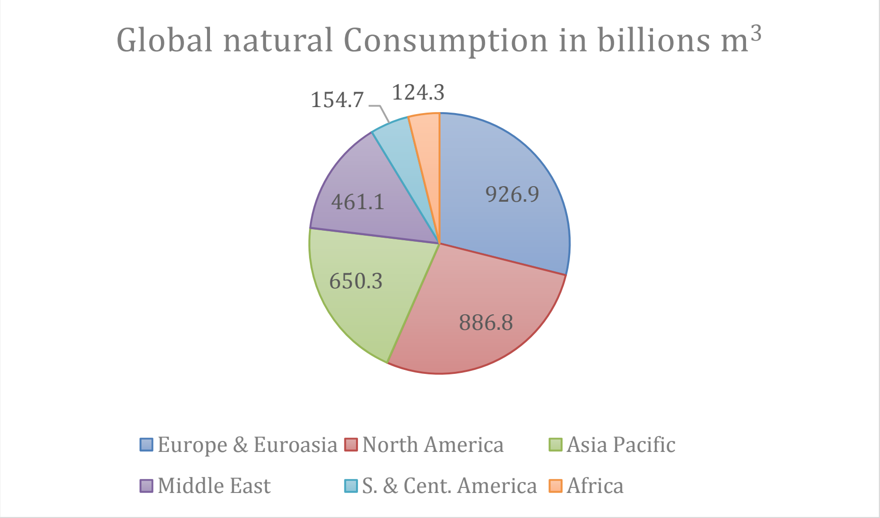


Figure 2.6.1. The regional distribution consumption of natural gas consumption in 2016 (BP, 2017).

Liquefied natural gas (LNG) constitutes an important and growing part in natural gas production, consumption and trade. In 2010, LNG represented 30.5% of the global NG trade. In 2015, about 10% of the natural gas produced globally is liquefied (Canadian Association of Petroleum Producers, CAPP, 2015). The LNG market is expected to grow in global natural gas trade as liquefaction capacity increases.

The global production of natural gas was about 3675 bcm (billion cubic meters) in 2017 and is expected to peak at about 4400 bcm by 2035 and then decline to about 4000 bcm by 2050 (Li, 2018). The highest reserves and production of natural gas are in North America, the Middle East and Russia. Since the beginning of this century, natural gas production increased rapidly in the USA, because of the development of technologies allowing the production from new types of gas fields and this trend is expected to continue to 2050. Table 2.6.1 and Figure 2.6.2 show how the production and its estimated CO_2 emissions were distributed around the world in 2017 and may be distributed in 2050.

Table 2.6.1. Present and future global and regional production of natural gas (Li 2018)

	2017	**2035**	**2050**
World product production (bcm/y)	3675	4570	4026
Production in the main areas in bcm	**Norway: 122** **Russia: 640** **USA & Canada: 897** **Iran, Qatar & S. Arabia: 517** China & Australia: 256 Algeria: 92 Rest of the world: 1151	**Norway: 105** **Russia: 640** **USA & Canada: 1303** **Iran, Qatar & S. Arabia: 1325** China & Australia: 290 Algeria: 93 Rest of the world: 814	**Norway: 43** **Russia: 494** **USA & Canada: 1477** **Iran, Qatar & S. Arabia: 1442** China & Australia: 99 Algeria: 64 Rest of the world: 407
CO_2 emissions (MTPA), based on a CO2 emission rate of 0.11 MT/bcm	415	516	455

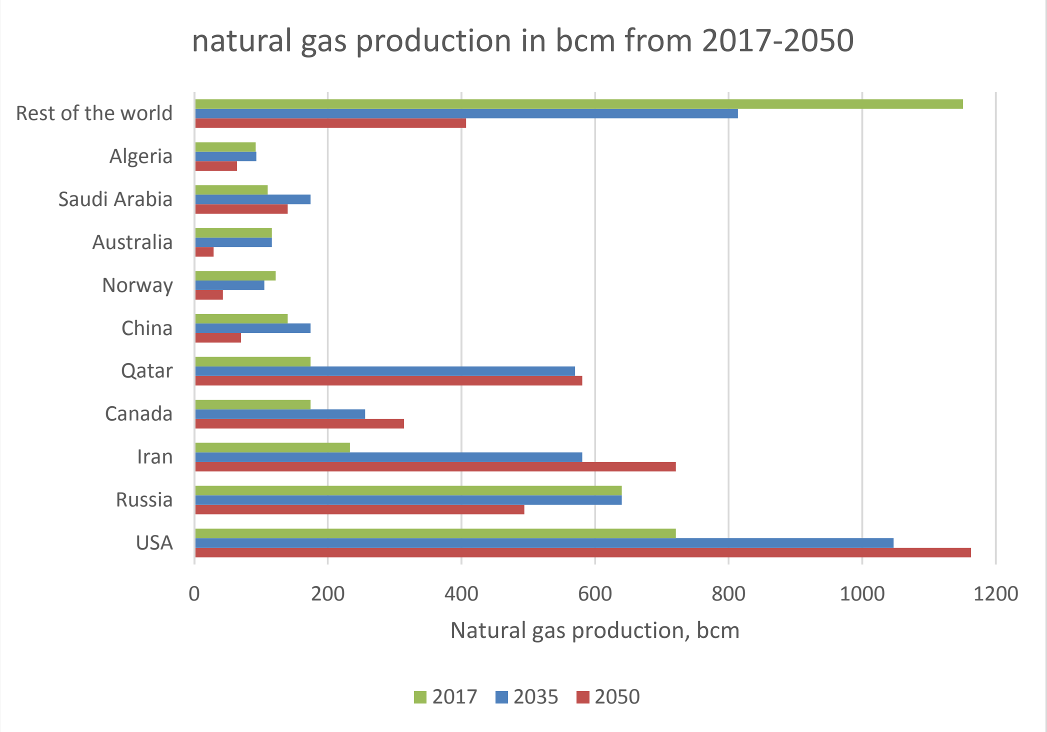


Figure 2.6.2. Geographic distribution of present and future natural gas production

Natural gas exploration and production has evolved tremendously in the past decades. Technological advancements have significantly increased the unconventional gas production, such as coal-bed methane, tight gas and shale gas.

Currently, more and more gas is produced by non-conventional means. A brief summary of these non-conventional gas sources is provided by Al-Megren (2012).

In all scenarios, natural gas's share in the fossil energy mix will increase, even though its share of the global mix will decrease. In absolute quantities, natural gas production might be relatively stable in the future, so it will contribute in its specific ways to climate change mitigation.

2.7. Heavy oil production

Oil exploration and production has evolved tremendously in the past decades with an increasing amount of oil being produced from heavy oil and especially unconventional sources such as oil sands. Figure 2.7.1 shows that over half of the world's known recoverable oil resources and reserves are of the heavy oil types (Meyer et al., 2003).

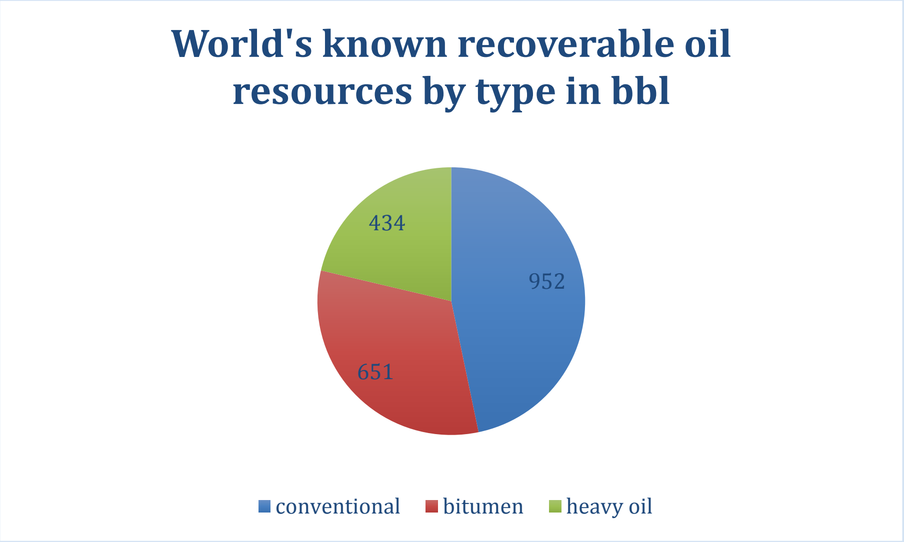


Figure 2.7.1. The world's known recoverable oil resources and reserves

In generalized terms, heavy oil refers to any oil with a viscosity above 100 centipoise. Heavy oil is explored and produced around the world. However, North America and South America are by far the largest heavy oil producers in the world. In North America, heavy oil exists mainly in Canada (the Athabasca Oil Sands in Alberta) as bitumen, which cannot be extracted using conventional technologies. In South America, Venezuela (the Orinoco heavy oil belt) has the most abundant heavy oil reserve that can be tapped with more conventional technologies. Table 2.7.1 shows recoverable heavy oil reserves around the world (Meyer et al., 2003).

Table 2.7.1 – Recoverable heavy oil resources, billions of barrels oil equivalent

	Heavy oil		**Bitumen**	
	Technically recoverable	**Recovery factor**	**Technically recoverable**	**Recovery factor**
North America	35.3	0.19	530.9	0.32
South America	265.7	0.13	0.1	0.09
Africa	7.2	0.18	43	0.1
Middle East	78.2	0.12	0.0	0.10
Asia	29.6	0.14	42.8	0.16
Russia	13.4	0.13	33.7	0.13

Recovery factors were based on published estimates of technically recoverable and in-place oil or bitumen by accumulation. Where unavailable, recovery factors of 10 percent and 5 percent of heavy oil or bitumen in place were assumed for sandstone and carbonate accumulations, respectively.

Recently, due to political and economic issues, heavy oil production in Venezuela has suffered tremendous setbacks. This report will thus focus primarily on heavy oil production in Canada from the Canadian oil sands.

Oil sands consist of extra heavy crude oil or crude bitumen trapped in unconsolidated sandstone. These hydrocarbons are forms of crude oil that are dense and viscous, making extraction difficult. They cannot be produced by conventional methods, transported without heating or dilution with lighter hydrocarbons, or refined by older oil refineries without major modifications. In 2011, Alberta's total proven oil reserves were ~170 billion barrels representing 11 percent of the total global oil reserves. In 2017, Canada and Venezuela produced about 4.3 MMb/d of heavy oil (2.7 MMb/d for Canada, as reported by Natural Resources Canada and 1.6 MMb/d for Venezuela per US Energy Informartion Administration, EIA). This is about 4.6% of global oil production, 92.6 MMb/d in 2017 (BP 2017). Table 2.7.2 shows the expeted development of heavy oil production in Canada.

Table 2.7.2. World heavy oil production

	2017	**2050**
World product production, MMb/d	4.3	Canada: > 5
Production in the main areas (Canada, Venezuela, 2017), MMb/d	Canada: 2.7 (NRCan) Venezuela: 1.6 (EIA)	Canada: > 5 Venezuela: NA

It is suggested that a sustained decline in global conventional oil production appears probable before 2030 (Miller & Sorrell, 2013). Oil sands already make an important contribution to global liquids supply and most forecasts anticipate a significant expansion over the next 20 years. It is projected that oil-sands production will increase by 120% with total growth starting to level off by 2030. Diluted bitumen production is to increase 147% from 2010 to 2050 and synthetic crude by 81% (Evans & Bryant, 2013).

2.8. The fertilizer industry

The fast growing global population needs food. Fertilisers are amongst the most important factors to secure sufficient food production. Fertilisers are plant nutrients that are required for crops to grow, in addition to energy (from sunlight) and water. There are three main nutrients (Yara, 2017):

- Nitrogen (N), the main constituent of proteins, is essential for growth and development in plants. Supply of nitrogen determines a plant’s growth, vigour, colour and yield.
- Phosphorus (P) is vital for adequate root development and helps the plant resist drought Phosphorus is also important for plant growth and development, such as the ripening of seed and fruit.
- Potassium (K) is central to the photosynthesis of crops. Potassium helps improve crop quality and crop resistance to lodging, disease and drought.

Accordingly, one can define fertilisers into three main groups:

- Nitrogen (N)
- Phosphorus (P), expressed as phosphate (P_2O_5)
- Potassium (K), expressed as potash (K_2O).

Fertilisers containing two or more of the nutrients also exist, so called multinutrient fertilisers, e.g. NPK.

In 2014 the global consumption of fertilsers was 186.7 Mt, of which 61% were from nitrogen fertilisers (see Figure 2.8.1).

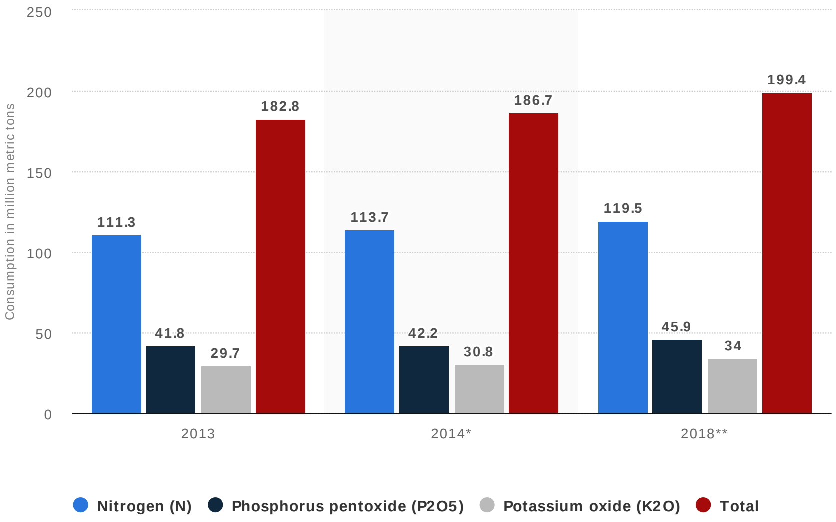
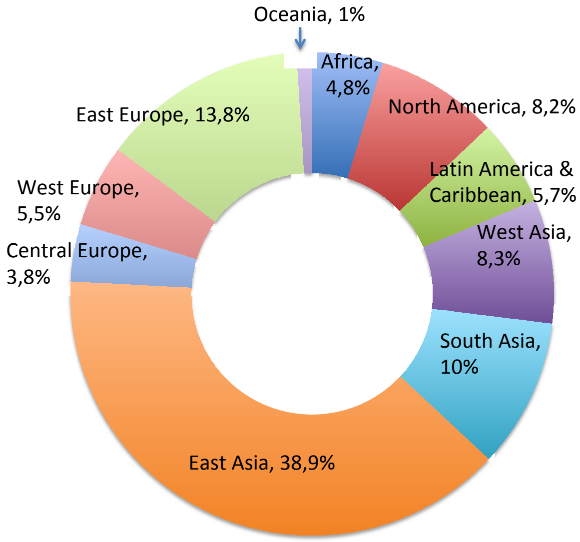


Figure 2.8.1. Global consumption of fertilisers by nutrient (from statista, The Statistical Portal)

Ammonia is one of the most important chemical commodities in the global commodity market. Annual production is increasing steadily to enable increased production of nitrogen fertilizer. Current world production of ammonia is about 170 – 180 million tons per year. Approximately 80% goes to fertilizer, the remaining 20% to plastics, fibers, explosives, amines, amides, glues and other nitrogen containing chemicals (IPCC, 2007). Figure 2.8.2a shows the regional distribution of ammonia production capacity (Food and Agricultre Organisation, FAO, 2017), and Figure 2.8.2b the modelled ammonia production between 2014 and 2060 in the B2DS (IEA, 2017). There are only minor differences between B2DS and the two other scenarios RTS and 2DS. Philibert (2017a) indicates that the global ammonia consupmtion will be 270 Mt/year by 2050.

a)



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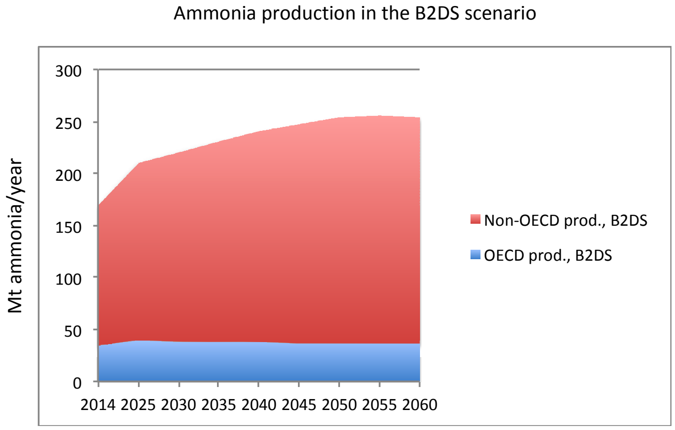

Figure 2.8.2. a) Regional distribution of ammonia production capacity in 2015 (after FAO, 2017) b) Global Ammonia production the B2DS scenario (after IEA, 2017)

In 2014, fertilizer sales amounted to US$ 172 billion (Heffer and Prud'1homme, 2016), of which 49% was for N-fertilisers, 23% for P-fertilisers, 13% for K-fertilisers, and 15% for NPK (International Fertilizers Association, IFA, 2017). The global production revenue, i.e. combined value of fertilisers and raw materials production, was estimated to be US$ 302 billion, with N-fertilisers accounting for more than 50% (IFA, 2017).

It is expected that the global sales of nutrient fertilisers will increase by 1.3%/year towards 2021, with investmenst during the years 2017 – 2021 close to US$ 110 billions in more than 65 new plants. This may increase the annual global production capacity by 90 milion tonnes.

2.9. The waste-to-energy (WtE) industry

Waste is usually classified in four categories according to source. 1) Municipal solid waste (MSW, see Box 2.9.1 for definition, the World Energy Council, WEC, 2016[3]); 2) process waste; 3) medical waste; and 4) agricultural waste. Statistics on total waste generation is uncertain. Reports and papers used in this review focus on MSW, which is used for converting waste to energy (WtE). Thus, this report will deal only with MSW and its conversion into energy.

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[3] Note that that the World Bank (2012, 2018) appear to use somewhat different deinition, by excluding some of the industrial waste, demolition waste and electronics.

In 2017, the annual MSW generation was estimated as 2.01 Gt, with disposal treatment as shown in Figure 2.9.1 (World Bank, 2018). It is noted that 1/3 was classified as “open dumps”, i.e. disposed in an environmentally unsafe way. This is a conservative estimate. 11% or around 0.2 Gt was incinerated. By 2025 the generation of MSW is expected to increase to 2.2. Gt/year (World Bank 2012; WEC, 2016) and to 3.4 Gt by 2050 (World Bank, 2018). MSW accounts for about 5% of global GHG emissions (World Bank, 2012). Landfill is the largest contributor, with significant emissions of methane (CH_4).

The WtE market was estimated to be 25 billion US dollars in 2013, with Europe having the largest share**,** about 48 % of the whole market. The Asia-Pacific market is dominated by Japan, which uses up to 60% of its solid waste for incineration. The global market is expected to grow to US$40 billion by 2023 (WEC, 2016).

Box 2.9.1
Definition of Municipal solid waste (MSW), from WEC (2016)

Residential	Food wastes, paper, cardboard, plastics, textiles, leather, yard wastes, wood, glass, metals, ashes, special wastes (e.g. bulky items, consumer electronics, white goods, batteries, oil, tyres), household hazardous wastes, e-wastes.
Industrial	Housekeeping wastes, packaging, food wastes, wood, steel, concrete, bricks, ashes, hazardous wastes.
Commercial & institutional	Paper, cardboard, plastics, wood, food wastes, glass, metals, special wastes, hazardous wastes, e-wastes.
Construction & demolition	Wood, steel, concrete, soil, bricks, tiles, glass, plastics, insulation, hazardous waste.
Municipal services	Street sweepings, landscape & tree trimmings, sludge, wastes from recreational areas.

The composition of MSW depends on several factors, such as economic development, cultural norms, geographical location, energy sources, and climate. Globally, the major fraction of MSW is of organic origin, followed by paper and plastics. Other contributors can be seen in Figure 2.9.2. In the member countries of the Organisation for Economic Co-operation and Development (OECD), the share of organic material is less (~ 30%) and the share of paper, higher (also ~ 30%). In other parts of the world, the organic part constitutes 50 – 60% of MSW and paper, around 15%.

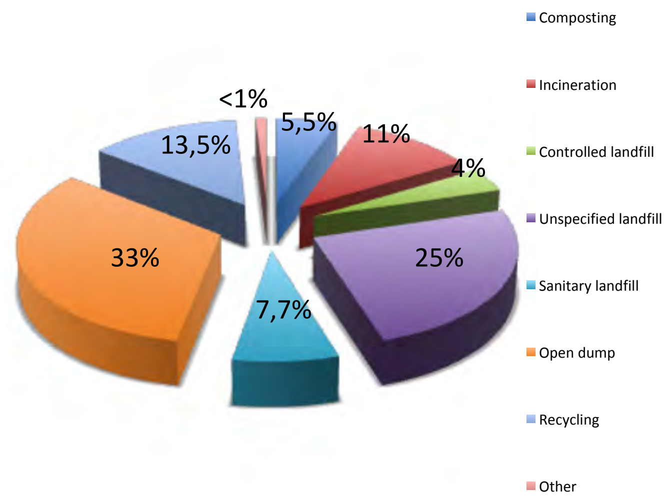

Figure 2.9.1. Global waste treatment disposal, in percent (World Bank, 2018).

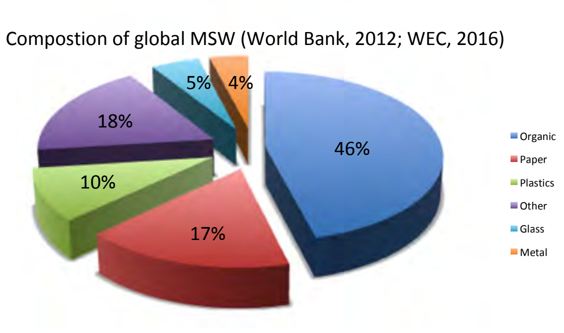

Figure 2.9.2. Global composition of MSW in 2012 (World Bank, 2012; WEC, 2016).

3. Review of EII’s and the role of CCUS on their decarbonisation

3.1. The steel industry

How is the steel production contributing to today’s economies?
Steel is essential in many aspects of the economic activities: infrastructures, renewable energy devices (hydro, wind, solar), power (thermal, nuclear), equipment (machineries), buildings, and consumer goods (cars, machines). Industry represents around 70% of the consumption of steel.

How is the steel production anticipated to contribute to the growth of the economies?
Steel is particularly important in developing and emerging countries where significant amounts of infrastructure will need to be built.

Where are the main geographical locations of steel production? Where is the production growth anticipated to be?
Today China is by far the major producer of steel, followed by Japan and India. 30% of the world steel current production comes from OECD countries (510 Mt/year in 2014), 70% from non-OECD countries (1,160 Mt/year).

The steel production in emerging countries will grow faster than in developed countries due to its rapid progress in development. Moreover, a significant number of qualified jobs and/or high tech investments are associated to this industry.

Steel production in non-OECD countries will increase by 40% until 2050, while only by 10% in OECD countries, so that 75% will come from non-OECD countries in 2050. Overall production will increase by 30%, 2170 Mt in 2050 vs 1670 Mt in 2014 (IEA, 2017).

What are the present and anticipated future of CO_2 emissions by this sector?
The CO_2 emissions from steel and iron production in 2014 were 2.3 Gt. This may be reduced to 1.3 Gt by 2050 in 2DS. There are two main types of production of steel: from ferrous oxide (ore), and from recycling. On average worldwide, 70% of the steel is produced out of ore, and 30% is recycled. Increased use of reccyled steel is expected to contribute significantly to the reduction of CO_2 emissions.

The CO_2 emission patterns depend on production routes, which are region-specific. China will improve its processes of producing steel making, following the path of the developed countries since World War II. In China, this will result in reducing GHG-emissions by 50% through the increase of energy efficiency, recycling of scrap, and use of alternative reductants. This will allow China to increase its steel production by approximately 30% without any new investment.

What are the main sources and patterns of CO_2 emissions of a typical plant for the steel production?
The most extended steel production route is the blast furnace (BF) with a basic oxygen furnace (BOF). The CO_2 emissions are around 1.5 tCO_2/t crude steel (power excluded). The BF is the principal CO_2 emissions source, accounting for 70% of the CO_2 emissions of the whole process, with a concentration of around 22%-vol, while the BOF gas (BOFG) has a concentration of approximately 14%-vol (0.10 t CO_2/t steel). Another important CO_2 emissions source is the sinter plant (0.4 t CO_2/t Steel), but with a much lower CO_2 concentration (5%) and additional CO_2 is emitted in the coke oven (CO) and the combined heat and power (CHP) plant. The most commonly investigated configuration for CO_2 capture, combines few emission stacks and results in a CO_2 concentration of up to 30% (IEAGHG 2018).

The second production route is the electric arc furnace (EAF), which represents 25% of the global share. The CO_2 emissions are indirect emissions, from electricity production, and represent 30-40% of the primary routes. The decarbonization strategies will be directed to the power plant itself and, consequently, power generation related CCUS technologies and parameters are to be considered.

What other ways beside CCUS exist for reducing CO_2 emissions from steel production?
The alternatives to CCUS to cut down emissions in the steel production are:

- Increasing the role of Direct Reduced Iron (DRI) processes and recycling in the global steel production (the emissions factor would be as low as 650 kg CO_2/t steel).
- Implementing new processes that would produce iron using electrolysis reduction systems with renewable electricity.
- Using a low carbon reducing agent (H_2 instead of C for the DRI process): H_2 would have to be produced by carbon free electrolysis or by SMR plus CCS. That route would also result in a large stream of oxygen as byproduct, also useful for the steel industry.
- Use of biomass for both power production and as reducing agent (substituting carbon). Combined with CCS (bio-energy CCS or BECCS) this offers an opportunity for negative CO_2 emissions.
- Creating synergies between steelmaking and other industries will reduce CO and CO_2 emissions, while pushing the dominance of certain chemicals for the production of other products.

However, these alternatives will not fully avoid the CO_2 emissions from the production process.

What is the development status of CCS technologies applicable to the main sources of CO_2 emissions from steel production?
Amine-based chemical absorption is the most advanced CO_2 capture technology. That route can be applied to the flue gas from the BF, as well as from the BOF or the CHP unit. Although other technologies are being tested at smaller scale (for example, STEPWISE project is testing the Sorption Enhanced Water Gas Shift, or SEWGS, technology), those have not achieved the advanced development status of chemical absorption yet. However, further development will continute in the near future. Other options at early development include: oxyfuel, as the Top Gas Recycling Oxygen Blast Furnace (TGROBF) arrangement, total gas recirculation in the oxygen basic furnace, Pressure Swing Adsorption (PSA) or Vacuum Pressure Swing Adsorption (VPSA), membranes, and hybrids (as combination of oxyfuel with chemical absorption or VPSA). These CO_2 capture technologies are being studied for traditional steelmaking configuration (blast furnace with oxygen basic furnace), and advanced configurations such as HiSarna or Hismelt.

For decades, the steel industry has been using DRI with natural gas to capture CO_2 from the reducing gas and re-use a portion of it. This is the case at Emirates Steel in Abu Dhabi as the captured CO_2 is used for EOR purposes. The DRI process at HYL in Monterrey, Mexico, has been in operation since the 1950's, whereas at the ArcelorMittal plant in Lazaro Cardenas, Mexico, CO_2 is removed from the reducing gas by amine-based chemical absorption. Steelmakers have already several pilots with amine scrubbing in service (Voest, Nippon Steel, Thyssen Krupp pilot Carbon2Chem) or in development (ArcelorMittal 3D pilot in France). The footprint of this technology is very low since waste heat of steel making can be used to regenerate the amines and solvents. When there is not enough waste heat available, some of the CO_2 is separated with a PSA as in the Steelanol project of ArcelorMittal. Finally, membrane-based separation is used to scrub relatively high CO_2 concentration from the fumes of steelmaking. This rather impure CO_2 is used for slag and mineral carbonation.

What are the challenges to the implementation of CCS in steel production?
Since steelmaking is a very competitive market, costs are a significant impediment for CCS. The Al Reyeddah project (Abu Dhabi) is benefitting from favorable conditons like inexpensive natural gas and revenue generated from CO_2 EOR.

The economic environment of this industry is very challenging due to production overcapacities. Competitors are worldwide, especially when the extra cost incurred by CCS is significant. Although the technological challenges of CCS are not insurmountable, there is no other large CCS project apart from Al Reyeddah.

The cost impact associated with CCS in the range 60 to 100 Euros/t. As the emissions of CO_2 are around 2tCO_2/tSteel, it means that the cost of production of steel would increase by 120 to 200 Euros/t steel, or + 30% to 50%. However, the impact on the final price of a consumer product could be much smaller. For example, the price of a car would increase by 1-3%.

3.2. The cement industry

How is the cement industry contributing to today's economies?

Cement usage is crucial for buildings, infrastructures, and industrial plants. It is crucial for the transition towards low carbon energy, as in different types of power generation: nuclear, hydropower, wind, and thermal power plants. It plays a significant role in energy efficiency in buildings.

How is the cement industry anticipated to contribute to the growth of the economies?

The strong economic growth of emerging countries will be supported by the growth of the cement sector.

Where are the main geographical origins of the cement industry production? Where will the economic growth come from?

Most of the cement production is and continues to be outside OECD, around 70%. China alone accounts for 52%. Global cement production is set to grow by 12 - 23% by 2050 from the 2014 level. The main increases will be in India and Africa with the 2050 production tripling that of 2014 and the Americas, doubling.

What are the present and anticipated future CO2 emissions of the cement industry?

The global CO_2 emissions from the cement industry were 2.3 Gt in 2014. To meet the 2 degree Celsius Scenario (2DS), a significant reduction of CO_2 emissions from cement manufacturing is required, roughly 24% compared to the current level despite continuingly increasing production. To obtain this, it is estimated that the global direct CO_2 intensity (tCO_2/t cement) will have to decrease by 32 % in 2050, compared to 2014[4].

What is the CO_2 emission pattern from a typical cement plant?

Most of the CO_2 emissions are due to the calcination process in the clinker, approximately 0.53 t CO_2 are emitted for each ton of cement. Two-thirds of the emissions are due to the calcination process: CaCO3 => CaO + CO_2, while the other third is due to the combustion of fuels (coal, petcoke, gas, wastes) for heat requirements. The CO_2 concentration in the flue gas merged from various processes is around 20%.

What other ways than CCUS exist for reducing the CO_2 emissions from cement production?

Many technologies and processes have been developed and are being developed, of which the most important are:

- Improving energy efficiency
- Switching to alternative fuels (fuels that are less carbon intensive), including biomass from waste
- Reducing the clinker to cement ratio,

These measures will result in significant CO_2 emission reductions, e.g. lowering clinker to cement ratio may reduce 37% of CO_2 emissions. Nevertheless, they alone will not be sufficient for the cement industry to achieve the targetted reductions.

What is the development status of CCS technologies applicable to the cement industry?

Cement industries have undertaken various RD&D activities to reduce their carbon footprint by capturing and utilizing CO_2. CO_2 can be separated from the other components of the flue gas via post combustion processes like amine-based chemical absorption. This is being considered for large scale implementation in the Norcem plant (Norway) under a partial capture arrangement, using the Aker solvent. This decision was based on the results from testing this solvent at a smaller scale as compared with other technologies including solid sorbents, membranes and calcium looping.

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[4] Direct CO2 intensity refers to gross direct emissions, after carbon capture (IEA and CSI, 2018)

A number of concrete making plants are currently utilizing CO_2 in the manufacturing process and thus reducing CO_2 emission (e.g. CarbonCure and Solidia) through carbon mineralization (CO_2 utilization). The process starts with the conversion of CO_2 into solid calcium carbonate minerals and transforming CO_2 into a chemical compound permanently bound within the concrete.

Oxy-combustion is also being considered by the European Cement Research Academy (ECRA). Presently only lab tests and front end engineering and design (FEED) studies have been completed. Other examples of development projects for CO_2 capture for the cement industry include CEMCAP (Oxy-combustion, chilled-ammonia CAP), membrane assisted CO_2 liquefaction, calcium looping (CaL) and chemical absorption based on MonoEthanolAmine (MEA), LEILAC (direct separation to be tested at large scale soon) and CLEANKER (CaL to be tested at large scale).

What are the challenges to the implementation of CCS/ CCU in the cement industry?

The impact of CCS/CCU operations on the overall cost of cement production will probably be significant, increasing the cement price by 30-200% depending on the energy/steam production and the integration of the CO_2 capture system with the production facility. However, for example the cost impact on buildings could be much lower, possibly as low as 3% (ETC, 2018).

There is also the question of how to avoid carbon leakage, i.e. ensuring that implementation of CCS/CCU will not impact on the competitiveness of the cement production with CCS/CCU versus cement production without.

3.3. The chemical industry

How is the chemical production contributing to today's economies?
World chemical sales were evaluated at €3.4 trillion in 2016.

Products from the chemical industry are essential to almost all sectors from health, hygiene, construction, transportation, renewable energy supply, and energy storage.

How is the chemical production anticipated to contribute to the growth of economies?
World chemical sales are expected to reach the level of €6.6 trillion by 2030, driven also by the growth in the sectors mentioned above because of growing population and living standards. In addition, the energy transition itself will also spur additional need of products from the chemical industry.

Where are the major geographical origins of the productions of the chemical industry? Where is the production growth anticipated to be?
As highlighted in the table below, the chemical industry is expected to grown in all regions, but the main growth will be in China and the rest of Asia.

Distribution of world chemical sales in 2016 and projected figures for 2030. Source: Cefic ChemData International.
(https://cefic.org/app/uploads/2018/12/Cefic_FactsAnd_Figures_2018_Industrial_BROCHURE_TRADE.pdf)

	Distribution of sales (€3.4 trillion) in 2017 (€billion)	**Distribution of sales (€6.3 trillion) in 2030 (€billion)**
EU	542,1	709
Rest of EU	111,7	178
Canada, Mexico and USA	518,9	910
Latin America	108,5	268
China	1.293,2	3.302
Japan	154,0	212
Rest of Asia	699,2	975
Rest of the World	47,8	66

What are the present and anticipated future CO_2 emissions of the sector?
The cumulative CO_2 emissions from production of chemicals and petrochemicals were around 1 Gt CO_2/year in 2014 (IEA, 2017) with the biggest contributor from ammonia production (covered in this report under the Fertilizers section). The petrochemical industry is a complex and heterogeneous industry from products, processes to feedstock used to manufacture the base materials. Worldwide the manufacture of 18 products (among thousands) from the chemical industry account for 80% of energy demand in the chemical industry and 75% of greenhouse gas (GHG) emissions. Emissions from the sector will be highly influenced by technology development and deployment of production routes with lower emissions including the integration of alternative energy sources and alternative carbon sources.

What are the main sources and patterns of CO_2 emissions of the chemical industry?
Considering the diversity of chemical products, processes and feedstock, there is no standard emission pattern for the chemical industry. Emissions include a variety of CO_2 sources from diluted streams of natural gas combustion processes (10%) to highly concentrated streams (close to 100%). The majority of the emissions in the chemical industry fall in the former category (i.e. lower concentration).

What other ways exist for reducing the CO_2 emissions from the chemical industry?
Improved energy management, higher conversion efficiency of chemical production processes and fuel shift have been the major options initially considered for the reduction of GHG emissions. In Europe, the total GHG emissions in the EU chemical industry, including pharmaceuticals, decreased by 60.5% from 1990 until 2015 while at the same time the production expanded by 85%.

Additional key priorities for further reduction of GHG emissions in the chemical sectors are based on the development of alternative processes for:

- Utilisation of low carbon energy sources, including direct and indirect utilisation of renewable electricity, alternative energy forms, H_2 with low carbon footprint.
- Better utilisation of alternative carbon sources (contributing also to the development of a circular economy):
    - Biomass including biogeneous waste streams,
    - CO and CO from industrial sources (with or without low-carbon H_2), and
    - Waste (including plastic recycling).

In addition, digital technologies are expected to support decision-making from the design phase of new production processes and plants to optimize resource and energy utilisation, and minimize GHG emissions through implementation of the above mentioned technologies.

The DECHEMA study on “Low carbon energy and feedstock for the European chemical industry” issued in 2017 looked at the production of the main chemical building blocks used in upstream large volume production processes that collectively represent two-thirds of the European chemical industry’s current GHG emissions. According to the “ambitious scenario” developed in this study, the implementation of the technologies investigated could lead to a CO□ abatement of 101 Mt/y by 2050, a reduction of CO_2 emissions of 84% vs. “Business as Usual Emissions” in 2050.

Materials produced by the chemical industry may play a crucial role to reduce CO_2 emissions in other sectors, leading to a growing sustainable society requiring more energy, food and water. Some examples of improvements are:

- Increases in resource and energy efficiency in other sectors, such as construction, transport, packaging and water management, and
- Development of low carbon energy technologies to advance sustainable production of renewable electricity and energy storage, as well as advanced materials and process technologies for the production of alternative sustainable fuels.

What is the development status of CCU technologies applicable to the main sources of CO_2 emissions from the chemical industry?

New processes are being developed to utilise CO_2 (with or without H_2) as a feedstock to produce chemicals and polymers. A commercial plant to capture and purify CO_2 from the Ethylene Glycol process is operational in Jubail, Saudi Arabia. The captured CO_2 is used to produce methanol and urea. Demonstration plants already exist for the production of methanol from CO_2 with renewable H_2 and CO_2-based polyols. The chemical industry is uniquely positioned to accelerate the utilization of CO_2 and turn CO_2 into valuable products. While the amount of CO_2 captured and used in this way might have limited impact on climate change directly, the potential impact of such technologies can be very high and be applicable to the CO_2 emissions from various EIIs. The technological advances will help the capture and purification technologies to mature, and thus driving improvements for the capture and purification processes for the CO2 streams from other EIIs as well.

What are the challenges to the implementation of CCS in the chemical industry?

The development of technologies limiting CO_2 emissions has been prioritized.

The lower concentrated CO_2 streams (which represent most of the emissions), and multiple independent stacks emitting CO_2 on chemical sites are majors barriers to the implementation of CCS. In addition, the location of production of chemicals has been optimized based on various criteria, but the potential for CO_2 sequestration has not been considered. Consequently, in most cases the emission source is very distant from a potential location for sequestration. In addition, CO_2 sequestration includes an additional cost with no value creation. Lack of infrastructure, cost of capturing and cost of sequestration are limiting the deployment of CCS.

For process related CO_2 emissions, the technology developments for the utilisation of CO_2 as alternative feedstock, which offers the potential of value creation have been prioritized versus sequestration.

3.4. The oil refining industry

How is the refining production contributing to today's economies?

Crude oil production today represents 33% of the global energy mix with refined oil products accounting for 94% of the transportation mix and 80% of the feedstocks of the chemical industry. Crude oil is the most actively traded and watched commodity in the world. Refined products such as gasoline and diesel are actively traded (Canadian Fuels Association 2013), and other markets such as bitumen, lubricants and solvents are linked to the refining sector.

How is the refining industry anticipated to contribute to the growth of economies?

The market demand for refinery products depends on the dynamics of the global economy. Issues such as population growth, the size of working-age population, urbanization levels and immigration all play important roles in shaping the energy market. Global population is expected to increase from around 7.6 billion in 2017 to 9.2 billion by 2040. The majority of this growth will come from developing countries, particularly from Africa, India and the Middle East.

The future demand of oil may very well depend on a variety of petrochemical products and not necessarily on fuels for automobiles. Thanks to decarbonization goals and new regulations, alternative production routes for petrochemicals are emerging. With a stronger demand for electric cars and progress on fuel efficiency, the production growth for automobile fuels may slow down (IEA, 2018b).

Where are the major geographical locations of refinery productions? Where is the production growth anticipated to be?

Refining is spread around the world and is truly a global business. The share of Europe and Eurasia (Russia excluded) has decreased from 17.7% in 2015 to 17.3% in 2016 but remains the third largest refining region. Asia Pacific has the largest capacity at 33.7%, followed by North America at 22.7%.

Petrochemicals will drive the oil demand growth, especially in the United States and China. The demand will grow at an average annual rate of 1.2 MMb/d and by 2023, the oil demand will reach 104.7 MMb/d (IEA, 2018a). Although the International Maritime Organization (IMO) regulation on sulphur content might impact on the contributions of each fuel type, the total oil demand will not be affected because the high-sulphur heavy fuel oil will have to find new markets (power sector for example).

By 2023, China and India together are expected to contribute to nearly 50% of the global oil demand. That would be followed by the Middle East with a 20% of the share. However, China is expected to slow down in their demand due to stronger emission and efficiency regulations and increased use of electric and natural gas vehicles (IEA, 2018a).

The levels of oil production in different regions are changing. The production from China, Mexico and Venezuela has fallen down in the past three years. The net growth in the total OPEC production will be 750 kb/d by 2023, assuming stability in Iraq, Libya and Nigeria. Non-OPEC countries, led by the US, are driving the oil production, growing to 3.7 mb/d, more than half of global production capacity (6.4 mb/d)[5]. This increase in growth includes the contributions from Brazil, Canada and Norway (IEA, 2018a).

What are the present and anticipated future CO_2 emissions of the sector?

On average, the energy consumption from a refinery is 0.4 GJ/bbl, 70% being auto-produced and 30% imported energy (Solomon, 2016). In Europe, direct emissions from refineries equal to 209 kg CO_2/tcrude (Concawe internal data, 2017 average).

CO_2 emissions from refineries account for approximately 4% of the global CO_2 emissions, nearly 1 billion tons of CO_2 per year in 2005[6] (van Straelen et al. 2009).

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[5] Those numbers could be even higher if prices rise above assumptions made in IEA (2018a)

[6] Data from the IPCC report published in 2005, emissions from transportation not included

A refinery could use 5.5-7.5% of feed as fuel, depending on its complexity (IEAGHG, 2017). For a 300,000 barrel per day refinery, that would mean approximately 3-4 million tons of CO_2 per year (van Straelen et al. 2009). The emissions strongly depend on the refinery configuration dictated by market demands and product specifications. Generally, more complexity will lead to higher emissions. The expected growth in petrochemicals production as noted before will increase the CO_2 emissions from the refining industry. However, the increase can be mitigated by the promotion of greener production routes to reach climate change agreements to 2050.

What are the main sources and patterns of CO_2 emissions of a typical refinery?
In a typical complex refinery, the main emission sources come from power generation, 24% of total at 4-8 vol% concentration; fluid catalytic cracking (FCC), 13% of total at 17 vol% concentration; steam methane reformer (SMR), 12% of total at 24 vol% concentration; and two distillation units, 20% of total at 11 vol% concentration (IEAGHG, 2017).

What other ways than CCUS exist for reducing the CO_2 emissions from the refining industry?
CO_2 emissions can be reduced through a number of routes (Choudhari, undated):

- Process modifications
- Energy conservation
- Modify fuel quality (low C/H fuels, hydrotreatment of fuel components)
- Use of carbon free electricity for power and steam production
- Use of alternative end products will reduce the production and cut down the CO_2 emissions associated to those applications (e.g. in transport and petrochemicals)
- The use of low carbon hydrogen, produced through either renewable electricity or natural gas with CCS, could be a means to reduce the emissions of the refining sector.

However, the refinery still will consume considerable amount of energy (van Straelen et al. 2009) and CO_2 capture is the only solution to cut down process emissions.

What is the development status of CCS technologies applicable to the main sources of CO_2 emissions from refining production?
If the challenge of refinery site complexity and the multiple distributed vents most refineries have could be overcome then it is possible that around 90% of the CO_2 produced could be captured more cost effectively, as the refining industry is already familiar with the use of separation technologies (UK Department of Business, Energy and Industrial Strategy, BEIS, 2018). The most recommended configuration is to collect the CO_2 emissions in a combined stack, amongst a number of competitive options (van Straelen et al. 2009). The complexity of implementing CO_2 capture in refineries is not only the number of sources of CO_2 but also the sulphur content, which requires individual or combined desulphurization units. The most advanced technology is chemical absorption, as seen in several projects in Canada and USA, where the business cases are supported by the revenue from EOR and chemicals sales (BEIS, 2018). Moreover, several testing campaigns have been carried out at the Technology Centre Mongstad (TCM), Norway, on flue gases from power production and the FCC. Refineries do not have a significant amount of waste heat available for optimization of the chemical absorption capture process. Therefore, systems and technologies not requiring steam could be advantageous. Oxy-firing in the burners or the catalytic cracker, and gasifier with pre-combustion capture could have some potential (van Straelen et al. 2009), but they are currently at lower development stage.

What are the challenges to implementing CCS in refining production?
Due to the globally competitive nature of the refinery product market and the low profit margins of the refining sector absorbing the cost of CCS effectively is challenging (BEIS, 2018).

3.5. Hydrogen production

Hydrogen is commonly used in the chemical industry, in particular for the production of ammonia and methanol, and for petroleum-refining. It is treated as a separate topic in this report because of its present and anticipated importance. Therefore, emission related to hydrogen production are considered indepentently from other EIIs.

How is the hydrogen production contributing to today's economies?
Today, 53% of hydrogen produced in the world (around 60 Mt) is used for the production of fertilizers. Other significant demands are from refining for desulfurization and upgrading, chemical industry and methanol production. Hydrogen is mostly produced from fossil energy sources (natural gas 48%; oil 30%; coal 18%) and water electrolysis (4%).

How is hydrogen production anticipated to contribute to the growth of the economies?
Hydrogen may become a central pillar of the energy transformation required to limit global warming to two degrees Celsius. It may offer economically viable and socially beneficial solutions.

The potential new use of hydrogen (produced from carbon-free sources) could be:

- Power generation, buffering to increase energy system resilience,
- Decarbonizing transportation,
- Decarbonizing industrial energy use,
- Helping to decarbonize building heat and power,
- Providing clean feedstock for industry.

Where are the main geographical origins of hydrogen production? Where is the production growth anticipated to be?
Today production of hydrogen is approximately 60 Mt H_2 per year. The main producers of hydrogen today are China (13 Mt/year) and the United States of America (11 Mt/year).

The forcasted demand and production of H_2 in the future are likely high but there is some uncertainty. The predictions are in the range of 275 – 650 Mt H_2/year. The geographic growth in hydrogen demand is difficult to estimate.

What are the present and anticipated future CO_2 emissions of the sector?
Emissions from today's hydrogen production of 60 Mt H_2/year are about 500 Mt CO_2/year, with an assumed CO_2 intensity of 8.5 kg CO_2/kg H_2. If the same fraction of hydrogen will be produced by SMR as in 2015 for future demand of 300 – 650 Mt H_2/year, this will result in CO_2 emissions in the range of 2.5 – 5.0 Gt/year.

What are the main sources and patterns of CO_2 emissions of a typical hydrogen production plant?
The most typical route is SMR of natural gas. The emissions are around 8.5 t CO_2/t H_2 (between 7.2 and 8.8 typically). The concentration of the combined SMR process flue gas will be around 19% CO_2.

Other routes for hydrogen production from fossil fuels are Partial Oxidation (POX) and Auto Thermal Reforming (ATR). In these processes, 90% or more of the CO_2 emissions are from the process gas, compared to 70% for the SMR. This is beneficial to CO_2 capture. POX, mainly used for coal, and ATR are known technologies but need further development to be competitive with SMR. Large-scale H_2 production favors ATR. If the cost of O_2 can be reduced, then ATR can become more favorable.
H_2 production from coal results in nearly twice the emission intensity than from natural gas.

What other ways than CCUS exist for reducing the CO_2 emissions from hydrogen production?
Producing H_2 by electrolysis is an alternative. Hydrogen production with this approach will reduce the CO_2 emissions only if the electricity is low-carbon sources. If the power is produced using fossil energy

without CCS implementation, the CO_2 emissions from electrolysis will be higher than using reforming and CCS. In addition, the electricity price needs to be lower than current electricity prices.

If electrolysis is performed with low carbon power, one has to consider the amount of power needed for the ambitious production predictions for 2050 (about 10-fold in the next 35 years). This translates to 330 – 550 Mt H_2 being produced by electrolysis requiring 15 000 - 26 000 TWh. With present world production of electricity being 24 000 TWH, the necessary increase of carbon-free electricity for the anticipated demand of hydrogen will be phenonmenal. It should be noted that carbon-free or low-carbon electrolysis has not yet been implemented at a significant scale due to economic challenges.

Using biomass as feedstock and/or fuel for the reformer may be a low-carbon option even without CCS provided the biomass is grown and harvested sustainably. Combining biomass with CCS will lead to negative emissions.

In any case, the anticipated growth in hydrogen production should include a mix of different approaches including SMR (or ATR or POX) *with CCUS* as well as electrolysis.

What is the development status of CCS technologies applicable to the main sources of CO_2 emissions from hydrogen production?

Most of H_2 is produced today via SMR and CO_2 is routinely removed from the process gas in ammonia production using technologies such as chemical and physical absorption and adsorption. Examples include: Air Products' Port Arthur CO_2 EOR project where ~ 1 Mt CO_2/year from an SMR H_2 plant is captured for EOR purpose, the Tomakomai Project in Japan that captures 200 kt CO_2/year from a SMR H_2 plant using activated amine, and the Air Liquide Port Jérôme Project in France where 100 kt CO_2/year of food-grade CO_2 is captured from an SMR H_2 plant.

However, there are other gas streams, such as reformer flue gas, where CO_2 capture can be implemented. Pressure swing adsorption technologies are used for H_2 and CO_2 separation. In some cases, solvent based absorption processes are used with chemical solvents (hot potassium carbonate also known as Benfield process, and amine based solvents) or physical solvents (Selexol or Rectisol) for CO_2 capture. Membrane based separation technologies are also getting more attention in recent years for H_2 purification and CO_2 capture. Ion Transport membranes (ITM) that operate at high temperature are promising since they combine air separation and methane partial oxidation into a single unit operation, resulting in significant cost savings (>30%, compared to conventional ATR and ASU).

What are the challenges to the implementation of CCS in hydrogen production?

One impact of CCS on hydrogen production will be an increase in hydrogen prices by 25 -50%. Even with a price increase, SMR with CCUS may still be competitive with water electrolysis, depending on the prices of natural gas, low-carbon electricity and CO_2.

3.6. Natural gas production

How is the natural gas production industry contributing to today's economies?

Natural gas is an important source of energy. Globally, 22% of energy is provided by natural gas, including 25% for electricity generation.[7] It is also widely used as a feedstock for many industrial sectors (e.g. hydrogen and ammonia production).

How will the natural gas production industry contribute to the growth of the economies?

Natural gas's GHG emissions per unit of heat or power generation are significantly lower than the emissions of other fossil fuels. Fuel switching from coal to natural gas will play a significant role on decreasing CO_2 emissions and will explain the increasing share of natural gas in the fossil energy mix in the future.

The use of hydrogen as feedstocks for products in petrochemicals contributes to natural gas production growth because hydrogen is mainly produced from SMR as stated in the last section. This increasingly important role in hydrogen production together with its relevance to fertilizer production and steam generation, underlies its importance to many industrial applications.

Where are the main geographical origins of the natural gas production industry? Where will the natural gas production growth come from?

Global annual LNG production capacity stood at 340 MT in 2017, with 879 Mt/year new LNG proposals pending.[8] If all the proposed LNG capacity is realized, global LNG production would be at 1219 Mt/year by 2050. For a more modest growth rate of 2% per year, the global LNG capacity would be about 620 Mt/year by 2050.

The highest reserves and production of natural gas are in North America, the Middle East and Russia. Since the beginning of this century, natural gas production has been increasing rapidly in the USA from 2000 to 2017, owing to the development of new technologies allowing the production from tight gas fields. LNG production has also increased in other countries (Australia, Russia), which are now significant new exporters of liquefied natural gas like the USA. It is projected that by mid 2020s, the USA could become the top LNG exporting nation.

Future natural gas production growth is expected to come mainly from North America, especially the US, and the Middle East. Other regions, such as Russia and Europe, are expected to see a decrease in natural gas production. The production of natural gas is expected to peak at about 4500 bcm (billion cubic meters) by 2035 from 3675 bcm in 2017 and then decline to about 4000 bcm by 2050.

What are the present and anticipated future CO_2 emissions scenarios of the natural gas production industry?

The development of LNG industry will result in an increase of CO_2 emissions per unit of consumption. CO_2 emissions from an LNG plant is around 5.24 g CO_2/MJ, while from a conventional plant without liquefaction, around 1.72 g CO_2/MJ, depending on the gas reservoir.

The present annual LNG production of 340 Mt results in estimated emissions of 98.5 Mt CO_2/year. An increase in capacity of LNG production to 620 Mt/year or 12919 Mt/year would translate to CO_2 emissions of 180 Mt/year and 353 Mt/year respectively; if no CCS technology is implemented.

Native CO_2 emissions will be more difficult to estimate since it is dependent on the CO_2 content of the gas field being mined (from 2% to >70% that has to be cleaned).

One factor for a likely increase in CO_2 emissions from natural gas production is that its growth will rely on certain geographic regions where the native CO_2 concentration in the natural gas is high. A good

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[7] IEA, https://www.iea.org/topics/naturalgas/

[8] IGU 2017 World LNG report, International Gas Union.

evidence of that is that some new operations involve natural gas fields with relatively high CO_2 concentrations, for example the Gorgon Field in Australia.

What is the CO_2 emission pattern of a typical plant in the natural gas production industry?

In an LNG plant, total CO_2 emissions will be around 5.57 g CO_2/MJ, assuming that CO_2 in the produced natural gas has been removed. For a typical 10 Mt/year LNG plant, the CO_2 emissions, excluding native CO_2, are about 2.9 Mt/year. Most of the emissions come from large point points like fuel combustion to produce electrical or mechanical energy (average 5.24 g CO_2/MJ) and flaring. Typical CO_2 concentrations in these streams are around 3% v/v. These streams are more amenable for capture, where most of the current CCS projects in operation are targeting. Another 0.33 g CO_2/MJ is emitted from scattered sources where capture is difficult.

In case natural gas is exported for direct use, CO_2 will have to be removed from the gas if the content exceeds the sales specification. This is accomplished through gas processing to produce a stream of highly concentrated CO_2 amenable for capture and storage. In this case, the overall CO_2 emissions will be significantly lower, on the average ~1.72 g CO_2/MJ, but highly dependent on the CO_2 content in the gas reservoir, compared to 5.24 g CO_2/MJ in the case of LNG, notwithstanding any CO_2 from the raw natural gas.

What other ways than CCUS exist for reducing the CO_2 emissions from natural gas production?

For natural gas production, there are few non-CCS solutions available to reduce CO_2 emissions, except for removal of the native CO_2. It is possible to reduce the CO_2 emissions due to fossil fuel combustion for other operations through electrification if carbon free electricity is available. CO_2 emissions can also be reduced by improving efficiencies of turbomachinery and process integration.

For LNG operation with optimised heat and power balance, CO_2 emissions from fuel consumption can be reduced by approximately 30%, leading to CO_2 emissions from fuel in the range of 3.1 to 4.1 g CO_2/MJ (0.17 to 0.22 t CO_2/t LNG).

These measures will be insufficient to achieve the necessary reductions of CO_2 emissions from natural gas production.

What is the development status of the technologies applicable to the main emissions for the natural gas production industry?

Solvent absorption is a mature technology to separate natural gas from its native CO_2 and is widely used. Presently, there are a number of significant CCUS projects based on the capture of native CO_2 from the raw natural gas. These include Sleipner and Snohvit (Europe), Terrell natural gas processing plant, Shute Creek gas processing facility, and Century Plant (USA), In Salah (Algeria), and soon Gorgon (Australia). In the case of Gorgon, this project will be the biggest worldwide with 3 to 4 Mt/year CO_2 captured from CO_2 separated from the natural gas.

For CO_2 emitted from turbomachines in LNG plants, one can anticipate that it could benefit from the implementation in other sectors of post-combustion CO_2 capture technologies as well as oxy-fuel combustion technologies.

What are the challenges to the implementation of CCS in the natural gas industry?

Technology is mature to remove CO_2 from raw natural gas. These technologies can be deployed without incurring significant cost to the natural gas production because, in many cases, CO_2 must be removed from the raw gas to meet the requirements for transportation and sale. As a result, the additional costs associated with CCS are limited to compressing, transporting and storing the CO_2. For example, the \$100 million CCS operation was just 2.5% of the overall \$4 billion cost of the In Salah gas production complex. That puts the cost of sequestering the CO2 at about \$14/ton (Massachusetts Intsititue of Technology (MIT) Technology Review (2008).

For LNG production, the CO_2 concentration in the exhaust gas is low (~3-4%), which makes application of established CO_2 removal technologies, such as amine scrubbing, costly to deploy. It is estimated that a 10% efficiency penalty is incurred with the post-combustion CO_2 capture technology for LNG production, and that the CO_2 avoided costs vary from US$ 60-180/tonne CO_2.

3.7. Heavy oil production

How is the heavy oil production industry contributing to today's economies?

In 2017, two major heavy oil-producing countries, Canada and Venezuela produced about 4.3 MMb/d of heavy oil (2.7 MMb/d for Canada, as reported by Natural Resources Canada and 1.6 MMb/d for Venezuela). This is about 4.6% of global oil production (92.6 MMb/d in 2017). Petroleum is not only used as an energy source for transportation, but also for heating, electricity generation. It is also used to produce asphalt and road oil, as well as a feedstock for producing chemicals, plastics and synthetic materials.

How will the heavy oil production industry contribute to the growth of the economies?

Heavy oil production will continue to grow as the world population grows along with the rising global standard of living. For example, oil sands production in Canada is expected to double. In the meantime, conventional oil production is expected to plateau or decline over the next decades, making heavy oil increasingly important.

Where are the main geographical origins of the heavy oil production industry? Where will the production growth come from?

Heavy oil is mainly produced in Canada and Venezuela. However, the production in Venezuela has declined due to many factors. Thus, Canada is currently the main producer of heavy oil. The heavy oil production in Canada would increase from the current 2.7 MMb/d to over 5 MMb/d. It is expected that heavy oil production in Venezuela will rebound in the future.

What are the present and anticipated future CO_2 emissions of the heavy oil production industry?

In the case of Canadian oil sands industry, in a business as usual scenario, GHG emissions are expected to rise from the current 62 Mt CO_{2e} /year to 120 Mt CO_{2e} /year by 2050 with a peak of 130 Mt/year CO_{2e} at 2031.

What is the CO_2 emission pattern of a typical plant of the heavy oil production industry?

GHG emissions variy significantly, depending on the extraction technologies. Surface mining has a GHG emission intensity of ~40 kg CO_{2e}/bbl. In comparison, the global volume-weighted carbon intensity is ~60 kg CO_{2e}/bbl (Reference: Global carbon intensity of crude oil production, Science, vol. 361, issue 6405, 31 August 2018). For surface mining, it is very difficult to capture CO_2 associated with the mining activities due to the disparate sources of CO_2 emissions. In-situ processes typically result in higher emission intensity (~65-80 kg CO_{2e}/bbl). For both processes, CO_2 associated with the production of hydrogen, hot water and steam has significant impact on emissions intensity of any of the individual processes used to produce oil-sands products. This source of CO_2 is also quite amenable for CCS purposes.

What other ways than CCUS exist for reducing the CO_2 emissions from heavy oil production?

Most of the CO_2 emissions are due to mining and requirements for thermal energy and hydrogen. Currently, steam methane reforming is the chosen technology for hydrogen production. To reduce GHG emissions, alternative technologies with CCS have been proposed. For example, biomass gasification can be used for hydrogen production.

Bitumen extraction process can be electrified. A pilot project based on electric heating for bitumen extraction is in operation in Alberta, Canada. This option obviously requires carbon-free electricity generation, which can be met with renewable energy sources, such as wind and solar.

For in-situ extraction, the focus is on decreasing steam requirement. Ongoing efficiency improvements and the penetration of new hybrid steam-solvent technologies that partially substitute solvents for steam could reduce steam use—and thus energy and GHG intensity - of in-situ production by 5% to 20% (well-to-tank basis).

Nuclear reactor is another option to produce carbon-free steam. Toshiba Corporation has developed a small nuclear reactor to power oil sands extraction in Alberta that could be operational by 2020.

These measures will be insufficient to achieve the necessary reductions of CO_2 emissions from heavy oil production.

What is the development status of the technologies applicable to the main emissions for the heavy oil production industry?

Heavy oil production requires a significant amount of hydrogen, steam and hot water. Reducing the requirement for these products and improving the energy efficiencies to produce these products will lead to lower GHG emissions. As well, CO_2 capture technologies in producing hydrogen, steam and hot water are being implemted. Oil sands operators have been testing CCS technologies in Alberta, Canada. Shell's Quest CCS project has been successfully capturing and storing up to 1.2 Mt/year of CO_2 from its hydrogen production units and Enhance Energy Inc.'s Alberta Carbon Trunk Line (ACTL) will transport and store 1.6-1.8 Mt/year of CO_2 for EOR purposes. In the case if ACTL, CO_2 will be captured within the gasification hydrogen supply unit, which will use unconverted asphaltene as feedstock to create syngas with the rectisol acid gas removal technology. In western Canada underground coal gasification for hydrogen production with CCS has also been studied as a viable pathway.

For thermal energy requirement, which is by far the most GHG intensive step in heavy oil production, technologies such as chemical looping combustion are currently being developed to address this challenge.

What are the impediments to the implementation of CCS in the heavy oil production industry?

CCS technologies are difficult to implement for oil sands industry because CO_2 streams are relatively small and diluted. Oil sands facilities are also scattered over a vast area and would require additional infrastructure and operating costs to implement CCS technologies. However, these challenges have not deterred the oil sands operators to invest in R&D projects to capture CO_2 from relatively concentrated sources such as those from hydrogen production units and steam production units.

3.8. The fertilizer industry

How is the fertilizer industry contributing to today's economies?
Agriculture is the main outlet of fertilizer industries. Intermediate products like ammonia and nitric acid are also used in different industrial applications. Examples are ammonia as source of nitrogen for polyamides/nylons, technical ammonium nitrate for mining explosives, and urea and ammonia in NO_x control in automobiles and industry. The fertilizer industry employs more than 900 000 people, and has a turn over of around US$ 170 billion.

How is the fertilizer industry anticipated to contribute to the growth of the economies?
The future production of fertilizers will depend mainly on the evolution of demography, standard of living and consumption habits (meat versus vegetables for proteins).

Where are the main geographical origins of the fertilizer industry? Where is the production growth anticipated to be?
Today, the production of ammonia is arond 180 Mt/year and it is expected to grow to 220- 230 Mt/year over the next few decades. South, west and east Asia are the regions with the highest production of ammonia, followed by Eastern Europe and Central Asia. The top three countries for N fertilizer consumption are China (31% of global consumption), India (15%) and the United States of America (11%). The strongest growth in consumption over the next few years is expected to be in South and East Asia and the Latin America and the Caribbean. The demand for N by industrial users is growing faster than that by fertilizer companies.

What are the present and anticipated future CO_2 emissions of the sector?
Present CO_2 emissions are approximately 400 Mt/year. With expected growth over the next few decades, the emissions will rise to around 550 Mt CO_2/year, or more, by 2050.

What are the main sources and patterns of CO_2 emission of a typical fertilizer plant?
The most used process to produce hydrogen for fertiliiser production is SMR, an endothermic process in which natural gas (methane) reacts with steam to produce hydrogen and process CO_2 under high temperature. Heat is provided by burning fuel in a furnace, producing fuel CO_2. Of the CO_2 emission from SMR, 70% is process CO_2 (pure) and 30% is fuel CO_2 (around 10% concentration). When coals or heavy hydrocarbons are used, then the CO_2 emitted per ton of ammonia or fertilizer is higher. Process CO_2 is much less costly (50%) to capture and compress than fuel CO_2, because of the much higher CO_2 concentration.

What other ways than CCUS exist for reducing the CO_2 emissions from fertilizer production?
Competitive ammonia production without CO_2 emissions can be envisaged from water electrolysers, but probably not before 2030. In the short term, more efficient SMR process, or using ATR or POX in new plants, will still need CCS to provide the needed reductions.

What is the development status of CCS technologies applicable to the main emissions for the fertilizer industry?
The primary technologies for taking out CO_2 from fertilizer production are based on chemical absorption and are well known and mature, as CO_2 is routinely removed from the ammonia process gas. Two fertilizers plants in USA (Enid, Oklahoma, and Coffeyville, Kansas) collect the CO_2 and export it for enhanced oil recovery (EOR). Furthermore, nitrous oxide from nitric acid can removed by well-established and mature catalyst technologies (Yara and BASF technology).

Removal of CO_2 from the primary reformer exhaust gas can be done by known technologies, such as amine scrubbing, CAP, and others, but this has not been applied to a significant extent so far.

Other technologies for hydrogen production for fertilisers are POX (most common for liquids like oil), ATR (a combination of non-catalytic POX and SMR), and gasification (used for solid fuels like oil and biomass). In these technologies, more than 90% of the CO_2 emissions come from the process gas, making CO_2 capture simpler and cheaper than for SMR. On the other hand, these technologies are more expensive but improvements may change this.

What are the challenges to the implementation of CCS in the fertilizer industry?

The technologies may exist but costs are significant: up to 210 $/ton CO_2 was estimated to capture CO_2 from the reformer gas for a first-of-a-kind Norwegian plant.

The impact of CCS on product prices has not been investigated. Ammonia competes in a global market and is highly sensitive to uneven regulatory and taxation regimes. Implementing CCS in European ammonia production plants may put them in a difficult situation when the ammonia is exported to the Asian and American markets.

3.9. The waste-to-energy (WtE) industry

How is the Waste to Energy industry contributing to today's economies?

Municipal Solid Waste (MSW) generation was 2.0 Gt in 2017, of which about 1/3 was not collected. Of the collected MSW, 60 – 65 % is sent to landfills and composting, 20 % is recycled and 17 % is used in energy recovery facilities (130 tonnes in 2012).

The energy output from WtE may be applied to electricity generation, heat production, combined heat and power, and in the case of gasification and pyrolysis, to transport fuel production. For example, 74 WtE plants in the United States generated around 14 TWh electricity in 2014.

How is the Waste to Energy industry anticipated to contribute to the growth of today's economies?

WTE is unlikely to take a significant share of the energy and transport fuel markets, but its development will help tackle around 5% of the current GHG emissions worldwide (CO_2 equivalent).

Where are the main geographical origins the Waste to Energy industry? Where is the growth anticipated to be?

Japan, Europe, USA and China are by far the biggest WtE producers (considering the number of plants: Japan: 1200, Europe: 500, USA: 460, China: 200 to 450, rest of the World: 40 to 50).

China and the Asia-Pacific region will have the fastest growth in WtE applications until 2025.

What are the present and anticipated future CO_2 emissions of the sector?

Today, considering that around 11% of the 2 Gt/year of MSW is converted to energy, or 220 Mt/year, and that in a modern incineration plant, emissions are around 1t CO2/tMSW (gross emission, no credit for biomass content), the global CO_2 emissions from WtE are around 0.2 $GtCO_2$/year.

The generation of MSW is anticipated to grow to 2.2 Gt by 2025 and to 4 Gt by 2100. One might expect that the share being converted to energy (11%) will increase over the next decades, depending on national and local policies. Thus, future emissions from conversion of MSW to energy are difficult estimate. By 2050, this may be 0.3 $GtCO_2$/year (assuming linear increase in generated MSW 2025 – 2100).

What are the main sources and patterns of CO_2 emission of a typical Waste to Energy plant?

A modern plant that incinerates 0.4 Mt MSW/year, will emit between 0.4 and 0.5 Mt/year of CO_2. If there is a coal power plant closeby, the flue gas of the incinerator can be piped to merge with the power plant exhaust to have only one flue stack.

Since much of the waste is from organic sources (fraction depends on location), the development of CCS on WtE projects is considered as BECCA and will result in negative CO_2 emissions, which are deemed necessity to achieve the goals of the Paris Accord.

What other ways than CCUS exist for reducing the CO_2 emissions from the Waste to Energy industry?

Ideally, only residual waste goes to WtE. Therefore, sorting and recycling should not be presented as an alternative to reduce GHG emissions from WtE. CCS will be the best solution.

What is the development status of the technologies applicable to the main sources of CO_2 emissions from the Waste to Energy industry?

Carbon capture technologies are similar to those of coal power generation and the technical viability of carbon capture technologies in WtE environments has been proven. Carbon capture at a WTE plant has already been demonstrated in the city of Saga, Japan, by Toshiba, with chemical absorption capturing 10 tonnes CO_2/day. The CO_2 is being used in the pharmaceutical and nutrition industries. The technology is adapted from the power sector. In the Netherlands, AVR will start the construction of a MEA capture facility at its WtE plant in Duiven. The CO_2 will be used for horticulture in greenhouses.

In Norway, the capture of the emissions of the Klemetsrud WtE plant have been studied with two technologies: proprietary amines and CAP.

What are the challenges to the implementation of CCS in the Waste to Energy industry?

Costs are probably the most significant impediment, although CO_2 utilisation can complement CCS, as in the Japanese demonstration plant, thereby reducing the cost. Optimal use of waste heat for the capture process in combination with district heating could also contribute to the business case.

4. Summary of status and gaps in CCUS technologies for industry

The deployment of CCUS is deemed plausible in short/medium term to meet future global climate change goals for the industrial sector. The emissions from industries, either process related or inherent in feed stock, are quite diverse amongst different EIIs. Diverse gas compositions, including impurities, often make it hard to find a single CO_2 capture process that fits well to various industries. Each application may require a custom capture solution suitable to its industrial sectors. There are significant knowledge gaps in technology selection and in moving technologies to higher TRL levels for industrial uptake and deployment. Different industries are currently engaged in performing techno-economic analysis and RD&D activities to investigate and develop the feasible technology options for CO_2 capture to address industrial needs. Many of these technologies are at an early stage of development. A few examples of the CO_2 mitigation efforts and progress made to date by several industrial sectors are presented here.

The steel Industry:
There are several steel production routes and each has different CO_2 stacks. The blast furnace based route is most common and carbon intensive. New production routes, energy efficiency and carbon free electricity can reduce CO_2 emissions. Perhaps, process emissions can be tackled completely only through CO_2 capture. The capture approaches considered for the steel industry are mainly chemical absorption, oxy-firing and sorbent-based technologies such as VPSA (vapour pressure swing absorption), applied to capture the CO_2 from the blast furnace or from the combination of several CO_2 stacks. Hybrid technologies are also under research. The Al Reyadah project in Abu Dabhi includes a large chemical absorption system in the steel mill at the Mussafah plant. Oxyfiring and VPSA technologies have been tested at pilot scale and other technologies are under research. For instance, the SEWGS (sorption enhanced water-gas shift) technology is to be demonstrated at a scale of 14 t/day CO_2 removal, under the STEPWISE project funded by the EU's Horizon 2020 research and innovation programme.

The cement Industry:
The cement industry has undertaken various RD&D activities to reduce their carbon footprint by capturing and utilizing CO_2 as well as implementing measures along the value chain. The capture technologies considered for the cement industry are mainly post combustion, oxyfuel, CaL and direct separation. However, membranes, CAP, and indirect calcination are also being investigated. Examples include Norcem (Norway) and the European Cement Research Academy (ECRA, Italy and Austria). Several funded projects have investigated a number of technologies and configurations using modelling and at pilot scale, as in the CEMCAP, CLEANKER, CO2STCAP and LEILAC. The cement and concrete industries are also currently utilizing CO_2 in the manufacturing process and thus reducing CO_2 emission (e.g. CarbonCure Canada and Solidia) through carbon mineralization (CO_2 utilization).

The chemical Industry:
The chemical sector is a very diverse sector with several processing routes and products. However, there are few key intermediate products, which form the building blocks for most of the chemical products. These can be broadly categorised into organic and inorganic intermediate products. Olefins (ethylene is of particular importance), aromatics and methanol are the key organic intermediates whereas; ammonia, carbon black, soda ash, chlorine and sodium hydroxide are the important inorganic chemicals. Many of the industries in the chemical sector have CO_2 generation in the intermediate stages, requiring separation from the process streams. Solvent based processes are mostly in use for capturing these process related CO_2. However, compression and adsorption based technologies are also in use in some cases, e.g. Jubail United Petrochemical Company in Saudi Arabia.

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The oil refining industry
Refineries are intensive CO_2 producers and each of them varies in complexity and configuration. CO_2 is emitted in several points along the refining process, where the power plant/CHP, distillation, catalytic

reformer and hydrogen production units are the most carbon intensive ones. CO_2 emissions can be mitigated through process improvements, fuel switching, and carbon free electricity. However, those measures will not be enough to reach the decarbonized scenarios. Carbon capture could cut down process emissions, which cannot be avoided otherwise. Two refiners (Sturgeon Refinery and Shell Quest project) in Canada are using chemical absorption capture processes to capture CO_2 for utilization and storage. Several pilot tests have been carried out in the TCM (Norway), using the fluegas from a refinery nearby, while Lake Charles Methanol (USA) and the Teeside Collective (UK) are planned large projects.

Hydrogen production

In the hydrogen industry, CO_2 is mainly separated as part of the process. However, there are other gas streams, such as reformer flue gas, where CO_2 capture can be implemented. Pressure swing adsorption technologies are used for H_2 and CO_2 separation. In some cases, solvent-based absorption processes are implemented utilizing chemical solvents (hot potassium carbonate known as the Benfield process, and amine based solvents) or physical solvents (Selexol or Rectisol) for CO_2 capture. Membrane based separation technologies are also getting more attention in recent years for H_2 purification and CO_2 capture.

Natural gas production

Many natural gas reservoirs contain small volumes of various impurities including $CO_{2,}$ which can still be used as fuel, but with high volumes of CO_2, it cannot be burned efficiently and safely. An example of this type is the natural gas produced at the Sleipner Field in the North Sea. Sleipner is an industrial project in which CCS was implemented as part of a gas field development as the gas in the reservoir contained about 9% CO_2, needing significant reduction to less than 2.5% to reach commercial specification (Statoil, 2017). Solvent based CO_2 capture processes, specifically amine based, are most widely used and effective in separating CO_2 from the natural gas streams with low concentration of CO_2. Other technologies such as pressure swing adsorption and temperature swing adsorption as well as cryogenic CO_2 removal can also be used for NG purification and CO_2 capture.

Heavy oil production

CO_2 capture in the heavy oil industry is increasingly becoming important to make the fuel cleaner. Normally large quantities of steam are required for heavy oil extraction where most of the steam is generated through once-through steam generators (OTSG) using natural gas. However, the flue gas from these OTSGs contains significant quantities of CO_2, vented to the atmosphere. Currently there is no commercial plant available for CO_2 capture from the OTSG flue gas. However, solvent or adsorbent-based capture processes will be most suitable for this low pressure and low concentration CO_2 flue gas mixture. A recent pilot demonstration using structured adsorbents to capture CO_2 from OTSG of a steam- assisted gravity drainage (SAGD) project will make it world's first pilot-scale plant. The compact VeloxoTherm^{TM} process developed by "Inventys" will be used for this CO_2 capture.

The fertilizer industry

CO_2 used in urea production in general comes from the CO_2 generated during the production of ammonia. Carbon capture is already happening in ammonia/nitrogen fertilizer plant plants as part of the process gas purification. However, for the reformer gas there is opportunity to capture CO_2. In SMR based ammonia production, about 70% of the CO_2 is generated in the process gas, and 30% in the reformer flue gas. The reformer flue gas composition resembles somewhat the gas composition from a gas-fired power plant, with a slightly higher CO2 concentration. The solvent based CO_2 capture technologies, such as amine will be a suitable option, and since ammonia is available at an ammonia plant, CAP technology (General Electric Alstom) might as well be an option for CO_2 capture.

The waste-to energy (WtE) industry

There are some initiatives also in place with respect to CO_2 capture in the waste-to-energy (WtE) industry. In Norway, two different absorption based capture technologies have been evaluated for CO_2 capture from flue gas generated by waste incineration at the Klemetsrud plant: Aker Solutions' technology based on a proprietary amine, and General Electric's (GE) CAP technology based on chilled ammonia. Both technologies have completed successful test programmes at TCM and in other pilot plant. There was a separate initiative from Toshiba Corporation to capture CO_2 from municipal waste incineration process, in Saga Japan. An alkaline aqueous amine solution was used for the CO_2 capture.

5. Interactions between EIIs, including CO_2 utilisation

The EIIs highlighted in this report share some common issues that can generate synergies. These common issues include the following:

- Most technologies to capture CO_2 are applicable to tackle the emission sources from several types of EII.
- All the capture processes will have substantial capital expendiure (CAPEX) and energy demand. In some cases, the energy can come from process waste heat, like low pressure steam to regenerate the sorbents.
- Steel, cement and chemicals are amongst the EIIs that can use hydrogen or biomass in their production rather than fossil fuels. Process gas from steel and chemicals can have process H_2 in their gasses (e.g. coke oven gas, tail gas from steam crackers).
- The need for infrastructure for transport and storage of the CO_2. The industries, except the oil and gas producers, lack experience in pipeline transport and geological storage of CO_2.

These common issues can pave the way to generate synergies amongst EIIs:

- Since many CCUS technologies can be adapted to different industrial sectors, it is essential that these sectors join forces to develop these technologies. This will greatly reduce the R&D costs for each Isector and reduce the CAPEX and operational expenses (OPEX) of CCUS, including capture technologies and handling CO_2 streams that differ in composition.
- Significant cost reductions can be achieved if clusters of EIIs go together to establish infrastructure to share waste heat utilization opportunities, and also to transport and store CO_2, e.g. pipeline networks, ship transport of CO_2 and storage hubs.
- Some Energy Intensive Industries will play important roles in the decarbonisation of other industries. Here are a few examples:
  - Low carbon hydrogen production is anticipated to decarbonise the steel industry by replacing fossil hydrocarbon for the reduction of ferrous oxide, and to decarbonise some energy demanding industries like cement and ethylene production by burning hydrogen instead of fossil fuels for heat requirement. In addition, low carbon hydrogen will also contribute to CO_2 emissions reduction in heavy duty truck transport and power generation. Using low carbon hydrogen to convert CO_2 to useful products will be an important component of CO_2 utilisation. The demand for low carbon hydrogen can be partially met by hydrocarbon reforming with CCUS.
  - The chemical industry will be an important stakeholder in CO_2 conversion by using the captured carbon to produce a range of products, such as methanol, synthetic fuels and urea. The use of CO_2 will result in emissions reductions if the captured CO_2 if this replaces new, fresh hydrocarbons as a feedstock. Further, the energy used to convert the used carbon into the fuel or feedstock, should be lower than the emission of processing the fossil source. The total carbon footprint, including energy requirements for various CO_2 conversion processes, must be assessed and documented in a full life cycle analysis.
  - The cement industry offers opportunities for CO_2 utilisation:
    - CCUS - Mineral carbonation - Mineralization is the chemical process where magnesium and calcium silicates react with CO_2 to form inert carbonates which can be used as construction materials. Both natural alkaline minerals (widely available) and industrial wastes and by-products such as fly ash with high lime content, cement kiln dust, blast furnace slag can be used. Mineralization provides long-term CO_2 storage. The technology is still in the R&D phase and it is unknown if there is any large-scale adsorption unit to capture CO_2 from flue gases.
    - CCU - Cements based carbonation of calcium silicates. The carbonation of Ca-/Mg-silicates can be considered as a possible CO_2 sequestration process, First industrial trials to produce such cements (e.g. Solidia Cement) have been conducted. This non-hydraulic cement is used for Solidia Concrete, which is

        composed of the same raw materials and can be processed as ordinary Portland cement concrete.

  - The oil and gas industry will provide solutions for transport, storage and utilisation of CO_2:
    - It will bring its unique operational expertise to store CO_2 in geological sites or use it for Enhanced Oil Recovery.
    - It will bring its expertise for CO_2 transport via pipelines or shipping.
    - It will be the provider of natural gas for hydrogen production with CCS.

Synergies between Energy Intensive Industries are already implemented today:
CO_2 is a commodity today that is traded in a global market. It is used in the chemical industry as feedstock, e.g. for urea, in the food industry for carbonation of drinks and in packaging; the oil industry for enhanced oil recovery; and in fire extinguishers. The utilisation of CO_2 opens for further interactions between EIIs, when CO_2 generated from one industry is transfered to another for CO_2 use. Some examples are:

- The steel and chemical industries – The steel industry has launched large research programs, together with institutions, universities and IP-partners in the chemical industry, to re-use carbon emissions for fuels and chemical feedstock. Leaders in this are ArcelorMittal and Thyssen Krupp Steel.
  Their programs are targeting to produce:
  - Ethanol by fermentation and catalytic conversion. The CO_2 abatement potential identified is 8.7 t/t (2.1 t/t by re-use and 6.7 t/t by capture for storage),
  - Methanol, synthetic naphtha by catalytic conversion. The CO_2 abatement potential identified is 10 t/t (3 t/t by re-use and 7 t/t by capture for storage),
  - Acetone, polyurethane. Up to 20% of the fossil polyol can be replaced by CO_2,
  - Ammonia and urea as fertilizers,
  - Propanol, butanol and isobutene as chemical feedstock,
  - Synthetic diesel, Dimethyl Ether (DME) and Oxymethyl ether as fuels,
  - Caproïc and caprylic acid, hydroxiproprionic acid as feed and food.

  The project CORESYM (2017) is a joint steel and chemicals industry project. Although focussing on re-use of carbon monoxide, this is a good example of co-operation between EIIs on the re-use of off gases that will reduce the carbon footprint.
- The technology of a UK company CCm that aims to produce various fertilizers while capturing CO_2 from flue gases and stores CO_2 in a mineral form (https://ccmtechnologies.co.uk/). CCm focus on switching current carbon intensive industrial production and transport systems to low carbon alternatives. Currently CCm carries this out through resource optimisation, avoiding the production of large volumes of ammonia, phosphates and carbon dioxide in the fertiliser industry that require high input of fossil based production methods. CCm’s power generation technology also provides an alternative fuel switch solution to replace diesel and oil based power sources. CCm is also developing a power generation technology that converts waste heat into electricity. This is carried out by taking advantage of waste heat and the varying states of carbon dioxide, for application in industrial sectors. This is an interaction between the fertilizer industry and a number of industries mentioned above, turning CO_2 into $CaCO_3$ while making fertilizers. In this way, CO_2 is permanently sequestered while fertilizers are produced.

6. References

All references in the report are listed in this section. There are separate lists for the EIIs described in chapters 2 and 3 as well as the annexes. In addition, there are separate lists for chapters 1 and 5, and a common list for chapters 4, 10 and 11.

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ANNEX – The main characteristics of CCUS for the chosen EIIs

A.1. The steel industry

A.1.1. Present and future CO_2 emissions from steel production

The iron & steel industry is amongst the biggest industrial emitters of CO_2. It is estimated that the industry emitted 2338 Mt CO_2 from the process itself (direct emissions) in 2014. The future emission numbers vary according to source. Here we have used numbers from IEA (2017), as these are based on scenario modelling and consistent through all industries. In the 2DS the CO_2 emissions are expected to come down to 1306 Mt CO_2/year by 2050, compared to almost 3300 Mt CO2/year in the RTS. An important factor for the reduction in 2DS is increased recycling of steel.

The steel industry is energy intensive, with an average energy intensity of about 21 GJ per tonne of steel (IEA, 2017).

A.1.2. What are the sources of CO_2 emissions from the steel industry?

For steelmaking, there are several routes. Good descriptions, also including approaches to reducing CO_2 emissions, can be found in, amongst others, Carpenter (2012), ISO (2016), Eurofer (2013), GSSCI (2016), Birat and Maizières-lès-Metz (2010), and IEAGHG (2013).

The primary integrated steel plant/blast furnace route

Globally, the predominant route to produce steel, with a share of approximately 70% (IEA, 2017; ClimateTechWiki (http://www.climatetechwiki.org/technology/jiqweb-spis); Birat and Maizières-lès-Metz, 2010). A typical integrated steelmaking plant consists of a coke oven (CO), a sinter or a pellets plant, a blast furnace (BF) and a basic oxygen furnace (BOF). The blast furnace is fed with iron ore, coke from a raw material preparation section and preheated air to produce pig iron (hot metal). The pig iron is then refined in a basic oxygen furnace to obtain the crude steel. Following the steel making are the refining parts casting, rolling and finishing. The process is shown schematically in Figure A.1.1, with contributions to the overall plant CO_2 emissions expressed as tonnes CO_2 emitted /per tonne produced steel (Birat and Maizières-lès-Metz, 2010, IEAGHG, 2013).

CO_2 emissions in an integrated steel mill come from multiple sources, and the allocation of the direct emissions among the various facilities within the mill is very site specific, depending on how the process gases are used. Most plants of this type will have an on-site power plant that generates electricity and steam. Such an installation will use gaseous fuels that are released from the other units such as coke oven gas, BF gas and BOF gas. In some cases this will be sufficient to power the steel mill, in others, fossil fuels (coal, oil or natural gas) may have to be added. Alternatively to figure A.1.1, the emissions from these facilities could be included in the emissions from the power plant. Thus, the numbers in Figure A.1.1 are only indicative.

Earlier an open-hearth furnace (OHF) was used instead of BOF but the technology, which has higher energy requirements and CO_2 emissions, has been shut down in most countries (IEAGHG, 2013).

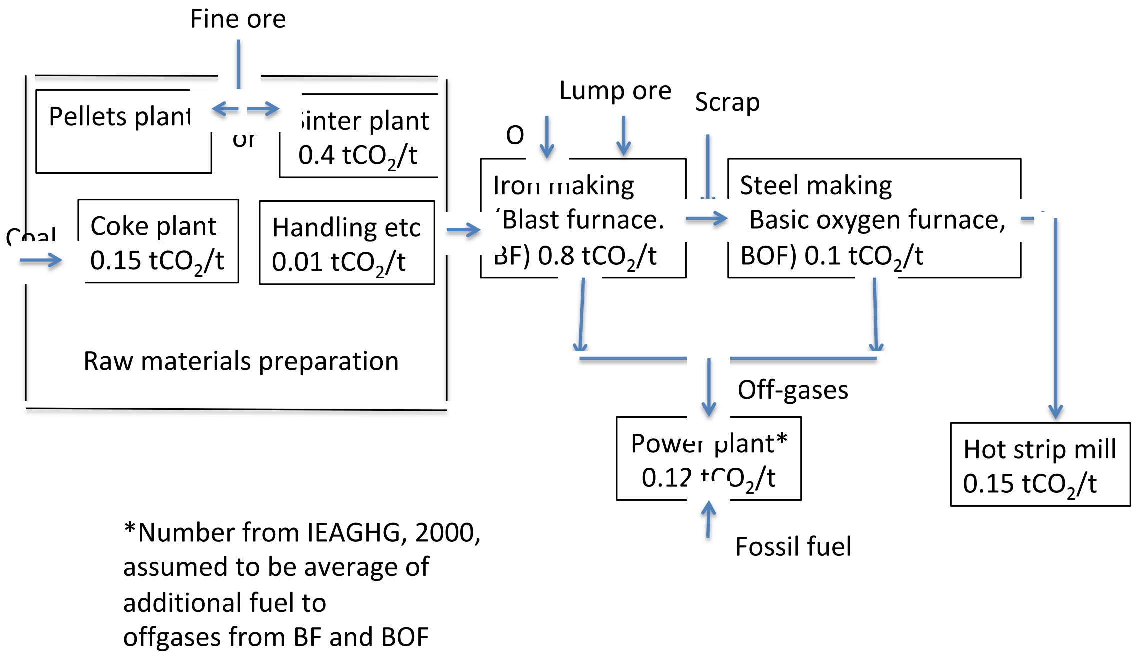

Figure A.1.1. The integrated steel mill/blast furnace route to steel production. (Based on Figure 2 in Birat and Maizières-lès-Metz, 2010, and on IEAGHG, 2013).

The CO_2 emissions for crude steel will be 1.46 t CO_2/t crude steel without counting the power station (direct emissions) and 1.61 t CO_2/t hot rolled coil steel. Emissions from off-site power production and from mining of coal and ore, which leads to indirect emissions, are excluded here[9]. The BF is the principal CO_2 emissions source, accounting for 70% of the CO_2 emissions of the whole process, with a concentration of around 22%-vol, while the BOF gas (BOFG) has a concentration of approximately 14%-vol (0.10 t CO_2/tSteel). Another important CO_2 emissions source is the Sinter plant (0.4 t CO_2/tSteel), but with a much lower CO_2 concentration (5%) and additional CO_2 is emitted in the coking oven and the CHP (combined heat and power) plant. The most commonly investigated configuration for CO2 capture, combines few emission stacks and results in a CO_2 concentration of approximately up to 30% (IEAGHG 2018).

Characteristics of the specific CO_2 emissions from a typical integrated steel plant are as shown in as in Figure A.1.1 and summarised in Table A.1.1, use of off-gases as fuel taken into consideration.

Table A.1.1. Characteristics of exit gases from the different facilities in an integrated steel mill, with use of off-gases as fuel taken into consideration (ISO, 2016)

Facility	**CO_2 emissions, tCO2/t rolled coil**	**CO_2 concentration, %**	**Pressure of gas stream, Mbar**	**Other parameters**
Coke plant	0.15	2	30	N_2, CH_4, H_2,CO, , water, dust, tar, H_2S
Sinter plant	0.40	5		N_2, CO, O_2, NO_x, SO_x, water, dust, H_2S

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[9] To note that this is one of several configurations of an integrated steel mill. Other publications may show somewhat different distributions of emissions from the various plant facilities.

Blast furnace	0.80	25	50	, H_2, CO, N_2, water dust, H_2S, NOx, SOx
Basic oxygen furnace	0.10	20	20	H_2, CO, N_2, water, dust, H_2S
Other	0,01			
Total crude steel	1.46			
Casting, rolling, finishing	0.15			
Total hot rolled coil	1.61			
Power station	0.1 – 0.15(?)	27		**N_2, O2, NO, NO_2, SO_x, water, dust,**

Primary steel production: The direct reduced iron (DRI) – electric arc furnace (EAF) route
This route has a global a share of roughly 5-6% (ClimateTechWiki, Birat and Maizières-lès-Metz, 2010). Direct reduction consists of the reduction of iron ores into solid primary iron. The solid product is called direct reduced iron (DRI) and is mainly used as feedstock in electric arc furnaces (EAF). It can also substitute scrap in a basic oxygen furnace (BOF). In the DRI route, reformed natural gas is mainly used to reduce the iron ore. The use of this route can result in a reduction of up to 20-25 % in CO_2 emissions compared to the primary route of steelmaking (ZEP, 2015; EUROFER, 2013). Use of DRI is expected to increase in the future. Figure A.1.2 shows a schematic of the DRI process. The main CO_2 emitters are the DR and EAF process steps. However, the CO_2 intensity of the latter is highly dependent on how the electricity for the EAF is produced.

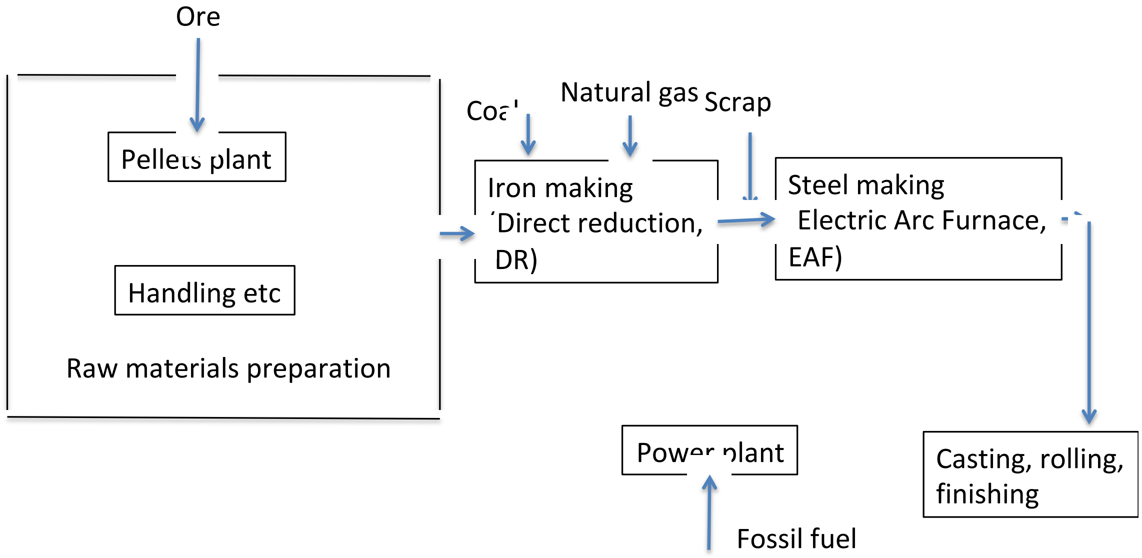

Figure A.1.2. The direct reduced iron – electric arc furnace (DRI-EAF) route to steel production. (Based on IEAGHG, 2013).

The CO_2 emissions for crude steel will be 1.31 t CO_2/t crude steel without counting the power station (direct emissions) and 1.55 t CO_2/t hot rolled coil steel. Emissions from off-site power production and from mining of coal and ore, which leads to indirect emissions, are excluded here. These numbers are about 20% higher than indicated by, for example, Birat and Maizières-lès-Metz (2010) and Carpenter (2012).

Secondary steel production: The electric arc furnace (EAF-scrap) route

This route is based on scrap iron and has a global share of roughly 25% (ClimateTechWiki, Birat and Maizières-lès-Metz, 2010). In this process, scrap steel is melted in the EAF to produce crude steel that is further processed, Figure A.1.3. This process leads to CO_2 emissions that are only 30 – 40 % of the integrated steel mill (Birat and Maizières-lès-Metz, 2010; IEAGHG, 2013; de Beer ate al., 1999). Emissions are from the production of electricity for the EAF.

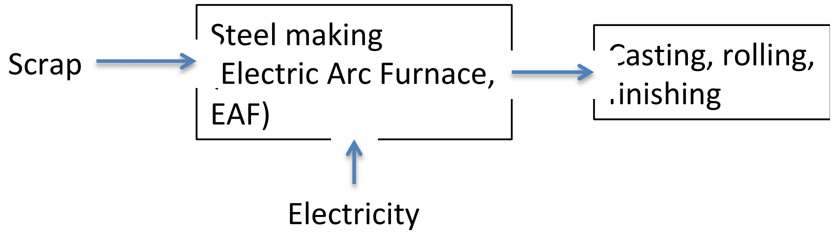

Figure A.1.3. The secondary route to steel production. (Based on IEAGHG, 2013)

Primary steel production: Smelting reduction- basic oxygen furnace (SR-BOF) route

This route is shown schematically Figure A.1.4. It accounts for less than 1% of the global steel production and has CO_2 intensity that is about 25 % higher than the BF-BOF route (Eurofer, 2013). This route will not be considered further.

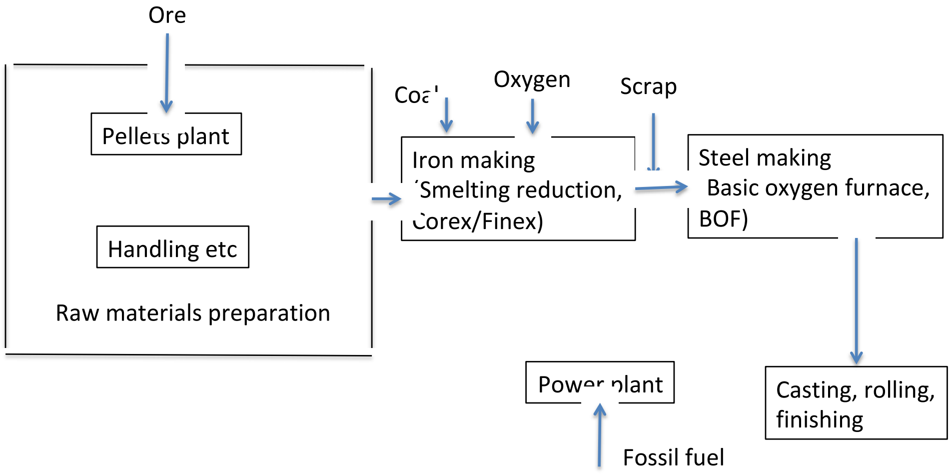

Figure A.1.4. The Smelting reduction- basic oxygen furnace (SR-BOF) route. (Based on Eurofer, 2013)

A.1.3. Non-CCS technologies for reduction of CO_2 emissions form the steel industry

Ways that the steel industry can reduce CO_2 emissions include:

- Improving energy efficiency, which may reduce CO_2 emissions by 10-25 % (Energy Transition Commission, ETC, 2018b)
- Changing process for production of virgin steel
- Increasing the use of recycled steel
- Fuel switching by replacing the fossil fuel with biomass.

For production of virgin steel there are several non-CCS options:

- Continuing with a fossil fuel based metallurgy
- Shifting to a non-fossil based metallurgy, including
    - Use of carbon from sustainable biomass
    - Electrolysis (by renewables).

Continuing with a fossil fuel based metallurgy

This route will include:

- Improve existing processes in order to reduce the use of carbon:
    - Recycling of steel gases available on site for power and heat production (already implemented at several steel mills)
    - Partial replacement of coal by natural gas
    - Increased use of direct reduced iron DRI) – electric arc furnace (EAF) route, already responsible for 5-6% of world production
- Further develop and implement innovative technologies.
    - Several innovative technologies are under development and testing around the world, including the European programme "Ultra Low CO_2 Steelmaking (ULCOS)" and STEPWISE, the Japanese programme "CO_2 Ultimate Reduction in Steelmaking process by innovative technology for cool Earth 2050 (COURSE 50)", the programmes in South Korea under POSCO RIST, and projects under the American Iron and Steel Institute (AIS). The CO2STCAP project is advancing on partial CO_2 capture and its integration with other low carbon measures. For more details on one or more of the technologies, see for example IEA, (2017); Eurofer (2013); ISO (2016); Birat and Maizières-lès-Metz (2010); and ZEP (2015).

Estimating the CO_2 reduction potential of this route is difficult, as several assumptions will have to be made. Some indications can be given:

- Replacing the BF route with the DRI could reduce the emissions by 20% or more
- Implementing innovative technologies may give reductions of up to 20% (Eurofer, 2013, for the ULCOS technologies).

Shifting to a non-fossil based metallurgy

This route includes:

- Development of new processes (already being studied) that would produce iron using electrolysis reduction systems with renewable electricity. Examples are the ULCOS technologies Ulcowin and Ulcolysis (IEA, 2017; Eurofer, 2013) and the Molten Oxide Electrolysis (MOE) of AIS.
- Using carbon-free H_2 to replace fossil fuel as reducing agent. The H_2 would have to be produced by electrolysis of water using renewable electricity. For Europe only, such processes would require a rise in the CO_2 free electricity demand of about 500 TWh per year (15% of the electricity consumption of the EU), which needs to be available 24/7. This is not a viable route if other industries follow suit (ZEP, 2017). Steam reforming of natural gas or syngas with CCS is the alternative.
- Biomass can be used to generate the reducing agent (carbon), either from charcoal for example or syngas. Biomass in such a scheme would need to be grown effectively near the place of use and in sufficient quantities to make it economically viable and sustainable. Biomass can be added as charcoal in blast furnaces, to the coke oven charge, burned as fuel in steelmaking reactors or used in direct reduction as syngas etc. This is already being done in Brazil, and the Canadian Steel Producers Association (CSPA) has a strong focus on this approach. Interest is also strong in Australia and Europe. There will still be CO_2 emissions and life cycle analysis will have to be applied to show that the use of biomass does lead to a reduced net carbon footprint.

Increase use of recycled steel

A significant reduction in CO_2 emissions will be achieved if a large portion of increased demand for steel is met by scrap-based production, as the EAF-scrap route have 30-40 % lower emissions than the blast furnace route. Estimates of the potential for recycled steel is 40 – 50 % of total production in the 2050-2060 time frame (IEA, 2017; ETC, 2018). If the electricity for the EAF is produced from renewables, the potential reduction of CO_2 emissions will be 100%.

Table A.1.2 shows the CO_2 reduction potential of some of these technologies, without CCS, and with development/implementation perspectives.

Table A.1.2. CO_2 abatement potential for some innovative low-carbon steel processes

Technology	Potential for CO_2 reduction, %	Status of development/expected deployment	Source	Challenges
Switch from integrated route to DR-EAF route	15 - 20 % (20-25% of 70%, BF-BOF present share)	Already deployed	Birat and Maizières-lès-Metz (2010); and Carpenter (2012); IEAGHG, 2013; Eurofer, 2013	Mainly applicable green-field plants, costs limit retrofitting (if at all possible) brown field plants
Innovative technologies w/o CCS	< 20%	Pilots and demos done, deployments from 2020 onwards	Eurofer, 2013	Timing and cost
Electrolysis	30 % with present electricity mix, 98 % with CO_2 fee electricity generation	Pilot 2020, demo 2030, deployment post 2040	Eurofer, 2013	To obtain sufficient renewable electricity is available to serve all intended purposes
Use carbon-free H_2 as reducing agent in DRI-EAF route	100 if produced by electrolysis using renewables; 90 if reforming with CCS;			To obtain sufficient renewable electricity available to serve all intended purposes
Replace fossils with biomass (charcoal)	??			Large amounts of sustainable biomass required, LCA must prove a net reduction
Use of recycled steel (scrap) in EAF	30 – 100, depending on the source of electricity for the EAF			To obtain sufficient renewable electricity is available to serve all intended purposes

The needed reductions of direct (process-related) CO_2 emissions from the iron and steel industry of 55 – 60 % in 2DS and > 80% in B2DS will not be achievable using innovative technologies in fossil based metallurgy nor by non-fossil metallurgy. CCS will be needed, as concluded by IEA, 2017; Eurofer, 2013; Birat and Maizières-lès-Metz, 2010; and ZEP, 2015).

A.1.4. CCS in the steel industry

In the EAF-scrap route, the CO_2 emissions are linked to the electricity production. Consequently, the CCS system would be implemented in the power plant and, thus, will not be analyzed further because it is out of the scope. For the rest of the routes, the CO_2 emissions come from multiple sources and the allocation of the direct emissions among the various facilities within the mill will be site specific, it is difficult to generalize how CO_2 capture can be applied.

Based on the multiple point sources of CO_2 in the production of iron and steel, this sector offers flexibility for a wide variety of capture configurations as reflected in the literature. For any specific technology, the carbon capture cost will vary depending on the implementation pathway. Additionally, most of the studies generally considered partial capture systems, even though the system itself is considered full capture on the treated flue gas as only part of the total emissions will be treated (IEAGHG, 2018).

In the literature, the carbon capture systems applied to this sector are: chemical absorption (using traditional and advanced solvents), PSA and VPSA, WGS and SEWGS, oxyfuel (as TGROBF configuration), and hybrid technologies (oxyfuel plus chemical absorption or VPSA). Use of membranes is also being studied and considered (CORESYM, 2017; RamÃrez-Santos et al., 2017; Lie et al., 2019).

In theory, CO_2 capture systems can be implemented independently per CO_2 source. That would mean that the integration and impact the production process would be at a lower level than implementing a single capture system.which could be costly. Moreover, technologies at low Tehnology Readiness Level (TRL) are not advanced enough to ensure its efficient operation. Additional specific challenges per technology are included in the table below (IEAGHG, 2018). The most common carbon capture configuration treats the gas emitted in the blast furnace or the combination of the gases from the coke oven, blast furnace and basic oxygen furnace, which are sent to a CHP (concentrated up to approximately 30% CO_2).

In principle, all the available CO_2 capture routes are suitable for retrofitting iron and steel production plants. Chemical absorption is more suited to reduce emissions in fluegas with a low CO_2 content, such as in BF+BOF and Corex configurations, while physical separation principles would be more suited to cases with a high partial pressure of CO_2 in the fluegas, as in adsorption-based systems such as PSA or VPSA (pressure swing adsorption or vacuum pressure swing adsorption), and WGS or SEWGS (water-gas shift or sorption enhanced water-gas shift reactions) (IEAGHG 2013).

For example, in the BF-BOF route it is envisaged that CO_2 capture can be applied to an off-gases fired power plant using a post-combustion technology such as amine scrubbing. This could lead to reductions of CO_2 emissions in the range of 80 % or more. Post-combustion technology will be suited for this. It is in operation at full scale power plants; it will, however, need to be modified and qualified for steel production. The choice of post-combustion CO_2 capture technology may have to be site specific.

Alternatively, one could focus on the blast furnace, responsible for roughly 50% or more of the CO_2 emissions, again using a post-combustion capture technology.

In the DR-EAF route, the reducing H_2 is produced from reformed natural gas or syngas. H_2 and CO_2 are separated after the reforming by methods described in Section A.5 on hydrogen production. This approach has already been commercially implemented in the Al Reyadah steel mill in United Arab Emirates. 800 kt of captured CO_2 per year is used for enhanced oil recovery purposes (Global CCS Institute (GCCSI) undated). This business option will not be available everywhere. At HYL in Monterrey, Mexico the DRI process has been operation since the 1950ies, and at ArcelorMittal at Lazaro

Cardenas in Mexico, CO_2 is removed from the reducing gas by amine-based chemical absorption. Steelmakers have already several pilots with amine scrubbing in service (Voest, Nippon Steel, Thyssen Krupp pilot Carbon2Chem) or in development (ArcelorMittal 3D pilot in France). The footprint of this technology is very low since the waste heat from steel making is used to regenerate the amines and solvents. But since there is not enough waste heat available another part of the CO_2 is separated with a PSA (Steelanol project of ArcelorMittal). Finally membrane-based separation is used to scrub CO_2 from the fumes of steelmaking, which contain a significant level of CO_2. This rather impure CO_2 is used for slag and mineral carbonation.

Table A.1.3 indicates the possibilities for CO_2 reduction by CCS for the alternative routes to steel production, with the most promising CCS technologies, their reduction potential, and status. More thorough discussions can be found in, amongst others, ISO (2016), Eurofer (2013), GSSCI (2016), and Carpenter (2012)

Table A.1.3. CO_2 abatement potential by CCS for steel production processes. (Based on ISO, 2016; Eurofer, 2013; GCCSI, 2016))

Production route	**Facility**	**Most advanced capture technology**	**Potential for CO_2 reduction by CCS (from baseline integrated), %**	**Challenges**	**Status of development/ expected deployment**	**Source**
Integrated steel mill, BF	Coke plant	NA?		High costs, lack of commercial and political incentives		
	Sinter plant	Post-combustion	20-30	High costs, lack of commercial and political incentives	Deployed in power plants	
	Blast furnace	Post-combustion	30-50	High costs, lack of commercial and political incentives		
	Power plant burning BF and BOF offgases	Post-combustion	70 -90	High costs, lack of commercial and political incentives	Deployed in power plants	

	CCS on all furnaces	Post-combustion	->100	High costs, lack of commercial and political incentives	Deployed in power plants	
	Casting, rolling, finishing					
DR-EAF	Reforming of natural gas	Chemical or physical absorption	->100 excluding electricity generation			
Innovative steel making w/o CCS (under research progarmmes)[10]		Hisarna, Hismelt Use of H_2 in DRI	60 – 80	High costs, lack of commercial and political incentives		Eurofer, 2013

Summing up, CCS technologies applied to steel production are able to reduce CO_2 emissions sufficiently to achieve the reduction necessary to meet the Paris targets but some non-technical obstacles remain. Common to all industries, the implementation of CCS in the industrial sector can offer operational challenges, while there is a need of transport and storage infrastructure and public acceptance could play a decisive role. Specific for the steelmaking sector, some technical uncertainties due to the lack of large demonstration projects could add implementation risks.

A.1.5. Costs and challenges

Table A.1.4 summarizes some challenges with the various CCUS technologies that may applied by the steel industry.

Table A.1.4. Some challenges with the various CCUS technologies that may applied by the steel industry

CO_2 capture technology	**TRL**	**Specific challenges**
Chemical absorption	9*	Significant steam demand
Oxyfuel	6	Integration comprises changes on the production process
PSA	3***	Operational challenges
VPSA	3***	Working under vacuum could offer operational challenges
WGS	5**	Stability of the sorbent
SEWGS	6**	Stability of the sorbent

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[10] Examples of current initiatives are ULCOS (using advanced steelmaking process such as Hisarna, DRI, iron ore electrolysis, and TGROBF), COURSE50 (combining few technologies to reduce CO_2 emissions), Carbon2Chem (CO_2 conversion to chemicals), IGAR (plasma-based process), Hybrit (H_2 based DRI), SALCOS (H_2 based DRI), H_2Steel, SIDERWIN (ULCOWIN technology, an electrolysis-based process). Steelanol is developing a process to convert the blast furnace CO to bioethanol

Hybrids	1	Summing up individual challenges of each technology

*using commercial solvents

** IEAGHG (2014) assessed SEWGS as TRL5. TRL 6 would be reached soon based on the results of the STEPWISE project

***As assessed in IEAGHG (2014)

A.1.6 . Conclusion

Of the technology options considered for reduction of CO_2 emissions from steel production, CCS is the only one that can significantly reduce process emissions in the short and medium terms[11]. The technology exists and has been implemented in the power sector. Qualification for steel production is needed, as are viable commercial and policy incentives to promote the CCS deployment.

A.2. The cement industry

A.2.1. Present and future CO_2 emissions from cement production

Future emission numbers vary according to source. Here we have used numbers from IEA (2017), as these are based on scenario modelling and consistent through all industries. The direct emissions contribute 6-7 % of the global anthropogenic CO_2 emissions, or about 2230 Mt CO_2 in 2014, associated with a production of 4175 Mt cement (IEA, 2017). In the 2DS the emissions are expected to come down to just below 1700 Mt CO_2/year by 2050, compared to almost 2300 Mt CO_2/year in RTS.

The cement industry is on the right track, as shown in Table A.2.1. The most recent GNR (“Getting the Numbers Right”) illustrate the continuous efforts of the cement sector in further mitigating its CO2 emissions. Full details including historical information, is available online at https://www.wbcsdcement.org/GNR-2016/ via the Global Cement and Concrete Association (GCCA) website https://gccassociation.org/.

The 2016 dataset consolidates information from 849 cement manufacturing facilities (such as integrated plants and grinding centres) around the world. These facilities produce approximately 19% of global cement production. 80% of the data provided is independently verified.

Table A.2.2. Development of important cement production parameters 1990-2016 (from World Business Council for Sustainable Development, WBCSD, undated)

Global data		**1990**	**2014**	**2015**	**20106**
Clinker (grey) volume	Million tonnes	423	671	680	606
Cementitious[12] volume	Million tonnes	512	905	916	818

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[11] An example can be seen in Arens et al. (2017). This study shows that the German steelmaking industry will not achieve the national and European climate change goals only with measures different to CCUS

[12] Cementitious products consist of all clinker produced for cement making or direct clinker sale, plus gypsum, limestone, cement kiln dust and all clinker substitutes consumed for blending, plus all cement substitutes

Gross[13] CO_2 specific emissions (cementitious)	kg/tonne	761	637	634	640
Net[14] CO_2 specific emissions (cementitious)	kg/tonne	755	615	617	616
Kiln fuel use	MJ/tonne clinker	4254	3499	3511	3519
Specific electricity use (cement)	kWhrs/tonne	119	101	100	103
% clinker in cement	%	83	74.6	74.9	75.0
% alternative fuel use	%	2.0	15.7	15.9	16.7

A.2.2. What are the sources of CO_2 emissions from the cement industry?

CO_2 emissions are an unavoidable by-product of the cement manufacturing process and there are two main sources to CO_2 emissions; 1) the raw material (limestone) used in cement manufacturing accounts for roughly 2/3 of the total CO_2 emitted from the cement plant (this is due to the limestone decarbonation process ($CaCO_3 \rightarrow CaO + CO_2$); and 2) the other 1/3 generally comes from the combustion of fossil fuels to obtain the heat required for the mineralogical transformation (calcination of limestone and formation of new minerals, collectively called clinker).

<u>Short Description of Cement Manufacturing</u>

Figure A.2.1 illustrates the main steps in the cement manufacturing process and a mass balance (CEMBUREAU – 2006; Schorcht et al. 2013) for the production of 1 kg of cement using the dry process with petcoke as the fuel.

1. Limestone, the main ingredient for making cement, is extracted from a local limestone source. Limestone is transported from the quarry to the cement plant, where it is crushed to a maximum size of 10-15 mm.
2. The limestone is mixed with correction materials such as silica, iron oxide and alumina oxide and milled to a fine, dry powder called raw meal.
3. The raw meal is preheated to approximately 850 °C in cyclone towers, and then calcined $CaCO_3 \rightarrow CaO + CO_2 \uparrow$) in the pre-calciner before entering the rotary kiln.
4. In the kiln the raw meal is further heated to 1450 °C. At this temperature the different clinker minerals are formed through reactions between the different oxides in the calcined meal. During the firing process, a partial melting phase is achieved and particles are sintered together forming granules called clinker.
5. After cooling, the clinker is mixed with gypsum (to control the hydration process) and milled to cement. The type of quality of the cement depends on the chemical composition and the degree of grinding of the clinker.

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[13] Gross CO2 emissions includes calcination, conventional kiln fuels, alternative kiln fuels, non-kiln fuels, with biomass CO2 as a memo item

[14] Net emissions are calculated from gross emissions minus emissions from the use of alternative fuel

6. Finally, the cement is pneumatically conveyed to cement silos for bagging or bulk storage and shipment.

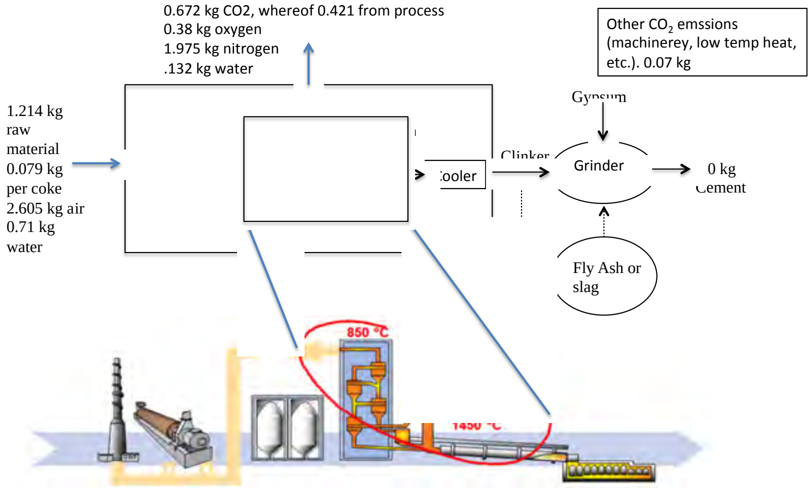

Figure A.2.1. Main steps in cement manufacturing and mass balance in a typical cement plant that uses the dry process with petcoke as the fuel (Source: CEMBUREAU – 2006, Schorcht et al. 2013). Additions like fly ash, slag, limestone filler, pozzolans are added according to the cement type produced.

The main CO_2 emissions occur at steps 3 and 4 (>99% direct emissions and >90% of overall emissions). The other steps depend to a large extent on use of electricity. These latter steps will not be considered further.

The emissions are summed up in Table A.2.2.

Table A.2.2. Characteristics of CO_2 emissions from the different facilities in cement plant (Sources: WBCSD, undated)

Facility		**CO_2 emissions, tCO2/t clinker**	**CO_2 concent-ration, %**	**Pressure of gas stream, Mbar**	**Other parameters**
Process	Calcination	0.530	~ 20	0.1	NO_2, SO_2, CO, TOC/VOC, HF, HCI, dust, metal traces
Thermal energy	Combustion	0.303			
Other	Not applicable	0.09			

Table A.2.2 shows that the cement industry might provide more favourable conditions for the application of carbon capture measures than other industrial installations due to comparatively higher CO_2 concentrations in their off-gas (ECRA, 2007).

A.2.3. Non-CCS technologies for reduction of CO_2 emissions in the cement industry

The cement industry developed several roadmaps towards a low carbon economy.

In 2009, the International Energy Agency (IEA) and the WBCSD (IEA and WBCSD, 2009) together developed a first cement industry technology roadmap based on IEA's modelling and on 38 technology papers developed for the WBCSD Cement Sustainability Initiative (CSI) by European Cement Research Academy (ECRA.)

In 2016, the CSI initiated an in-depth review of the technology papers from 2009 (IEA and WBCSD, 2009) and delivered in June 2017 (ECRA, 2017) a compilation of 52 individual papers on well-known existing technologies and seven additional summary papers describing state-of-the-art and anticipated technological developments that can further enhance mitigation of CO_2 emissions in cement production. The report also includes an assessment of the level of possible implementation, the challenges and costs of these technologies in future scenarios for 2030 and 2050. Also, regional low carbon economy roadmaps have been and are being developed in different regions of the world (Europe, India, Brazil).

The IEA-CSI technology roadmap (IEA and CSI, 2018) describes strategies or levers to reduce CO_2 emissions footprint of cement production and for supporting the global cement industry in achieving the roadmap vision pathway by:

Thermal efficiency: Cement manufacturing requires raw materials to be heated to 1450°C and is thus energy intensive, even if thermal energy only accounts for approximately 35% of the cement industry's CO_2 emissions. Improving energy efficiency: deploying existing state-of-the-art technologies in new cement plants and retrofitting existing facilities to improve energy performance levels when economically viable. Further, waste heat recovery is being investigated and should be encouraged (CEMBUREAU, 2013). Overall emission reduction potential may be in the 8-10% range (ETC, 2018c; CEMBUREAU, 2013).

Fuel mix or fuel switching. Continued use of alternative fuels such as industrial and domestic waste, liquid- and solid hazardous waste, animal waste, and biomass will contribute to further reductions of CO_2 emissions from the cement industry. The % of alternative fuels averaged 16.7% globally. In Europe, 1/3 of fuel for cement kilns is presently used as alternatives to fossil fuel (CEMBUREAU, 2018) and there is a significant global potential. ETC (2018c) indicates a global potential of 30%, CEMBUREAU (2013) as high as 60%. In some countries it is already higher than 90%.

Clinker substitution. Clinker can be blended with a range of alternative materials that include finely ground limestone, and industrial by-products like slag and fly ash. ETC (2018c) indicates a global savings potential in CO_2 emissions of 50% or more, the IEA indicates a potential contribution of 37% to the cumulative savings by 2050, whereas CEMBUREAU (2013) indicates only 4% for Europe. Availability will vary with location.

Novel cements/feedstock change (raw material substitution).
If limestone could be replaced as raw material for the cement production, significant savings in CO_2 emissions would be achieved. The availability of non-carbonated raw materials that meet the criteria for use as substitute for limestone (e.g. not too high concentration of silica, alumina, magnesium or sulphur), particularly near cement plants, is limited. Also their commercial availability and applicability varies widely. The IEA has considered that it was therefore premature to include them in a technico economic based evaluation of least-cost technology pathways for cement production.

Electrification. Neither CEMBUREAU (2013) nor the IEA-CSI (2018) include the use of process electrification to provide the heat required by the kilns. This would have the potential to reduce 1/3 of the CO_2 emissions from a typical cement plant. However, the abatement potential is limited in many regions. ZEP (2017) estimates that the electricity to produce 1 million tonnes of cement will be sufficient to supply about 250 000 European homes. All European cement production would require the electricity produced by Poland today. Moreover, electrical power is far from being decarbonized today (Emission factor is 360 g CO_2/kWh in Europe)

For more details on CO_2 reduction measures in the cement industry, see European Cement Research Academy, ECRA (2017) and IEA-CSI technology Roadmap (2018).

The CO_2 reduction emissions impact of these levers is not always additive since they can individually affect the potential for emissions reductions of other options. In addition, recent reports (ETH Zurich, 2018a,b) have pointed at the need to endorse a whole value chain approach that would allow further CO_2 savings with investments costs spread over the value chain (recycling of concrete with fines reused as raw material for clinkers; optimisation of the concrete mix design via better aggregate packing and not exceeding the requirements of codes and standards to avoid the overuse of cement in concrete, building design).

Table A.2.3 summarises the CO_2 reduction potential of some of these technologies, without CCS, and with development/implementation perspectives.

NOTE: It is unclear from the references if the indicated reduction potentials apply to the process step, to the overall plant or regionally/globally for the industry. Here the interpretation is that they apply to the process steps, thus, the overall impact on a cement plant is the potential times the contribution.

Table A.2.3. Impact of CO_2 abatement potential for some innovative low-carbon cement processes on the overall plant carbon footprint

Technology	**Potential for CO_2 reduction on a cement plant,** **%**	**Status of development/expected deployment**	**Source**	**Challenges**
Kiln efficiency	3-4 (8-10 of 1/3)	Modern and energy efficient kilns already installed on a high number of cement plants world-wide	ETC (2018c), CEMBUREAU (2013)	None really. retrofitting not complicated, may be positive business case
Fuel mix	10-15 (30-40 of 1/3[15])	Used extensively in Europe (above 40%)	ETC (2018c), CEMBUREAU (2013)	Availability of biomass and waste (increased competition); waste legislation; biomass must be sustainable
Clinker substitution	2-3 in Europe (4 of 2/3), perhaps 30 elsewhere (50 of 2/3)	Already used in small amounts	ETC (2018c), CEMBUREAU (2013)	Availability of raw material; meeting standards and market acceptance
Novel cements	50 – 90, depending on how much traditional cement is replaced by novel	Many types patented, some under development but only at early stages	ETC (2018c), CEMBUREAU (2013)	Availability of raw material; meeting standards and market acceptance; time to commercialisation and needed volume

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[15] Considering all alternative fuels as carbon neutral

Electrification	~30		ZEP (2017)	Availability of renewable electricity Only a solution for combustion emissions

SUMMING UP: The needed reductions of direct CO_2 emissions from the cement industry of > 60% in B2DS will not be achievable using only non-CC technologies. CCUS will be needed along with other technologies, as concluded by IEA, 2017; and ZEP, 2015. It will also be essential to develop measures down the value chain.

A.2.4. CCUS in the cement industry

Modern cement plants operate today at or close to the theoretical limits of efficiency and deployment of CCUS seems to be an essential technology in short/ medium term perspective to meet future global climate change goals.

CCU and CCS options for the cement industry are described in ECRA State-of-the-Art paper 6 and 7.

Status on CCS, with emphasis on capture technologies, future perspectives and need for RD&D.
In order to evaluate the realism of deployment of carbon capture to mitigate the environmental impact, testing on real cement flue gas is required.

There are different techniques currently explored for CO_2 capture in the cement industry. There are five major projects in the EU:

- Norcem CCS project, which is based on absorption by amines
- Ecra CCS Oxyfuel project
- CEMCAP, which is studying several technologies
- Leilac, which is based on direct separation of calcination emisssions
- Cleanker, with is based on the carbonate looping technology.

The Norcem project

One of the preferred techniques for capturing CO_2 in cement plants is post-combustion capture. Such technique is tested in some industries but to date, no cement plants utilize capturing technology to mitigate its CO_2 emissions. Norcem AS (Norcem) and its parent company HeidelbergCement Group (HeidelbergCement) joined forces with the European Cement Research Academy (ECRA) to establish a small-scale test centre (up to 150 kg CO_2/hour) for studying and comparing various post-combustion CO_2 capture technologies and determining their suitability for implementation in modern cement kiln systems. The small-scale test centre was established at Norcem's cement plant in Brevik (Norway) in 2014, and has been used to study various post-combustion carbon capture technologies. The project was launched in May 2013 and concluded by July 2017. The project was financially supported by Gassnova through the CLIMIT-Program.

The project objectives have been as follows:

1) Establish a small scale test centre with all utility requirements set by the technology providers
2) Testing and studying four various post-combustion carbon capture technologies under *real process conditions*
3) Compare the technologies in a full-scale perspective and determine how suitable these are for implementation at modern cement kilns (based on the benchmark analysis).

The project mandate involved testing of more mature post-combustion capture technologies initially developed for power generation applications, as well as small-scale technologies at an early stage of development. The project does not encompass CO_2 transport and storage.

Technologies selected in Phase I (2013-2014):

- Aker Solutions (AKSO) **-** Amine Technology (1. Generation)
- RTI **-** Solid Sorbent Technology (3. Generation)
- KEMA GL/ NTNU & Yodfat Engineers **-** Membrane Technology (MC) (3. Generation)
- Alstom Power **-** Regenerative Calcium Cycle (2. Generation).

Two technologies were further studied in Phase II (2015-2016):

- RTI **-** Solid Sorbent Technology (3. Generation)
- NTNU & Air Products **-** Membrane Technology (MemCCC) (3. Generation).

All in all, the Norcem CO_2 Capture project has been a great success. Both Norcem (the cement industry) and the technology providers have learned a lot from pilot design and construction, preparations and follow-ups of infrastructures, testing on real conditions and based on field-trials-data, calculating the economic performance of the technology.

The Brevik project has shown that capture technologies development are demanding, time consuming and requires considerable resources. Important learning was that testing on real process conditions is vital for the technology development as the conditions might be quite different from the ideal environment in the laboratory. The test project in Brevik showed that not all technologies managed to mature their technology to the next readiness level (based on the US TRL Scale), due to unforeseen challenges with technology design.

The Brevik project concluded that in a 2022-perspective, only the amine technology provided by Aker Solutions is ready for full-scale demonstration. The technology is tested on real conditions for approximately 8000 testing hours, and with good performance results. However it is likely that a palette of technologies will be available and suitable for the cement industry in the future. Local conditions may be decisive when determining which technology should be applied at a given plant.

An important message to technology developers is to start the maturing process today in order to be ready for full-scale deployment in perhaps 8-10 years-time. A clue is to develop mobile test pilots that can be installed and tested at various real life exhaust gas applications, including cement.

The Norcem project has shown that costs can be reduced if plant surplus heat is utilized. However, using only this energy source for a post.combustion solution based on amines, the amount of CO_2 captured will be reduced, in the Norcem case to around 40%.

The ECRA Oxyfuel project

The second technique is oxyfuel**.** ECRA's long-term carbon capture research project started in 2007 and has advanced to the stage where definite steps towards establishing an oxyfuel kiln can now be taken and oxyfuel technology will now be tested in two cement plants in Europe. Such kilns are intended to provide insight into the industrial-scale operation of a technology, which provides a high CO_2 concentration exhaust gas stream for further carbon capture. It is also planned to process a small part of the CO_2 to test its further utilisation. Oxyfuel technology is currently seen as a more economic candidate for CO_2 capture at cement kilns although it is still very costly.

Oxy-combustion at a cement plant precalciner has also been tested during years 2009-2014 at pilot scale by Lafarge – Air Liquide – FLSmidth, concluding in the feasibility of the oxy-process with cement plant calciner gas which is the origin of 80 % of the CO_2 emitted by the cement plant. The CO_2 abatement rate with this process was estimated to be 50 % - 70 % of the cement plant emissions, depending on optimization level.

The industrial retrofit of the chosen cement plant with this capture process down to liquid storage in the harbour, limit of battery of the plant, was estimated to 62 €/t/CO_2

The CEMCAP project

The objective of CEMCAP was to prepare the ground for large-scale implementation of CO_2 capture in the cement industry. The project was finalized end October 2018. CEMCAP intended to leverage the oxyfuel capture technology, as well as three fundamentally different post-combustion capture technologies, to TRL 6 for cement plants, all of them with a targeted capture rate of 90%. For advancing oxyfuel capture of CO_2 from cement kilns, operation of the clinker cooler, ciner, and the rotary kiln burner have been experimentally investigated and demonstrated at pilot scale in CEMCAP. The world's first successful cooling of clinker under oxyfuel conditions has been demonstrated through a prototype oxyfuel cooler designed by IKN and installed at the HeidelbergCement plant in Hannover, Germany. VDZ, as a research partner, led the testing with hot clinker and laboratory analysis of the clinker product. The oxyfuel pilot scale clinker cooler is unprecedented in its innovative design, and the successful demonstration may be a game changer for oxyfuel operations in cement production. The tests with the clinker cooler prototype have been documented in a film that can be found on YouTube, or on the CEMCAP website. A cement burner was tested under oxyfuel conditions in a 500 kW rig at the University of Stuttgart. The burner was designed by Thyssen Krupp as a downscaled version of an industrial cement burner. These results were thereafter used for model validation and full-scale simulations of the burning process in the rotary kiln. Furthermore, the oxyfuel calcination was tested under relevant temperatures and residence times at University of Stuttgart, to verify the impact on calcination in an atmosphere with high CO_2 concentration. The CEMCAP experimental and analytical results will provide cement kiln technology providers and cement plant operators the necessary basis for a further scale up of the oxyfuel technology and deployment of oxyfuel processes in cement production. The post combustion capture technologies explored in CEMCAP are the CAP, CaL and Membrane Assisted CO_2 Liquefaction (MAL).

The LEILAC project

The third generation Carbon Capture for Cement Industry is being developed using a Direct Separation Reactor (DSR) at the calcining stage of a cement kiln. In the EU-Project LEILAC (Low Emission Intensity Lime And Cement) this technology is being demonstrated on a small industrial scale of 10 t/h raw meal feeding capacity. This process-integrated technology aims to enable the efficient capture of the unavoidable process emissions from lime and cement production, without an energy penalty. As such the costs of capture of the process-related CO_2 (which accounts for 2/3 of CO_2 emissions) are further reduced compared to 1st and 2nd generation CC-technologies as described before.

The construction of the demo-reactor has started in February 2018, commissioning is scheduled for end of 2018, followed by an intensive test-program in 2019. The roadmap for scale-up and roll-out of the technology is another important Work-Package of the LEILAC-project, to be delivered in 2019/2020.

The CLEANKER project

CLEANKER is a project funded by Horizon2020 addressing CO_2 capture from cement production. The core activity of the project is the design, construction and operation of a CaL demonstration system in the cement plant operated by Buzzi Unicem sited in Vernasca (Piacenza, Italy)

Table A.2.4. indicates the possibilities for CO_2 reduction by CCS for the alternative routes to cement production, with the most promising CCS technologies, their reduction potential, and status.

Table A.2.4. CO_2 abatement potential by CCS for cement production processes (post-combustion and oxy-combustion)

Facility/ Process	Most promising capture technology	Potential for CO_2 reduction by CCS on	Challenges	Status of development/expected deployment	Source

		cement plant, %			
Preheater, kiln	Post-combustion with amine	40 – 90, Depending on heat integration level possible in the cement plant	High costs, lack of commercial and political incentives	Tested and ready for full scale implementation	NORCEM
Preheater/precalciner kiln	Oxy-combustion	90 % capture potential (if both calciner and rotary kiln CO_2 is captured)	Needs an Air Separation Unit to produce the oxygen and a purification and liquefaction unit	FEED done. In funding collection phase	ECRA

SUMMING UP: CCS/U technologies have been demonstrated in cement production but technical, political and economical challenges remain.

The cement industry can also play a significant role when it comes to CCU and carbon removals:

CCUS - Mineral carbonation
Mineralization is used to describe the chemical process in which magnesium and calcium silicates react with CO_2 to form inert carbonates which can be used e.g. as construction materials. Both natural alkaline minerals (widely available) and industrial wastes and by-products such as W type fly ash (with high lime content), cement kiln dust, blast furnace slag can be used. Mineralization provides for a long-term CO_2 storage. The technology is still in the R&D phase and up to now no large-scale adsorption units are known for CO_2 capture from flue gases. According to the literature, the thermal energy requirement is around 3 GJ/t CO_2, which corresponds to 2.55 GJ/t clinker. Additional electrical energy is needed for crushing and grinding processes and for gas compression (see ECRA, 2017, technology paper for further details).

CCUS - Cements based on carbonation of calcium silicates
The carbonation of Ca-/Mg-silicates can also be considered as a possible CO_2 sequestration process. The first industrial trials to produce such cements (e.g. Solidia Cement) have been conducted. This non-hydraulic cement is used for Solidia Concrete, which is composed of the same raw materials and can be processed as ordinary Portland cement concrete. During the curing process up to 200 to 300 kg of CO_2 per tonne of cement can be absorbed. It is claimed that this technology reduces the overall carbon footprint associated with the manufacture and use of cement by up to 70% in comparison to Portland cement.

Carbon removal - Cement recarbonation
Cement recarbonation refers to the process where part of the CO_2 emitted during the cement production is re-absorbed by the concrete through carbonation. Carbonation is a slow process that occurs in concrete where lime (calcium hydroxide) in the cement reacts with carbon dioxide from the air and forms calcium carbonate. Concrete carbonation occurs on the surface of the concrete where it is in contact with air and moisture, and progresses through the concrete at a rate inversely proportional to its quality. At the end of their working life, reinforced concrete structures can be demolished. If the concrete is then crushed,

its exposed surface area increases, also increasing the recarbonation rate. The amount of recarbonation is even greater if stockpiles of crushed concrete are left exposed to the air prior to reuse. In order to benefit from the CO_2 trapping potential, crushed concrete should be exposed to atmospheric CO_2 for a period of several months before its reuse (e.g. as road underlay) which would require a new approach to managing construction waste. Studies have shown that up to 25% of the CO_2 originally emitted during the cement manufacturing can be re-absorbed, when proper recycling practices are applied. To optimize the CO_2 uptake at the end of life stage should be ensured that proper construction and demolition waste sorting and concrete recycling practices are in place.

To understand the full potential of recarbonation at the end of concrete life, fundamental research should be supported. Based on the outcome of research, an innovative set of policies on the treatment of crushed concrete building waste would enable recarbonation to reach its full potential.
Furthermore, based on the outcome of research, an innovative set of policies on the treatment of crushed concrete building waste would enable recarbonation to reach its full potential.

A.2.5. Costs and challenges

Estimates from GCCSI (2017) suggest that current cost of CCS applied to the cement industry range from 104 US$/t CO_2 to 194 US$/t CO_2, depending on location, for a first-of-a-kind plant. This is in line with McKinsey (2018), who estimated CCS costs above 100 US$/t CO_2, increasing with increasing electricity price. In the reference location, US, the reduction for the nth-of-a-kind the reduction could be around 17-18 %. This will imply an increase of each tonne of cement by 68 %, for the reference location, for a first-of-a-kind plant and 57 % for a nth-of-a-kind. CCS is cheaper than heat electrification for low carbon electricity prices above 50 US$/MWh for greenfields and 25 US$/MWh for brownfields. Biomass with CCS seems to be the cheapest option (McKinsey, 2018).

According to ETC (2018b), adding 100 US$/t will roughly double the cement price and lead to an increaseof 30% for concrete. However, this may induce an increase in the cost of the end product, e.g a building, from less than 1 % (Rootzen and Johnsson, 2016) to 3% (2018c).

In addition to the added cost for cement production with CO_2 capture there are challenges connected to lack of infrastructure for transport and storage of the CO2, as well as lack of business incentives and models for cost and risk sharing. It should also be noted that CCS technology will lead to a doubling of energy consumption.

Cement production is a competitive industry in a global market. It will face the risk of so-called carbon leakage, i.e. production is moved from countries/regions with restrictions on CO_2 emissions to countries/regions where there carbon pricing policies are not in place.

A.2.6. Conclusion

The cement industry has major challenges on CO_2 emissions reductions in order to meet the objectives of the EU and ofhe Paris Agreement. Compared to other sectors, the key difference for the cement industry (and also the lime industry) is t process emissions (coming from the calcination of the raw material lime stone) at about 2/3 of total emissions.

Emissions reductions technologies in the processes of cement production (as use of AFR, clinker substitution, increase of thermal and electrical energy efficiency, etc.) will continue to play a major role is the pathway to the objectives. The implementation and improvement and innovation of these technologies have to continue and to be supported.

Furthermore the use of the CO_2 from cement industry as feedstock for industries and processes is essential for the future of the role of cement industry in the low carbon economy. Many smaller projects have been started or will be running up soon. In the next years, if properly supported by EU, govenments and industry significant progress is to be expected. Nevertheless CCU will not solve the whole issue of CO_2 emissions reductions for the cement industry.

The conclusion for technologies needed in the cement industry for geological storage of CO_2 is that several options are being developed with, at present (2018), post combustion absorption with amines (as projected for the Norcem project) is at sufficient Technical Readiness Level for a demo scale project. The other technologies are in different phases of TRL below demo scale level. A future low carbon cement industry d will require geological storage of CO_2.

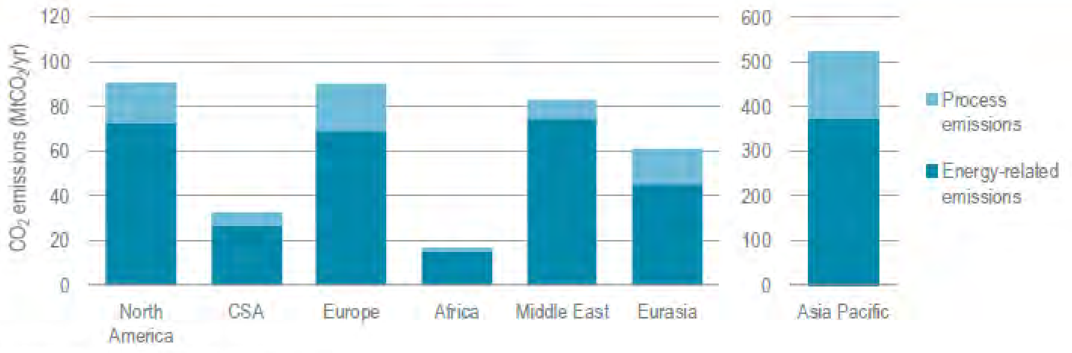
Not covered is the work on alternative binders, on cement reduction in concrete, and many other technologies that will contribute to the low carbon economy input of the cement and concrete industry. They will all be needed.

A.3. The chemical industry

A.3.1. Present and Future CO_2 emissions from the chemical industry

In general, the majority of the CO_2 emissions from the petrochemical industry are energy related emissions (energy to produce process heat or steam). This also means that the majority of the emission sources have relatively low concentrations of CO_2. Figurer A.3.1 shows regional distribution of direct CO_2 emissions from the petrochemical industry.

Figure 3.3 • Direct CO_2 emissions of primary chemicals by region in 2017



Note: CSA = Central and South America.

Figure A.3.1. shows regional distribution of direct CO_2 emissions from the petrochemical industry (Source https://www.iea.org/petrochemicals/)

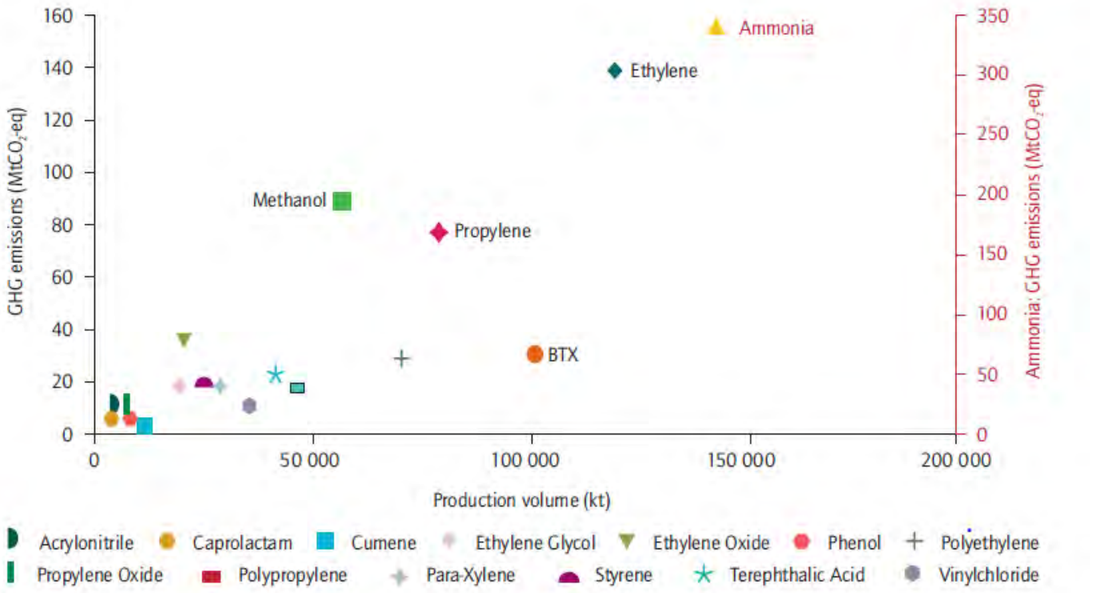
A.3.2. What are the sources of CO_2 emissions in the chemicals industry

Worldwide, the manufacture of 18 products (among thousands) from the chemical industry account for 80% of energy demand in the chemical industry and 75% of greenhouse gas (GHG) emissions, as seen in Figure A.3.2.

The petrochemical production starts with steam cracking of naphtha to ethylene, propylene, C_4 and aromatics (benzene, toluene, xylenes) and from these other petrochemicals are produceds such as Ethylene Oxide, Propylene Oxyde, acrylonitrile, Phenol, Styrene, that are in themselves intermediate molecules, to make more complex molecules. A very high part of petrochemicals are transformed in polymers/plastics with PE, PP and PS being among the most important. Methanol is another petrochemical that is made mostly from natural gas. All basic petrochemical building blocks (methanol, ethylene, propylene, C_4 and aromatics can also be made from coal in some regions, and in the future waste could be used as an alternative feedstock to produce these building blocks through chemical recycling.

The composition of streams containing CO_2 and emitted from chemical production are very different from one product to another as illustrated below for the two cases of Ethylene production using steam cracking and Ethylene Oxide production.

Diluted source of CO_2 from ethylene production:
Steam cracking is the process where gas (ethane, propane) and/or liquids (from LPG, naphtha, gas condensates to gasoline), is thermally cracked in the presences of steam at temperatures of 800-850C. The result is a mixture of CH4, ethylene, ethane, propylene, propane and heavier molecules (compoisition of cracked gas are highly dependent on the feedstock and processing conditions). This mixture is then separated in a downstream separation section using pressure and temperature to separate this cracked gas into pure components. The temperatures in the cracker ranges from 850C (cracked gas leaving the cracking furnace) all the way to -140C (in the cold box to separate H2 from CH_4). The entire process is heat (and cold) integrated to recover as much energy as possible. The heat required for the steam cracking is generated in the cracking furnaces where the generated CH_4 (and often H_2 when cracking ethane) from the cracking process is used as fuel to the burners. Combustion is done using air, and an excess amount of O_2 is required to ensure full combustion of the fuel.
This impacts the concentration of CO_2 in the flue gas. Therefore, and also depending on the excess of O_2, the following results for the flue gases (Source EPOS chemicals blueprint):



Note: GHG emissions for olefins in this figure represent that of the steam cracking process. Ammonia is presented on a different axis on the right.

Source: DECHEMA

Figure A.3.2. Global GHG emissions versus production volumes of top 18 large-volume chemicals, 2010. Source: ICCA (https://www.icca-chem.org/wp-content/uploads/2015/08/Energy-and-GHG-Reductions-in-the-Chemical-Industry-via-Catalytic-Processes-Technology-Roadmap.pdf)

- Composition (wt%):
  - O_2: 2-8
  - N_2: 73-74
  - CO_2: 8-11
  - H_2O: 9-13
- Temperature: 120 – 150°C (depending on overall efficiency)
- Pressure: 1 atm

The residual heat produced in the furnaces is recovered to produce high quality steam that can be used to drive the downstream separation processes and drive the main compressors of the process (cracked gas compressor, propylene refrigerant compressor, ethylene refrigerant compressor). Additional steam required in the chemical complexes comes from combustion of natural gas (and some waste streams) and air in steam boilers. The composition of the flue gas in these steam boilers is very similar across regions and similar to the combustion gasses in typical CHP plant producing electricity; fundamentally, they rely on the same combustion process to generate steam, followed by electricity production. And therefore, result in similar CO_2 concentrations in the flue gas. Figures A.3.3 and A.3.4 show schenatics of some chemical industry processes.

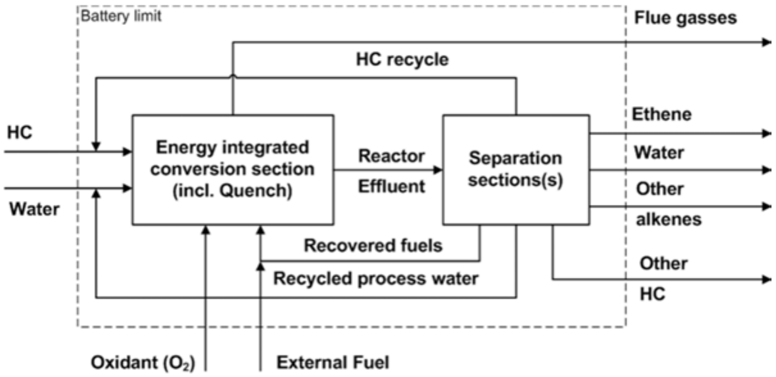


Figure A.3.3. Schematic of the ethylene process. From Van Goethem (2010)

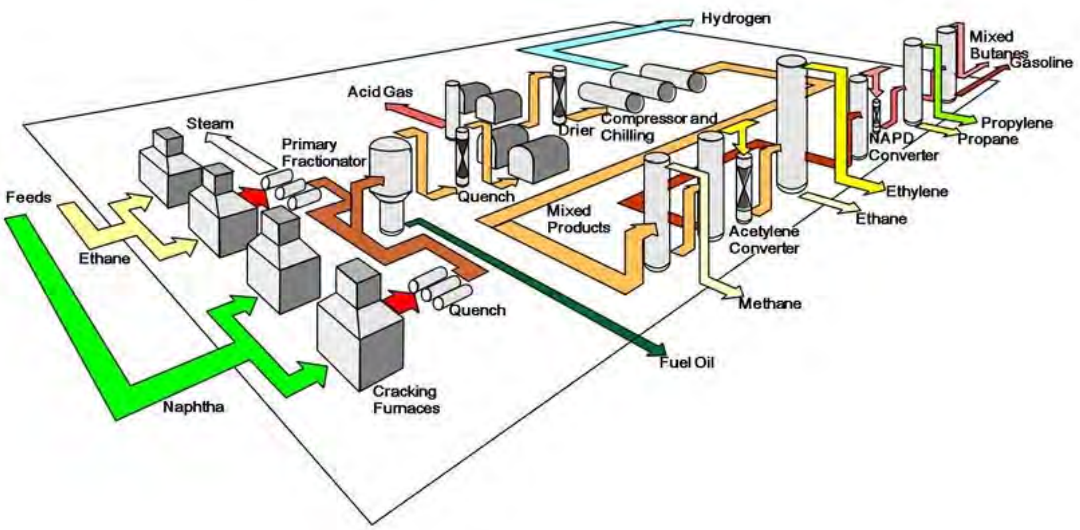


Figure A.3.4. Schematuc of an ethylene plant. From Van Goethem (2010)

Highly Concentrated source of CO_2 from Ethylene Oxide Production:
In ethylene oxide production, ethylene is partially reacted with O2 to generate ethylene oxide. The process is in fact a selective, partial combustion reaction of ethylene, and selectivity ranges from 70-90%, depending on the catalyst used. Carbon dioxide is the main by-product of the direct oxidation. A selectivity of 70–90 % would correspond to a maximal ratio of 0.86–0.22 tonnes of CO2 per tonne of EO produced in the reaction. The generated heat from the combustion process is again used to generate steam for the rest of the chemical complex, showing the high level of process integration in a typical chemical facility.

The result is a water saturated CO_2 stream, containing trace amounts of contaminants. The stream is purified and either liquefied by a downstream unit for marketing or released to atmosphere.

In Europe about 40% of production sites are marketing CO_2, which is a by-product of the production process. In Saudi Arabia, a capture and purification plant has been built in 2015 that has the capacity to purify up to 500.000 MT of CO_2 annually. This purified CO_2 is than used to produce methanol, urea or can be sold as liquid CO_2 for e.g. food and beverage applications. The purification exists out of a drying step, followed by compression step and contaminants removal (ppm ranges).[16]

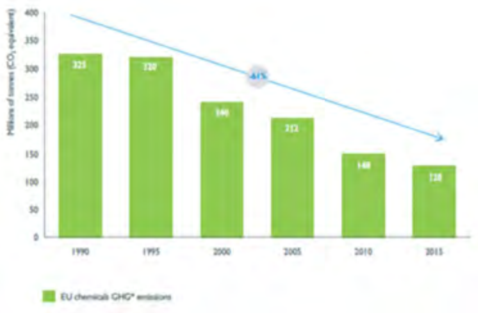
A.3.3. Non CCUS /non CCS technologies for reduction of CO_2 emissions in the chemical industry

In the past decades, the chemical industry has drastically reduced its energy intensity, through innovation, process improvements and further energy integration, reducing the amount of energy needed to produce the same product.

Long-term data gives evidence of the EU chemical industry, including pharmaceuticals, having a solid track record from 1990 to 2016 in reducing its greenhouse gas (GHG) emissions. According to the European Environmental Agency (EEA), the EU chemical industry, including pharmaceuticals, emitted a total of 126.0 million tonnes of CO_2 equivalent in 2016, down from a total of 325.1 million tonnes in 1990. This 61.2% decrease clearly illustrates how much importance the chemical industry attaches to reducing GHG emissions.

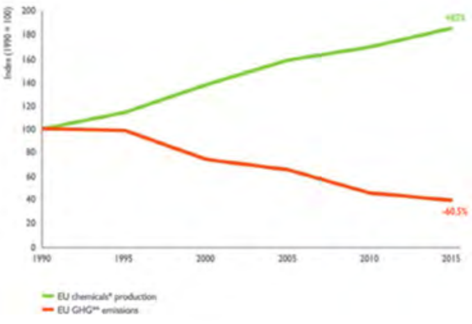
The Chemical industry's shift to less carbon-intensive energy sources has helped reduce GHG emissions. Much of the decline over the past 20 years is linked to abatement of nitrous oxide (N_2O), which has a higher global warming potential than carbon dioxide (CO_2) and is emitted by some chemical processes. The 59.5% decrease from 1991 until 2016 in total GHG emissions is even more remarkable given that, at the same time, production in the EU chemical industry, including pharmaceuticals, expanded by 83.0%.

Figure A.3.5 shows the reduction of total greenhouse gas emissions in the EU chemical industry from1990 to 2016.



Source: European Environment Agency (EEA)
*GHG = Greenhouse gas

Unless specified chemical industry excludes pharmaceuticals
Unless specified EU refers to EU 28



Source: European Environment Agency (EEA)
* Including pharmaceuticals
** GHG = Greenhouse gas

Unless specified chemical industry excludes pharmaceuticals
Unless specified EU refers to EU 28

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[16] https://www.cslforum.org/cslf/Projects/SABIC

Figure A.3.5. The reduction of total greenhouse gas emissions in the EU chemical industry from1990 t to 2016. Source: EAA and Cefic analysis 2018.

Further reduction of CO_2 emissions in the chemical industry/

This drive, to reduce the amount of energy via energy efficiency measurements remains as one of the main drivers in the chemical industry. Not only does it reduce associated CO2 emissions, it also reduces operational cost. However, energy efficiency alone will not be sufficient; several of the reactions unavoidably require energy to drive them (dictated by thermodynamics).

Further reduction of the footprint of the chemical industry and its wide variety of products can be achieved in particular through:

- Better utilisation of alternative carbon sources:
    - Biomass including biogeneous waste streams
    - CO_2 (and CO captured from industrial 'waste' gases) from industrial sources with and without H_2
    - Waste materials (including chemical recycling of plastics).
- Utilisation of low carbon energy sources, renewable electricity, unconventional energy forms, and H_2 with low carbon footprint.
- The integration of digital technologies from process design to production and logistics.

Bazannella et al. (2017) provides an analysis (based on technologies currently available) of the potential impact of the utilisation of low carbon energy and feedstock (CO_2 and biomass as alternative a feedsfock in the European chemical industry for the production of the main chemical building blocks used in upstream large volume production processes (i.e., ammonia, methanol, ethylene, propylene, chlorine and the aromatics benzene, toluene and xylene) that collectively represent two-thirds of the sector's current greenhouse gas (GHG) emissions. Their production through new low carbon processes is examined by considering further energy efficiency measures, the utilisation of alternative carbon feedstock (i.e. bio-based raw materials and CO_2) and electricity-based processes that can benefit from a progressive decarbonisation of the power sector. The penetration of these new technologies and processes are considered under four different scenarios with increasing levels of ambition, ranging from "business-as-usual" (no deployment of low carbon options nor energy efficiency measures) up to "maximum" (theoretical potential with full implementation of low-carbon technologies including efficiency measures). According to the "ambitious scenario" developed in this study, the implementation of the technologies investigated could lead to a CO_2 abatement of 101 Mt/y by 2050, i.e. a reduction of CO_2 emissions of 84% vs. Business as Usual Emissions in 2050. However, such transition to carbon neutrality will entail huge challenges for the chemical industry including investments in new assets that far exceed the typical level of investments in the recent years.

Currently the share of electricity in the energy mix is limited and the majority of energy used is by producing heat and steam to drive processes and equipment. Electrification of processes, combined with renewable energy can further reduce the CO_2 emissions from the chemical industry (scope 1 and 2)[17] further. For some equipment and processes, electric alternatives already exist (most rotating equipment like pumps and compressors). Others, like electric boilers are imminent, and other technologies, like electric crackers or reformers with very high emission avoidance potential are currently under development[18].

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[17] Scope 1 and scope 2 are as defined in the GHG reporting protocol…. Scope 1 emissions are direct emissions from owned or controlled sources (inside the fences). Scope 2 emissions are indirect emissions from the generation of purchased energy (e.g. purchased electrcity from the national electrcity grid). Scope 3 emissions are all indirect emissions (not included inscope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions. https://ghgprotocol.org/sites/default/files/standards_supporting/FAQ.pdf

[18] https://projecten.topsectorenergie.nl/storage/app/uploads/public/5b1/553/076/5b1553076ae1c420216728.pdf

A.3.4. CCUS in the chemicals industry

As described in the above paragraphs, the focus in the chemical industry has been on reducing energy consumption, thereby reducing the CO_2 emissions associated. Not only will it reduce the energy bill, but this approach will also reduce the amount of feedstock used for combustion and freeing them up for production of higher value materials. In addition, several of the above mentioned pathways will create additional markets for the chemical industry to supply its materials, like the renewable energy and storage industries.

However, there are limits to this approach as well. Some CO_2 streams in the chemical industry are unavoidable, for example some that are process related, or replacement with other solutions might be uneconomical for the near future.

The highest CO_2 concentration streams, like the CO_2 associated with the ethylene glycol process, are the most favourable streams for initial CO_2 capture; to capture the same volume of CO_2, less total volume needs to be processed in case the CO_2 is already concentrated. This will reduce the CAPEX involved typically in capturing and purifying the CO_2 stream. Technologies have also been developed to capture CO_2 from (low concentration) flue gases, and use the captured CO_2 either for storage or to use as feedstock. An example is the Econamine FG Plus^{TM} process developed by Fluor in combination with steam methane reforming (SMR), increasing the methanol production (Satish et al., 2014).

Most if not all examples where CO_2 is captured in the chemical industry are in combination with the utilization of CO_2. In this way CO_2 is turned into a valuable resource that can contribute to significant CO_2 emissions avoidance [19].

Several examples exist for instance for CCU, like the CO_2 purification and utilization plant in the Jubail industrial city in Saudi Arabia, where the CO_2 from the ethylene glycol process is captured and purified. The purified CO_2 is then injected in a CO_2 grid in Jubail that supplies other plants of SABIC to produce methanol or urea. Other examples are CO_2 EOR or using CO_2 for food and beverage applications.

The chemical industry is uniquely positioned to help develop and mature the utilization part of CCU. In addition, separation and purification of gasses are processes that are very common in the chemical industry. This makes the chemical industry also well positioned to help in maturing the capture technologies and purification processes.

A.3.5. Costs and Challenges

When discussing the challenges for CCU and CCS in the chemical industry, it is important to differentiate Utilization vs Sequestration and high concentrated CO_2 vs diluted CO_2.

For CCU in the chemical industry, if CO_2 capture can be coupled with a value creation step, through utilization, that will help accelerate deployment, as was shown for instance in the utilization project in Jubail. In this case, the emitter (ethylene glycol) is closely located to the user (methanol and urea plants, also located in Jubail). In addition, all the plants involved are SABIC plants. In most cases, the emitter and the potential user are from different companies or even industries, and are not situated close to each

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[19] Comparison of CO_2 emissions from the production of methanol CO2/renewable H2 vs conventional natural gas based production route, and subsequent olefins production according to the study from DECHEMA on *Low carbon energy and feedstock for the European chemical industry*, 2017 http://www.cefic.org/Documents/RESOURCES/Reports-and-Brochure/DECHEMA-Report-Low-carbon-energy-and-feedstock-for-the-chemical-industry.pdf :

- Methanol: -0.67tCO2 / t methanol from CO2/renewable H2 production vs +0.85tCO2 / methanol from conventional production route , i.e. Δ=1.52t CO2 avoided /t methanol
- Olefins: -1.13tCO2 / t olefin using methanol from CO2/renewable H2 production vs +0.76tCO2 / olefin from conventional production route , i.e. Δ=1.89t CO2 avoided /t Olefin

other. This requires for instance additional infrastructure that allows for the capture, purification and transportation of CO_2. Governments can, in combination with the industries, enable this infrastructure to be developed and used.

Using CO_2 as a feedstock for chemical or polymer production can also help in avoiding these CO_2 emissions. In some cases, CO_2 can be incorporated largely in the final polymer chain, allowing for maximum retention of the CO_2 molecule. In other instances, utilizing CO_2 will require the access to cheap and low carbon H_2. Governments can also play a role here in spurring these technology developments and help bring them to commercialization. This will increase the value of CO_2 as a feedstock, increase its utilization and reduce the emissions from these highly concentrated CO_2 streams.

When it comes to sequestration (CCS), some of the challenges for the chemical industry are:

- Multiple point CO_2 sources: In a chemical complex, there are multiple independent stacks emitting CO_2. Although the complex as a whole might be emitting significant amounts of CO_2, the economics of scale are not favourable for multiple smaller point sources compared to one large point source. A standard steam cracker complex has several stacks, i.e. several point sources of emissions. Typically there are several cracking furnaces (e.g. 5-15) as well as several auxiliary steam boilers, usually each with its own stack. As a result, this becomes a complex and expensive set-up to capture the flue gasses. In addition, introducing additional steps in the process can affect the throughput of the furnaces (additional pressure drop) or increase the CAPEX to convert from natural draft furnaces to forced draft (provided the additional weight can be supported by the existing structure and foundations.
- Lower concentrated CO_2 streams, for most of the emissions (e.g. typical combustion processes using air and natural gas to generate process heat, steam or electricity): the capturing step is a significant additional hurdle. Lower CO_2 concentrations mean that the equipment size to treat these streams becomes increasingly large, as almost 70% of the stream is inert N2 present in the air used for combustion. This poses great challenges for the economics for the capturing step..
  Potentially, a shift to use pure O_2 could be envisioned, avoiding the N_2 and resulting in higher CO_2 concentrations in the stacks, but this displaces the problem to the air separation units. These units can run on electricity, and thus leverage the decarbonisation strategies for power production (e.g. more use of renewables).
- Localisation: Criteria used to build chemical complexes are often access to good logistic (feedstock availability, access to harbor or in an industry hub bringing cross site and industry synergies), but CO_2 storage site potential has not been a consideration. In some instances, the chemcila sites might be closely located to good sequestration sites, but in many cases, the sites are far away for potential storage sites. This will require large infrastructure (pipelines) to transport from emitter site to storage site.

Government role could be in incentivising and developing infrastructure required to connect the emitters with potential CO_2 users of sequestration sites. In addition, it should incentives the technology developments to further increase the CO_2 utilization potential, which will require new process to generate low carbon H_2 as well as new processes and technologies to convert CO_2 into chemicals and/or polymers. Similar efforts are initiated through the Mission Innovation initiative, where one of the challenges identified is CCUS, with one pathway being the utilization of CO_2.

As ultimately additional cost would be incurred by implementing CCU strategies in the chemical industry, and the products from the industry are traded globally in a very competitive global market, it is important to consider carbon leakage risks. These additional costs could have the potential to put the regions and players implementing them (voluntarily or forced by regulations) in a disadvantage competitive position.

A.3.6. Conclusions

In conclusion, the petrochemical sector covers a wide range of products and processes, and as such also a wide range of CO_2 streams with different compositions. The first focus of the industry is to avoid the emissions by reducing the energy consumption and looking for alternative sources of low carbon energy sources or solutions. The majority of the CO_2 emissions is from diluted sources (combustion with air), and although the total emissions from a petrochemical complex can be significant, this is usually distributed over several point sources. This makes it a complex and expensive endeavor to capture the CO_2.

The cases where CCUS will make most sense in the industry will be on concentrated sources of CO_2, where the first approach will be to look for ways to utilize this CO_2, and turn it into valuable products or services.

Hence, the chemical industry can play a very important role in providing solutions to utilise CO_2 captured in this sector or in other industries and develop solutions for more sustainable capture and purification options. This will help the CCUS technologies to further mature, from which other industries could also benefit. This would require support from the public authorities (e.g. on infrastructure) as well as the development of interactions with the other industries.

A.4. The oil Refining industry

A.4.1. Present and future CO_2 emissions from oil refining

The sector is responsible of the 4% of the global CO_2 emissions, summing up approximately 1 billion tons of CO_2 per year[20]. Each refinery would use about 5.5-7.5% of feed as fuel, emitting between 0.8 and 4.2 million tons of CO_2 per year (for a 300,000 bpd size), depending on its complexity (van Straelen et al. 2009).

The two graphs in Figure A.4.1 show the evolution of European emissions from refineries under energy efficiency and fuel switching future scenarios and applying established and expected increase on the product quality, and demand. As seen in Figure A.4.1, CO_2 emissions from the refining sector are on an upward trend. The increase on energy efficiency can compensate at some extent the growth on demand and impact of product quality. However, CO_2 emissions would not show a so favourable output due to the “chemical” CO_2 produced and increase on the hydrogen intensity. Even considering a group of expected legislative changes, and under scenarios with higher energy efficiency, including fuel switching, or processing lighter crude oil (Table A.4.1), the CO_2 emissions rate will be increased over the years due to increased complexity as a result of a need for cleaner fuels (CONCAWE, 2008).

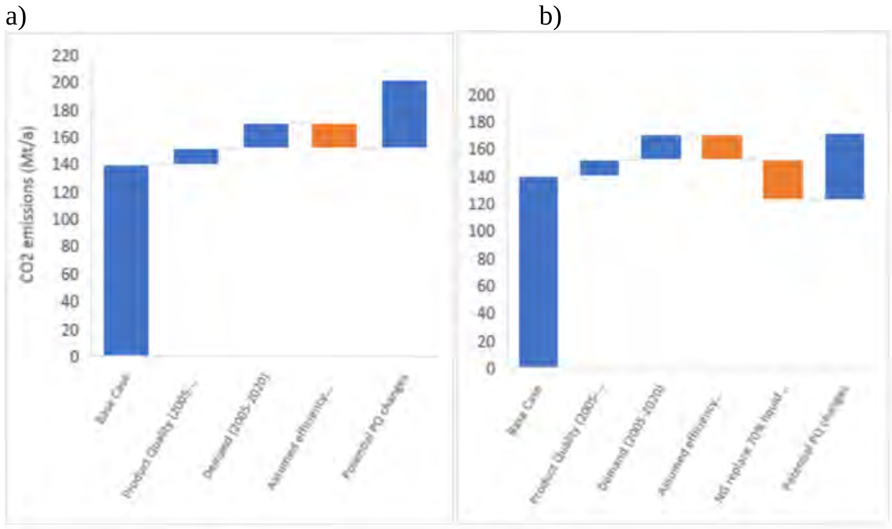

Figure A.4.1. CO_2 emissions (Mt/a) from European refineries and changes under (a) energy efficiency; and (b) fuel substitution scenarios (based on data from CONCAWE, 2008))

A.4.2. What are the sources of CO_2 emissions from the oil refining sector?

The oilrefining sector includes specific processes: distillation, conversion, reforming, desulphurisation and hydrogen production (conversion of the crude oil into intermediate and end-products).

Refining is an heterogeneous sector, as no two refineries are identical. Although they can share some common technology (for example, crude distillation, as see in Figure A.4.2), each site could take different route (UK Petroleum Industry Association, UKPIA, 2018).

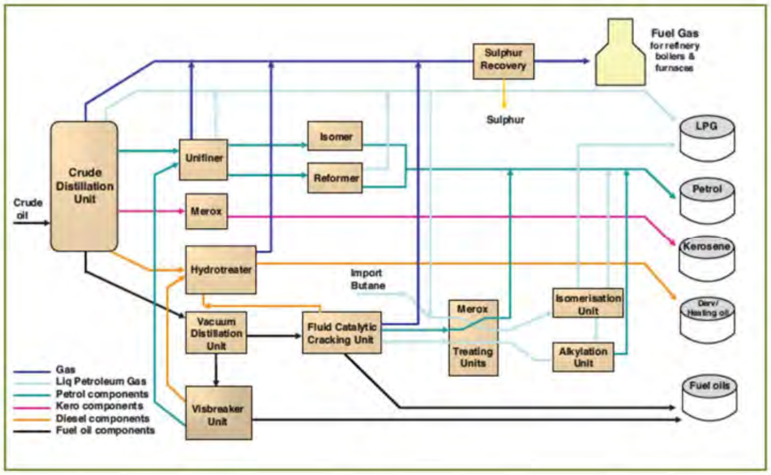

Figure A.4.2 Typical refinery processing units (BEIS, 2015; UKPIA, 2018)

A list of the main refineries configurations is described in Table A.4.1. About 70% of the production capacity in Europe work according to the second and sixth categories in Table A.4.1 (simple and complex configurations). In USA, the complete conversion category is the most used configuration.

Table A.4. 1 Types of crude oil processing refineries (Syrek and Rogowska, 2011)

Categories	Process diagram	Description

1. Simple	Topping	Including only atmospheric distillation unit
	Hydroskimming (HSK)	Producing chiefly heavy fuel oil. Light fuels are gasoline and diesel oil
2.and 3. Semi-complex	HSK+Fluidal catalytic cracking (FCC) + Vos breaking (VB) (2) or delayed coking (DC) (3)	The FCC increases production of gasoline by processing heavy fractions and remnants. The coke is removed in the catalyst regeneration process. The cracking gasoline requires hydro desulfurization.
4.and 5. Semi-complex	HSK+ Hydrocracking(HC) +VB (4) or DC (5)	The HC increases the production of gasoline and medium distillates. It is obtained good quality diesel
6. Complex	HSK+FCC+HC	Less gasoline is produced compared to the FCC + DC but more than in HCU + DC. In case of an additional installation IGCC all the remnants are processed. The only heavy product is asphalt.
7. Complete conversion	HSK + HC+ FCC +DC	DC is used for reducing the production of heavy combustion oil and increases production of fuel. Moreover, coke is produced.

The CO_2 volume emitted in refineries depends on several factors, mainly (Syrek and Rogowska, 2011):

- Type of feedstock
- Level of complexity of the process
- Type of refined fuels
- Production and use of energy
- Level of optimization of energy usage
- Application of biocomponent additives (if any).

Tables A.4.2 – A.4.5 show the differences on the CO_2 emissions stacks depending on different refineries configurations reported in IEAGHG (2017). As seen in the tables, the power plant/CHP is the main CO_2 emissions source. A description of contributions to CO_2 emissions without considering the power production can be found in Syrek and Rogowska (2011). Various refinery processes like fluid catalytic cracking, sulphur recovery plants, hydrogen generation units (such as SMR[21]) are also responsible of a large amount of CO_2 emissions, while fugitive emissions can be consequence of leaks from pressurized systems such as compressors, valves, or tanks (Choudhari, n.a.).

Table A.4.2 CO_2 emissions in Base Case 1 in IEAGHG (2017) (hydroskimming refinery, category 1 in Table A.4. 1 (Syrek and Rogowska, 2011), 100,000 BPSD)

Total emissions of the plant	**Crude Distillation Unit**	**Catalytic reforming**	**Vacuum distillation unit**	**Power Plant**	**Others (as 6 different stacks)**

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[21] See the Hydrogen section for further information

(tCO_2/h): 86.8					
CO_2 Emissions (tCO_2/h)	23.6	8.9	4	42.3	7.9
Share of the CO_2 emission of the plant (%)	27.2	10.3	4.6	48.8	0.7-3.5 (summing up 9.1)
CO_2 concentration v/v	0.113	0.084	0.113	0.084	8.4-11.3
Temperature (°C)	200-220	180-190	380-400	130-140	380-450

Table A.4.3. CO_2 emissions in Base Case 2 in IEAGHG (2017) (medium conversion refinery, categories 2-5 in Syrek and Rogowska (2011), 220,000 BPSD)

Total emissions of the plant (tCO_2/h): 257.5	**Power plant**	**Crude distillation units (if combined the two)**	**Fluid Catalytic Cracking**	**Steam reformer feed**	**Others (as 15 different stacks)**
CO_2 Emissions (tCO_2/h)	92.5	52	44.3	15.7	53
Share of the CO_2 emission of the plant (%)	35.9	20.2	17.2	6.1	0.3-3.8 (summing up 20.5)
CO_2 concentration v/v	0.083	0.113	0.166	0.242	0.083
Temperature	130-140	200-220	300-320	135-160	200-450

Table A.4.4. CO_2 emissions in Base Case 3 in IEAGHG (2017) (high conversion refinery, categories 6-7 in Table A.4.1 (Syrek and Rogowska, 2011), 220,000 BPSD)

Total emissions of the plant (tCO_2/h): 278	**Power Plant-HSRG+ Steam Boilers**	**Power Plant- Gas turbine**	**Fluid Catalytic Cracking**	**Crude Distillation Units (as 2 stacks)**	**Steam Reformer Feed**	**Others**
CO_2 Emissions (tCO_2/h)	54.21	25.02	53.1	52.3	67.3	26.07
Share of the CO_2 emission of the plant (%)	19.5	9	19.1	8.5-10.3 (summing up 18.8)	9.2	0.1-4.3 (summing up 9.3)
CO_2 concentration v/v	0.081	0.032	0.166	0.113	0.242	0.081-0.113
Temperature	115-140	115-140	300-320	200-220	135-160	200-450

Table A.4.5. CO_2 emissions in Base Case 4 in IEAGHG (2017) (high conversion refinery, categories 6-7 in Table A.4. 1 (Syrek and Rogowska, 2011) 350,000 BPSD)

Total emissions of the plant (tCO_2/h): 398.9	**Power Plant-HSRG+ Steam Boilers**	**Power Plant- Gas turbine**	**Fluid Catalytic Cracking**	**Crude Distillation Units (as 2 stacks)**	**Others (as 20 different stacks)**
CO_2 Emissions (tCO_2/h)	36.7	60.8	53.1	83.2 (41.6 each)	248.3
Share of the CO_2 emission of the plant (%)	9.2	15.3	13.3	20.8 (10.4 each)	0.2-4.6 (summing up 63.7)
CO_2 concentration v/v	0.081	0.0032	0.166	0.113	0.081-0.242
Temperature	115-140	115-140	300-320	200-220	180-450

As seen in the Table A.4.2 – A.4.5, the CO_2 emissions profiles change from one configuration to another. The CHP or power plant is the main CO_2 emissions source, except in the high conversion refinery configuration.

In addition, not only CO_2 is emitted during the refining process, but also methane, carbon monoxide, NO_x, and SO_x, which are also considered responsible of the global warming. The performance of the refineries depends on their configuration and complexity. As the complexity increases, the yield of naphta and gasoil fraction increases, as the heavy cuts are invested in more valuable products (IEAGHG, 2017). CO_2 emissions, consequently, also change from one case to another, and can be classified into:

- Direct Emissions, generally flares, incinerators, various process units of the refinery and fugitive losses. Those emissions are not only CO_2 but also SO_x, NO_x, H_2S, and N_2O
- Emissions from the fuel combustion, mainly CO_2, SO_x and NO_x.
- Emissions from utility generation units, generally boilers and/or CHP.

A.4.3. Non-CCS technologies for reduction of CO_2 emissions in the oil refining industry

As described in Choudari (n.a.) and Wanders (2017), the main alternatives to reduce CO_2 emissions are:

- Minimize Flaring and incineration
- Process improvements: Distillation is one of the most energy intensive operations where there is a great potential for CO_2 emissions reductions. The FCC unit can also be optimized through new designs (Wanders, 2017.)
- Modify fuel quality
- Use of carbon free electricity for the power and steam production
- Fuel switching. Biomass can be added to the blending unit at the end of the refining process or can replace the mineral feedstock (Wanders, n.a.)
- Regional integration, by heat/energy interactions with facilities nearby, or even through CO_2 utilization in other industries
- CCUS.

Those measures can be combined to optimize the cost of CO_2 reduction by using a multi-criteria assessment (technical, economical, societal and institutional), as in Wanders (n.a.). To note that there are not two refineries similar and the region will have a significant impact on the optimization of that emissions reduction.

Figure 2.4.3 includes the CONCAWE predictions in 2008 on the contribution of measures to reduce CO_2 emissions in refineries to 2020. Energy efficiency was seen as the first pathway to decrease CO_2 emissions, followed by fuel switching and substitution by natural gas. However, those measures were not enough to achieve the decarbonized scenario in 2020. For a typical refinery[6], increasing fuel efficiency could decrease the CO_2 emissions by approximately 10%, while fuel switching could reduce a 16% approximately, and using lighter crude oil would mean a 0.5% reduction. Still, the product quality requirements would increase the emissions in a higher rate than those measures. CCUS is key to cut down CO_2 emissions in the refining sector.

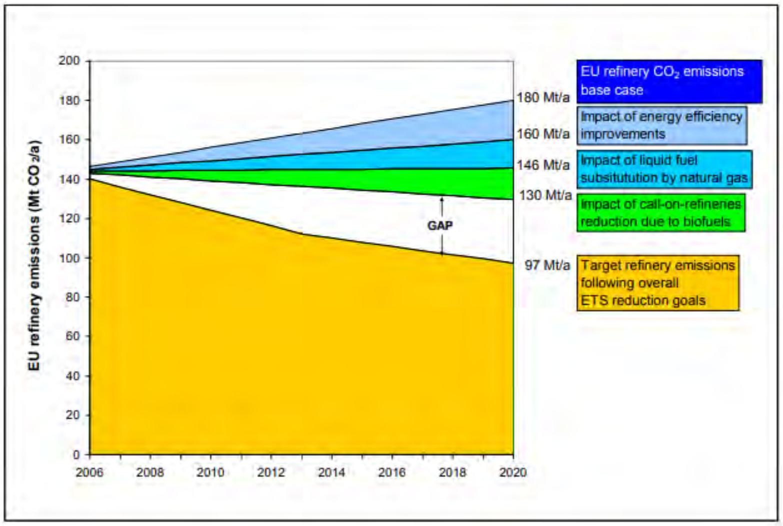

Figure 2.4.3. Contribution of measures to reduce CO_2 emissions in refineries (CONCAWE, 2008)

A.4.4. CCS in the oil refining industry

In general, three routes are recognized for CO_2 capture in refineries (van Straelen et al. 2009):

- Oxy-firing: It consists in using oxygen for combustion instead of air, resulting in a stream containing CO_2 and water. In refineries, that can be applied in the burners. The operation of fluid catalytic crackers on oxygen is another potential option
- Pre-combustion: As the name indicates, it takes place before the combustion, as a fuel pre-treatment, where CO_2 and H_2 are produced. In refineries, that can be applied on the gasifiers
- Post-combustion: It takes place as a post-treatment. As it does not need much process modification but just the installation of additional equipment, post-combustion is a very attractive option to treat one of several CO_2 stacks in refineries.

Chemical absorption, one type of post-combustion, is the most advanced CO_2 capture technology at the moment. Chemical absorption consists mainly in two process: absorption and desorption, both taking place in different columns (generally packed columns). The absorption takes place at relatively low temperature (40-80°C) in the first column (called absorber), where the gas is introduced through the bottom and the solvent is injected at the top. The CO_2 contained in the fluegas reacts with the solvent and stays in the liquid phase (now loaded), which leaves through the bottom, while the clean gas is emitted through the top. The loaded solvent is then sent to the desorber (also called stripper), where by heating at 100-140 °C, the gas is desorbed. There is an important energy penalty due to the large amount of energy required on the CO_2 desorption. In such scenario, as recommended in IEAGHG (2017), technologies, which do not depend on steam/energy (such as membranes or pre-combustion) could be beneficial to avoid such penalty. Additionally, the use of novel solvents with lower energy penalty could be a potential alternative. However, those are at a low development stage and there is not enough experience at large scale to provide accurate cost figures or operational experience.

There are a number of large CCS projects running nowadays in USA and Canada. Specifically, in the refining sector, Quest and Sturgeon projects (Canada) are using chemical absorption technologies to capture CO_2 and use for EOR. The Lake Charles Methanol (USA)[22] and the Teeside Collective (UK)[23] are examples of proposed large CCS projects. Moreover, several pilot plant campaigns are carried out in the TCM (Technology Centre in Mongstad, Norway) using fluegas from the FCC and the power plant.

A.4.5. Costs and challenges

The particularity of implementing CO_2 capture systems in refineries resides on the fact that there are several CO_2 stacks. Moreover, as seen in Tables A.4.2 – A.4.5, each refinery is different, and the CO_2 capture system design must be tailored accordingly. Chemical absorption, one of the post-combustion technologies, is advantageous as it does not need much integration with the refinery, becoming favourable for retrofitting cases. An optimum heat/energy integration with the industrial facilities is beneficial to reduce costs, as seen in IEAGHG (2018).

Although a full capture system could capture 90% of the total CO_2 emissions, it is important to optimize the capture rate based on the CO_2 avoidance cost, and complexity of the system (which will impact on the plant operation and required stop period for the installation of the CO_2 system) and which can be divided into technology and integration. As discussed before, post-combustion systems would require minimum integration with the refinery, as the CO_2 capture occurs after the oil production. However, the integration will be function of the CO_2 stacks to be treated, which will define the capture rate. Moreover, the fluegas from the different stacks needs to be pre-treated to minimize the sulphur content, which must be done collectively of individually as the CO_2 capture. All those decisions will impact on the kilometres of additional ducting required to collect the CO_2 and finding the space for that (van Straelen et al. 2009). Finally, that will influence on the final product cost and the CO_2 avoidance/capture cost.

As identified in BEIS (2015) for UK, the challenges for the decarbonisation of the oil refining sector can be summarized as follows:

- Market conditions
- Lack of focus on decarbonisation from the organization and management perspectives
- Regulations
- Energy costs
- Long payback
- Need of skilled staff
- Technical barriers for CCS
- Long lifespan of refineries
- Production disruption
- Technologies to achieve the decarbonisation scenarios might not be reliable yet.

Those challenges can be divided into three main barriers: lack of support, lack of business model, and technical risks due to lack of large demonstration projects. However, technical risks are now overcome due to the successful operation of the large projects operating at the moment. The cost of implementing CCS in refineries is difficult to estimate due to: a) the heterogeneity of this sector; b) the large number of possibilities to implement partial or full CO_2 capture and how it is done (for example, if all the fluegas is collected or different CO_2 capture units are installed, or the level of heat/power integration); and c) the significant influence of regional aspects.

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[22] Construction started in 2018. Expected to start running in 2020

[23] At proposal stage. Waiting for funding decisions

IEAGHG (2017) evaluated 16 CO_2 capture cases and reported a CO_2 avoidance cost of 160-210 \$/t CO_2[24]. Van Straelen (2009) reported a CO_2 capture cost 3-4 times higher than the carbon trading values[25].

The business model can be built around EOR, chemical sales, and government support (for example, through tax credits, CO_2 infrastructure, assuming management of risks, or financial support). However, those factors will be region and site-specific.

A.4.6. Conclusions

Refineries are an important source of CO_2 emissions. There are several measures available to reduce CO_2 emissions in refineries, perhaps those are not enough to reach the decarbonisation goals. CCUS, however, can tackle down dramatically the process emissions which otherwise would not be reduced. CO_2 capture technologies are ready to be implemented in the refining sector, perhaps due to the individual site-specifications, number of CO_2 stacks and costs associated, the configuration and business case must be tailored accordingly.

A.5. Hydrogen Production

A.5.1. Present and future CO_2 emission from hydrogen production

Hydrogen is used in several parts of the chemical industry, in particular the production of ammonia and methanol but also in refining. It is treated separately here because of its present and anticipated future (importance. Therefore, emission numbers from hydrogen production cannot be simply added to those from the other EIIs.

Emissions from today's hydrogen production of approximately 60 Mt/year are around 500 Mt/year, with an assumed CO_2 intensity of 8.5 kg CO_2/kg H_2 (Jakobsen and Åtland, 2016). If the 10-12 fold increase should be delivered by the same fraction of fossil fuel based hydrogen (96%), the unabated CO_2 emissions from the production will be more than 4.5 Gt/year.

If electrolysis takes over a substantial part of the hydrogen production, there will still be significant CO_2 emissions if the electricity is produced with fossil fuels, without CCS. The theoretical minimum CO_2 intensity for electrolysis using power from fossil fuels is greater than the actual intensity for steam methane reforming (SMR)-based hydrogen plants by a factor of two. These emissions and their mitigation are considered to belong under power and CCS and fall outside the scope of this task force.

A.5.2. What are the sources of CO_2 emissions from hydrogen production?

There are several processes for producing hydrogen from fossil fuel or biomass feedstocks, all involving syngas production followed by separation of H_2 from CO_2. The syngas production approaches include steam methane reforming (SMR, most common for natural gas), partial oxidation (POX, most common for liquids like oil), auto-thermal reforming (ATR, a combination of non-catalytix POX and SMR), and gasification (used for solid fuels like coal and biomass). Technology selection depends on economics, plant flexibility and feedstock source. A schematic of hydrogen production from fossil fuels is shown in Figure A.5.1.

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[24] To note that those figures are higher than the values reported in the literature due to : a) costs of interconnections were included; b)it was assumed that a new CHP, cooling water towers and waste water plant were built; and c)the cases including small and medium CO_2 emission point sources and/or low to medium fluegas CO_2 content (further information is included in IEAGHG (2017))

[25] To note than in 2009 the price of CO_2 in the trade system crashed. As there is not a quantitative figure in this paper, it is difficult to update this price to 2019

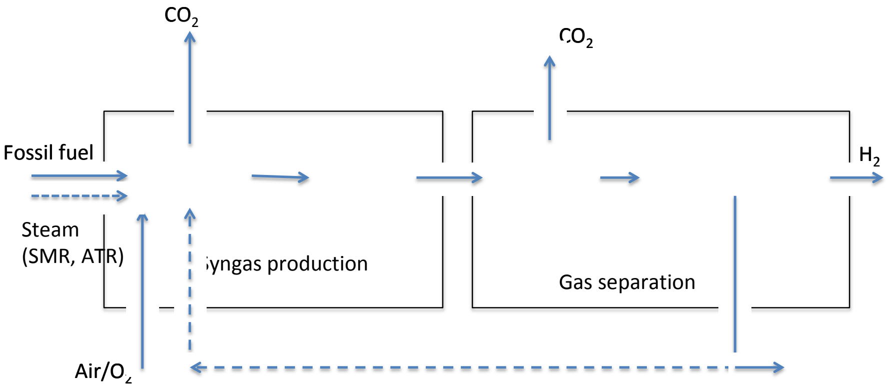

Figure A.5.1. A) Schematic of hydrogen production from fossil fuels (after Voldsund ate al., 2016).

The most common approach to hydrogen production is by SMR, which is an endothermic process in which natural gas (methane) reacts with steam with heat provided by burning fuel in a furnace, i.e. the reactor is externally heated. This combustion will generate CO_2. The reforming process creates a syngas with H_2 and CO, and the CO is further reacted with steam in an exothermic process called water –gas shift (WGS), resulting in a process gas consisting of CO_2 and H_2. These gases have to be separated for hydrogen production. The most common method for the separation is pressure swing adsorption (PSA). Here, the gas is sent through an adsorbent that adsorbs the CO_2 and impurities at high pressure, while the overwhelming part to the H_2 passes through. When the adsorbent is saturated with CO_2, the pressure is reduced and CO_2 released.

CO_2 emissions depend on the feedstocks and the technology. As natural gas in SMR is currently the dominant method for H_2 production, this approach will be used to illustrate the CO_2 sources.

SMR is a mature technology. CO_2 emissions from H_2 generation based on natural gas reforming producing 2.85 million Sm^3/d or 256 tonne/d of H_2) are summarized in Table A.5.1 below (Bonaquist, 2010). Properties of the CO_2 emissions are shown in Figure A.5.2.

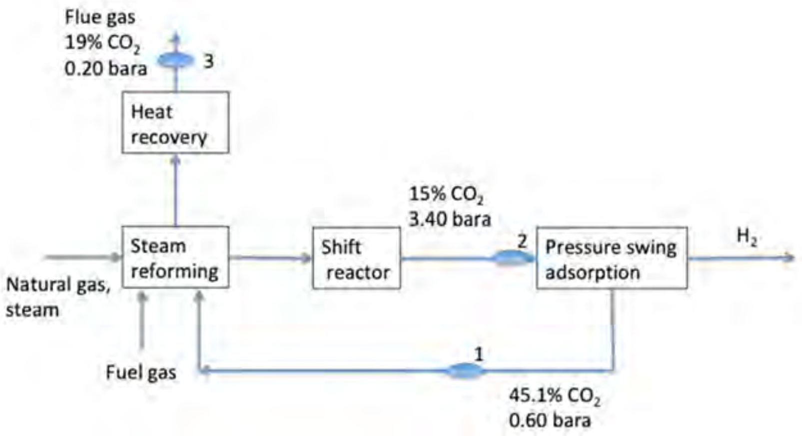

Figure A.5.2 Streams of CO_2 in a SMR plant of Table 1, with CO_2 concentrations and partial pressures (After Bonaquist, 2010). Points 1, 2 and 3 mark possible locations for CO_2 capture.

Table A.5.1.Feedstock and emissions from a hydrogen plant with capacity 256 t H_2/day. (After Bonaquist, 2010).

Source	**CO_2 emitted (metric tonnes per day)**
Complete conversion of feed to H_2	**1345**

Combustion of fuel to provide reforming energy	**380**
Combustion of fuel to provide export stream	**263**
Power for separation and compression	**9**
Total emissions (theoretical minimum)	**2000**
Actual emissions	**2270**

The CO_2 intensity of H_2 production in Table A.5.1, 8.8 t CO_2/t H_2 is somewhat higher than indicated in a life cycle analysis by the US Department of Energy (DoE, 2006), where it is given to be 7.2 t CO_2/t H_2 H_2 from the reforming process, Here we use the average, 8.5 t CO_2/t H_2 from Jakobsen and Åtland (2016).

The POX technique for producing hydrogen differs from the SMR process in the first step, which in POX consists of partial combustion of the fuel with a sub-stoichiometric amount of air or pure oxygen in the reformer. The products from this exothermic reaction are carbon monoxide and hydrogen. After this partial combustion, the process is as for SMR. POX can be performed with as well as without catalyst.

The ATR process is a combination of SMR and POX in one reactor, and it is similar to SMR after the first step. Inside the ATR, natural gas reacts with steam to provide syngas, as in the SMR process, and in addition, parts of the fuel react with oxygen. A benefit of ATR is that the heat generated by the POX reaction is used by the endothermic SMR reaction.

A review of reforming and electrolysis technologies for hydrogen production including techno-economic analysis can be found in Jakobsen and Åtland (2016) and in a report by H21 North of England (2018). Mission Innovation (2018) points to microchannel reactors as another possible avenue for hydrogen production through reforming.

The conversion efficiencies in terms of mole H_2/mole natural gas is higher for SMR than for POX and ATR, one factor that contributes to making SMR the lowest cost large scale technology for hydrogen production. Plant energy efficiencies are approximately similar for SMR and ATR (Jakobsen and Åtland, 2016; H21, 2018) and slightly lower for POX. The CO_2 emissions per produced hydrogen unit are 8.5 t CO_2/t H_2 for SMR, 8,6 t CO_2/t H_2 for POX and 8.3 t CO_2/t H_2 for ATR according to Jakobsen and Åtland, 2016), all based on natural gas as feedstock.

Table A.5.2 shows the CO_2 concentration in reformer and process gases for the SMR. ATR and POX.

While natural gas is the dominant fuel for H_2 production globally, coal is the dominant fuel in China. In China, hydrogen is produced from coal mainly by two methods: carbonization and gasification. After years of technology advancements, gasification has become the preferred technology for coal intensive processing. When hydrogen is produced by POX using coal gasification, the amount of CO_2 emissions would be doubled compared to SMR with natural gas.

Table A.5.2. Characteristics of CO_2 emissions from the different facilities hydrogen plant plant

	Facility				
	SMR		**ATR**	**POX**	
	Reformer flue gas	**CO_2 separation**	**CO_2 separation**	**Reformer flue gas**	**CO_2 separation**
CO_2 concentration, %	19	45	40	3-10 (wet basis)	25-35 (wet basis)

A.5.3. Non-CCS technologies for reducing and eliminating CO_2 emissions in hydrogen production

The alternative to SMR for hydrogen in the middle to long timeframe is water splitting by electrolysis. This approach will reduce the current associated GHG emissions only if the electricity is sufficiently low-carbon. Considering that direct emissions of hydrogen produced via an SMR – natural gas process without CCS is 8.5 kg CO_{2e}/Kg H_2 and water electrolysis yield is 1kg H_2/50 kWh (electricity) the GHG (Green House gases) content of the electricity must be below 170 g CO_{2e}/kWh to start having a positive impact on the GHG footprint of H_2 (SMR nat gas route - without CCS). As a comparison, currently in Europe, the only countries' electricity mixes well below this value are France, Norway, Sweden and Denmark.

CCS can remove 90% or more of SMR direct emissions, so the same calculation lead to a carbon content for electricity 20 g CO_{2e}/kWh to start having an impact equivalent to CCS on current SMR natural gas production processes. From Ecoinvent v3.3 database, windmill or Photovoltaic (PV) electricity have often carbon footprints between 10 – 20 g CO_{2e}/kWh (windmill) and 50 – 150 g CO_{2e}/kWh (PV). Note these numbers represent only "inside fence" numbers and do not include a full life cycle analysis. A gas fired power station with CCS will have a carbon footprint of 30 – 40 g CO_{2e}/ kWh and a coal fired power station with CCS approximately the double of this (ZEP, 2017; Bazzanella and Ausfelder, 2017); and, more indirectly, the European Chemical Industry Council, CEFIC, conclude that use of hydrogen from electrolysis, will be highly challenging with renewable electricity only, not counting for other applications of hydrogen. Even with the most efficient electrolysis the electricity demand will be hard to meet. This can be illustrated by using the extreme case by the Hydrogen Council (2017). If 550 Mt H_2/year is to be produced by electrolysis and the power is obtained from renewables the hydrogen production will be without CO_2 emissions, but will require electricity input of around 26 000 TWh. This is more than the global electricity production from all sources in 2014 and 75 – 80 % of the expected electricity generated from renewable energy sources (nuclear excluded) in the B2DS by 2050 (IEA, 2017). With a hydrogen demand that is 60% of the predictions of the Hydrogen Council the need for renewable electricity to produce hydrogen will still be challenging.

Alkaline electrolysis is the state-of-the-art electrolysis technology. It requires a 20-40 % solution of KOH and electrodes coated with Ni as catalyst. The energy requirement of this technology is about 48kWh/kg H_2. Alkaline electrolysers have a CAPEX of 1000 – 1200 €/kW (Bazzanella and Ausfelder, 2017). Emerging solutions include:

- Proton-exchange-membrane (PEM), which can operate on pure water and is very compact and can be designed for pressure up to 100 bar. The current system cost for PEM is about twice that of alkaline systems but expected to drop (Bazzanella and Ausfelder, 2017).
- Solid oxide electrolysis (SOE). If the electrolysis could be operated at temperatures in the range 700 – 1000 ^oC, the electricity demand could be reduced to below 30 kWh/kg H_2. This technology is present at Technology Readiness Level (TRL) 6-7. The technology is most likely to find application where high-temperature heat sources are available.

Using biomass as feedstock and even fuel for the reformer may be a low-carbon option without CCS provided the biomass is grown and harvested sustainably. The biomass will have to be converted to syngas by gasified before entering the water-gas shift step.

A.5.4. CCS technologies for reduction of CO_2 emissions form hydrogen production

Separating CO_2 from the reformer process gas is mature technology. At least seven plants are presently capturing CO_2 from hydrogen production:

- Quest, Alberta, Canada (see Section A.7.4)
- Port Arthur, Texas, USA, demonstrating a state-of-the-art system to concentrate CO_2 from steam methane reforming (SMR) hydrogen production plants. CO_2 is used for EOR

- Tomokomai, Japan. Amine scrubbing of PSA off-gas in hydrogen plant, CO_2 to offshore geologic storage
- Air Liquide operates the Port Jérôme Project in France where 100k tons CO_2/year of food-grade CO_2 is captured from an SMR H2 plant.
- Three in China:
    - Coal indirect liquefaction plant in Erdos, Xinjang. 100 000 tons CO_2/year captured and injected in saline formation
    - Refinery: Sinopec Maoming Petrochemical Company: 100 000 tons CO_2/year captured and used in food industry
    - Lihuayi Group Co, Ltd. Heavy oil and hydrogenation project. CO2 partially used for polycarbonate synthesis.

In hydrogen production CO_2 is separated from the H_2 as part of the process. This CO_2 is very clean and, after compression, ready for transport to a storage site (or slip streams can be used for other applications).

Alternatives exist to PSA, for example absorption process using liquid solvents like amines. These processes can be applied to the reformer flue gas as well, with removal efficiency of about 90%, as the reformer flue gas will be very similar to flue gases from fossil fuel power plants, where solvent absorption is proven technology at commercial scale. Cryogenic and low-temperature separation may also be options but not as far developed as solvent based absorption. For a review of CO2 capture process in hydrogen production, see e.g. Voldsund et al. (2016) and IEAGH (2017).

CO_2 can be captured from all or any of the three streams with removal efficiency of about 90% from tail gas and from steam reformer flue gas using pressure swing absorption (PSA), and up to 100% from raw H_2 at higher pressure. However, in the example in Figure A.5.2, the gas stream from the gas separation (here PSA) is transferred back the stack from the SMR unit.

Adsorbents can be used to selectively remove one or more of the products formed in hydrogen production. The process called sorption-enhanced reforming uses adsorbents to selectively remove one or more of the products formed in the equilibrium-limited reactions used in hydrogen production, shifting the equilibrium and obtaining higher conversion at milder thermal conditions. In SEWGS the shift reaction is carried out while CO_2 is continuously being removed and in sorption-enhanced SMR the SMR and WGS reactions are carried out simultaneously while CO_2 is being removed. Both options are in erly stages of development (Meyer et al., 2011; Voldsund et al., 2016). Challenges are connected to material properties of the sorbent, like mechanical stability, adsorption capacity, reaction kinetics and regeneration heat. (Progress is being made, Di Giulio, ZEG Power, personal communication in connection with milestone reporting to the Research Council of Norway, June 2018).

In SMR about 70% of the CO_2 is generated in the process gas, whereas in POX and ATR the number is more than 90%. This is beneficial to the capture process, which could, along with technology improvements make POX and ATR attractive hydrogen reforming technology (see also chapter on fertilizer industry) without employing other capture technology than the commercial technology supplied as part of the total ammonia plant. However, a challenge with POX/ gasification of coal is that the CO_2 volumes are significantly higher than for natural gas processing, which makes it necessary to scale up CO_2 handling correspondingly.

Membranes are barriers that selectively let certain gas components pass through more easily than others, thus dividing the feed stream into two streams. In hydrogen production, membranes can serve at least two purposes:

1. In a WGS reactor, where membranes can replace the PSA unit. A schematic is show in Figure A.5.3, where hydrogen is selectively removed from the syngas and CO_2 and H_2O exit the reactor. The steam is easily removed by condensation. Continuously removing the hydrogen with a sweep gas, higher conversion rates at higher temperatures can be achieved. This technology is presently being demonstrated at a methanol plant at Tjeldbergodden, Norway using palladium (Pd) membranes (Peters et al. 2017). The potential for cost reductions are promising (Reinertsen, 2018)

2. In a SMR membrane reactor, in which the SMR, WGS and H_2 purification steps are combined, Figure A.5.4. Both metallic (Pd) and ceramic membranes are considered for this purpose.

Hollow fiber membranes have also reached technology readiness level >5 but many other membrane technologies are still at testing at laboratory scale (Voldsund et al., 2016),.

For reviews of membranes and membrane systems in hydrogen production, see. for example Gallucci et al. (2013) and Voldsund et al. (2016).

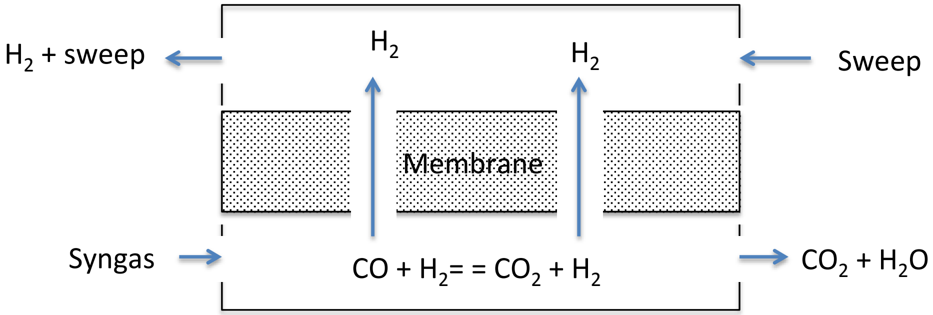

Figure A.5.3. Schematic of WGS-membrane reformer (after Voldsund etal., 206)

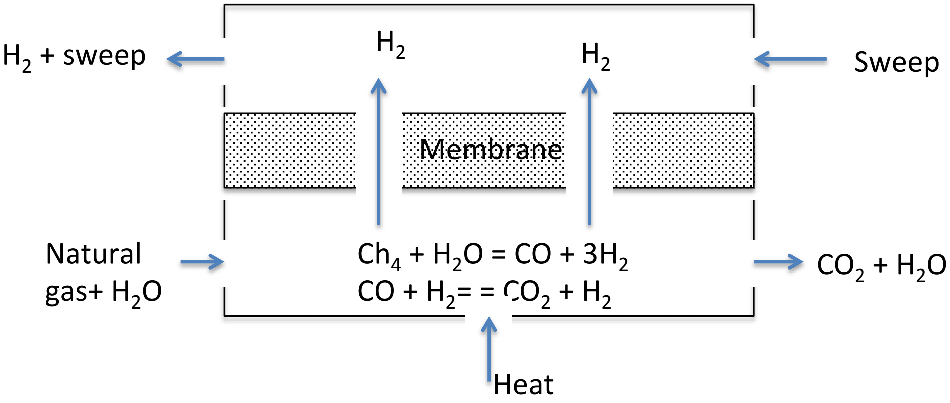

Figure A.5.4. Schematic of SMR membrane reformer (after Voldsund etal., 206)

Table A.5.2 summarises the abatement potential with respect to CO_2 emissions for application of CCS to the reformer flue gas and for some emerging CO_2 capture technologies.

A.5.5. Costs and challenges

Estimating cost of hydrogen depends on several assumptions and direct comparisons will not always be possible. Amongst the factors influencing the levelised cost are expected lifetime of plant, cost of feedstock and other inputs, discount rate, scale of facilities and production, time of comparison, location, and whether one considers commercial or industrial applications. For SMR the price of natural gas will be important, and it varies with time and region. For electrolysis the price of electricity will be a significant parameter that also has temporal and spatial variations.

Table A.5.2. CO2 abatement potential by application of CCS to the reformer flue sas and for some emerging CO_2 capture technologies

Facility/ Process	Most advanced/	Potential for CO_2 reduction by CCS	Challenges	Status of development/expected deployment	Source

	promising capture technology	**(from baseline integrated), %**			
Reformer flue gas	**Post-combustion,** **absorption, e.g. amines or chilled or activated ammonia; adsorption: membranes**	**10-25**	**High cost, lack of business and policy incentives**	**Mature technologies, storage sites located and characterise only in few places**	
Reformer process gas	**Already captured as part of hydrogen process;**	**70-90**	**For CCS, general lack of** - **infrastructure for transport and storage** - **business and policy incentives**	**Used for EOR in two plants in USA, i.e. with business incentive**	
Reformer process gas	**Membranes in WGS;** **may give significant cost reduction**	**70-90**	**Material cost cost; fabrication reproducibility; mechanical nd chemical stability.** **Long term and large scale experience; Infrastructure business incentives for CCS**	**Demonstration with palladium (Pd) mebranes at methanol plant at Tjeldbergodden, Norway**	
Reformer process gas	**Sorption-emhanced hydrogen production**	**70-90**	**Material properties of the sorbent (like mechanical stability, adsorption capacity, reaction kinetics and regeneration heat)**	**Low TRL (3-4)**	

Reformer process gas	**SMR membrane reactor**	**>90**	**Technology development to reach TRL 5-6**	**Only at lab scale**	

If CCS is combined with biomass (feedstock and/orfuel switching), negative emissions may be achieved.

Bonner (2013) presented some relative numbers for hydrogen production, using IEA 2013 Energy Outlook as reference for feedstock. In industrial settings the cost for SMR was found to be about US\$ 1.0/kg H_2 and around US\$ 4/kg H_2 for electrolysis. Others give different costs but of the same order and with approximately the same ratio between SMR and electrolysis. Bazzanella and Ausfelder (2017) give SMR costs at 1- 4 €/kg H_2 and electrolysis costs 1.7 – 4.5 €/kg H_2 for alkaline electrolysis and 2.8 – 5.7 for proton-exchange-membrane (PEM) electrolysis. The ranges are due to different energy costs, which are the same for SMR and electrolysis.

Fraile et al. (2015) cites US Department of Energy on SMR 2010 prices between 1.21 and 2.03 US\$/kg H_2, for scenarios with a range of gas prices, and James et al (2016) indicate hydrogen production cost by PEM and Solid Oxide Electrolysis Cell (SOEC) electrolysis from 3.8 US\$/kg H_2 to 5.1 US\$/kg H_2, whereas cost for hydrogen production by reformation of natural gas in a reformer-electrolyzer-purifier may be as low as 2.6 – 3.7 US\$/kg H_2.

ZEP (2017) indicates present SMR cost at slightly below 2 €/kg H_2 and electrolysis cost at 4-5 €/kg H_2, both depending on energy feedstock costs. Introducing CCS will increase SMR hydrogen cost by 25-50%. However, as carbon prices increase SMR with CCS will become competitive with SMR without CCS. By 2045 -2050 they may both be around 3.5 €/kg H_2. At that time, H_2 production by electrolysis may be down to around 3.0 €/kg H_2.

Finally, IEAGHG (2017) gave a base case levelised cost of hydrogen at 1.4 €/kg. CCUS would add 18 – 33 % to this, giving levelised cost of hydrogen at 1.65 – 2.0 €/kg.

In addition to the added cost for hydrogen production with CO_2 capture there are challenges connected to lack of infrastructure for transport and storage of the CO_2, as well as lack of business incentives and models for cost and risk sharing.

A.5.6. Conclusions

The needed reductions of CO_2 emissions from the hydrogen industry are unlikely to be achievable using electrolysis with renewable electricity sources only, at least in the short to medium term. CCS technologies applied to hydrogen production by reforming exist and are in operation. They are able to reduce CO_2 emissions by 90 %, or more, sufficient to achieve significant reduction in CO_2 emissions in a near term. As a conclusion,

- CCS seems a competitive and efficient mean to decarbonize H2 production compared with low/free carbon electrolysis
- As the technologies are available at industrial scale, it can allow to increase very soon the decarbonization of the sectors using these processes

Thus, achieving deep cuts in CO_2 emissions from hydrogen production, assuming a 5- 12 fold increase in hydrogen demand over the next 35 years or so, will most likely require the implementation of a combination of electrolysis technologies using renewable electricity as feed-stock and reforming of fossil fuels with CCS. The technologies are here, but non-technical obstacles, such as cost and lack of business models, must be overcome.

Challenges that must be overcome are common with all CCS projects and include:

- Availability of infrastructures like transportation (by boat or pipelines) and geological storages

- Associated business models/fundings and taxes schemes for large diffusion. Indeed some projects (with application of CO_2 for EOR, food grade CO_2) have already existing business models.

A.6. Natural gas production and conversion to LNG

A.6.1. Present and future CO_2 emission from natural gas production

Natural gas is a mixture of gases. It is typically at least 90% methane, plus other hydrocarbons such as ethane and propane. Natural gas often also contains gases such as nitrogen, oxygen, carbon dioxide and sulphur compounds and water. Naturla gas containing small volumes of these impurities can still be used as fuel, but natural gas with high volumes of impurities cannot be burned efficiently and safely. An example is the natural gas produced at the Sleipner Field in the North Sea. This gas contains unusually high levels (about 9%) of CO_2, but customers want CO_2 levels less than 2.5%. A special processing platform, Sleipner-T, has been built to separate CO_2 from the natural gas.

If natural gas contains significant levels of impurities, additional treatments must be applied to remove them. Natural gas reservoirs containing significant quantities of CO_2 and hydrogen sulphide (H_2S) are termed sour gas reservoirs or acid gas reservoirs if CO_2 predominates. According to (Global CCS Institute 2018), more than 40% of the world's gas reserves are sour, with the number increasing to 60% for Middle Eastern gas reserves. Sour and acid natural gas must be "sweetened" before use. A typical on shore natural gas sweetening process is shown in Figure A.6.1.

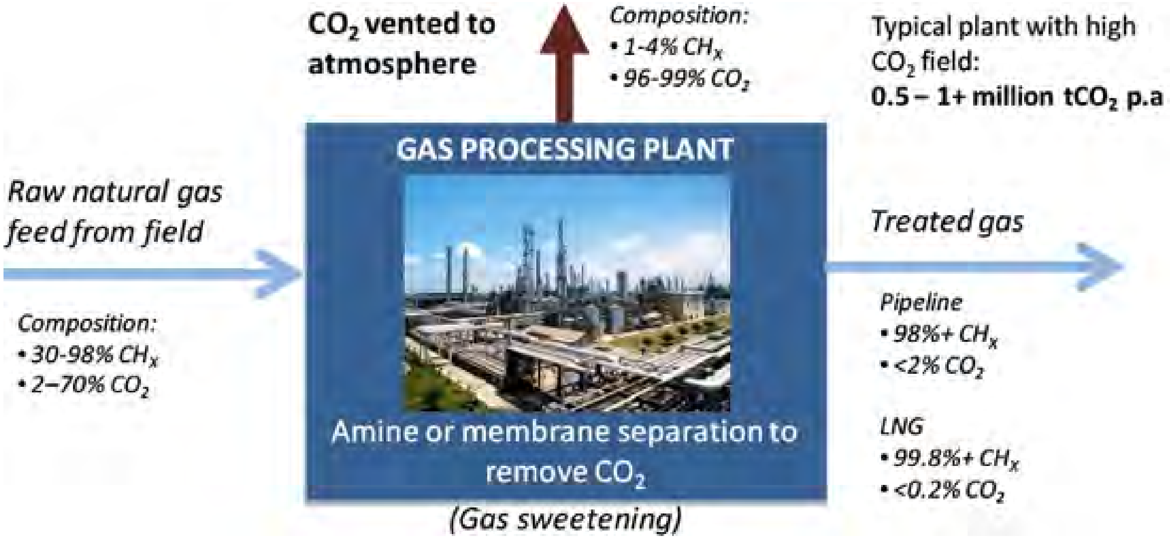

Figure A.6.1. Natural gas sweetening configuration (Global CCS Institute 2018)

H_2S must be removed to trace levels from natural gas because it is highly corrosive when mixed with water and toxic to biological organisms. For CO_2, the level of removal will vary depending on delivery route and end use. For pipeline gas, this will be determined by the gas network operator through a contracted delivery specification for the gas, which in turn depends on the level of blending that may be achieved. For some dedicated applications, these standards may be relaxed where low calorific value (LCV) gas can be combusted (e.g. for use in modified gas turbines). Consequently, specifications for pipeline gas will vary from 0.2% to up to 18% or 20% CO_2 by volume, however, typical specification for gas distribution grids are for less than 2% CO_2 by volume.

A.6.2. What are the sources of CO_2 emissions form natural gas production and liquefaction?

Typical CO_2 emission rate from the current compressed natural gas production is ~2-3 kg/GJ. This emission rate includes typical native CO_2 in the reservoirs and emissions associated with exploration and extraction, such as flaring, power required for compression and for the gas processing plant operations. Obviously, the emission rate can change due to the variations in the native CO_2 concentration in the gas reservoir, as shown in Table A.6.1. The emission rate for liquefied natural gas (LNG) production is significantly higher at 4.4-5.9 kg CO_2/MJ. Considering the potential advancements in CCS and energy efficiencies for both processes in the next decades, we assumed a combined CO_2 emission rate of 3 kg/GJ for all natural gas production by 2050.

Table A.6.1. CO_2 content in natural gas reserves (**Shimekit et al. 2012**)**:**

Location	**Gorgon (Australia)**	**New Albany shale gas (United States)**	**Barnett shale gas (United States)**	**Sleipner (Norway)**	**Snøhvit (Norway)**
CO2 content in %	14-16	5.6-10.4	0.3-2.7	9	5

GHG emissions from natural gas production vary according to these sources, as well as the production and treatment technologies. However, this report focuses on the potential role of CCUS to reduce CO_2 emissions. Thus, only CO_2 emissions will be considered, both the CO_2 contained in the natural gas in the reservoir and its emissions from the production and export facilities.

Compressed natural gas

In many natural gas reserves CO_2 is the largest contaminant and must be removed from natural gas prior to its transportation for economic reasons to reach the sales specifications and also for corrosion prevention. In the US, CO_2 in the pipeline cannot exceed 2 mol%. With the focus on reducing GHG emissions, the simple removal of CO_2 from the raw natural gas must be followed by its capture and sequestration.

Table A.6.2 shows the CO_2 emissions from the emission sources of a typical natural gas reserve production facility. “Large individual single points” consists of CO_2 from fuel consumption, “Scattered” consists of CO_2 from flare combustion, “From process” consists of CO_2 in raw gas, which will vary depending on the source of the natural gas.

Table A.6.2. Emissions from a typical natural gas reserve, numbers can change depending on the gas the gas reserves

CO2 emissions	**From combustion of fossil fuels**		**From process**	**Fugitive (if available)**	**Total CO2 emissions**
	Large individual single points (>>0.1 Mt/year/point)	**Scattered (if available)**			
Industry emissions (kgCO2/GJ)	0.55	0.15	1.72 (varies from reservoir to reservoir		2.42

Table A.6.2 shows that, once CO_2 is removed from the raw natural gas, most of the CO_2 emissions are from fuel combustion in connection with compressors. There are also some CO_2 emissions from the CO_2 removal process itself and some other minor contributors. On the other hand, GHG emissions from the shale gas are slightly lower than conventional natural gas production (Burnham et al. 2012). Since methane emissions are much higher in shale gas production than in conventional gas production

(Howarth et al. 2011), this finding implies that CO_2 emissions in shale gas production must be quite a bit lower than in conventional gas production.

LNG production

LNG is an alternative way to transport natural gas. It is obtained when natural gas is cooled until its bubble point (or even below) at atmospheric pressure, which corresponds to -162°C. Global annual LNG production capacity stood at 340 Mt in 2017, with 879 Mt/year new LNG proposals pending (International gas Union, IGU 2017). If all these proposed LNG capacity is realized, global LNG production would be at 1219 Mt/year by 2050. For a more modest growth rate of 2% per year, the global LNG capacity would be about 620 Mt/year by 2050.

Prior to the liquefaction process, CO_2 must be removed from the raw gas to prevent CO_2 solidifying during compression (i.e. dry-ice formation), which has serious implications for process control. Typical specification for LNG and GTL feedstock is less than 0.2% by volume. The refrigeration cycles used to liquefy natural gas are very energy intensive and CO_2 emissions from this process are inevitable if power is provided by fossil fuels. Figure A.6.2 shows a schematic of the LNG process, where BOG refers to boil off gas and EFG refers to end flash gas. Both should be captured to avoid fuel waste.

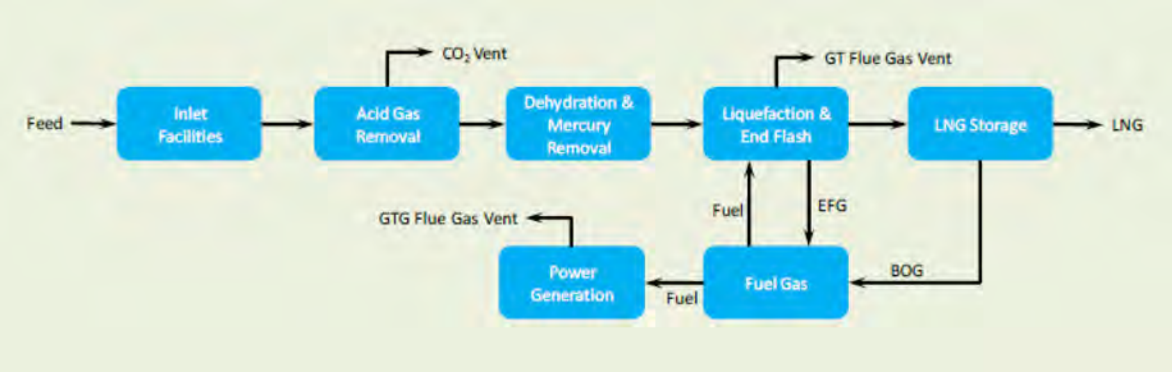

Figure A.6.2. The LNG process

Table A.6.3 shows typical emission factors a liquefaction process (Tamura et al. 2001):

Table A.6.3. CO2 emissions from the liquefaction process of LNG production. Average, numbers will change depending on the sources of natural gas

Liquefaction process	**CO_2 emission, kg CO_2/GJ LNG**
CO2 from fuel combustion	5.24
CO2 from flare combustion	0.33
CO2 in raw gas	1.72

This table shows that, once CO_2 is removed from the raw natural gas, most of the CO_2 emissions from the liquefaction process is from fuel combustion. CO_2 emissions from fuel for LNG liquefaction plants are typically in the range 4.4 to 5.9 kg CO_2/GJ (0.24 to 0.32 tonne CO2/tonne LNG).

It should be noted that CO_2 emissions from the liquefaction process arises from the combustion of natural gas and as a result, the CO_2 concentration in the exhaust gas is low (~3-4%). This makes application of traditional CO_2 removal technologies, such as amine scrubbing, costly to deploy.

CO_2 emissions from flaring have been strongly reduced in many regions. The intermittency of safety flaring does not easily lend itself to CCS.

A.6.3. Non-CCS technologies for reducing and eliminating CO_2 emissions in natural gas production

For compressed natural gas production, the presence of native CO_2 is inevitable and there are little non-CCS solutions available to address this. It is possible to reduce the CO_2 emissions of other operations through electrification if carbon free electricity source is available. CO_2 emissions can also be reduced by improving efficiencies of turbomachinery and process integration.

For LNG operation, with optimisation of the heat and power balance, CO_2 emissions from fuel consumption can be reduced by approximately 30%, leading to CO_2 emissions from fuel in the range of 3.1 to 4.1 kg CO_2/GJ (0.17 to 0.22 tonne CO_2/tonne LNG). Similar to other processes, carbon free electrification is an option.

Another source of CO_2 emissions not directly associated with natural gas production is the transport of the produced natural gas. LNG, especially, is transported by ships or trains using diesel fuel. By replacing diesel operated ships or trains with battery powered ships or trains, the CO2 footprint of natural gas can be further reduced.

A.6.4. CCS technologies for the natural gas industry

CCS for compressed natural gas production

Capturing and storing CO_2 from high-CO_2 content natural gas field presents some of the least costly earliest opportunities for large-scale deployment of integrated CCS projects across a number of world regions. CO_2 in natural gas can be removed using several technologies, such as absorption, pressure swing adsorption and temperature swing adsorption as well as cryogenic CO_2 removal. Solvent absorption, in particular, is a mature technology to separate natural gas from its native CO_2 and is widely used. The captured CO_2 can be stored underground in a geological reservoir. Gas processing facilities typically have access to in-situ or close proximity storage sites of known geological characteristics and there is a considerable skills and knowledge base within the oil and gas industry to undertake large commercial-scale projects. Since CO_2 in the raw gas must be removed before natural gas can be processed, this CO_2 should already exist in a form that is easily amenable to be captured and stored in the depleted natural gas reservoir with acceptable cost. There are a number of significant CCS projects based on the capture of native CO_2 from the raw natural gas. These include Sleipner and Snøhvit (Europe), Terrel natural gas processing plant, Shute Creek gas processing facility, and Century Plant (USA), In Salah (Algeria), Petrobras Santos Basin (Brazil), Uthmaniyah (Saudi Arabia), Abu Dhabi (United Arab Emirates), and soon Gorgon (Australia) and several others. In the cases for Sleipner, Snøhvit and Gorgon, without the capture and storage these fields would have emitted an additional 0.9, 0.7 and 3.6 Mt/year CO_2 on average, respectively. The Sleipner-T plant produces about 1 Mt/year of pure CO_2, which is injected into a deep saline aquifer below the North Sea. For the Snøhvit project, more than 4 Mt of CO_2 has been stored to date since 2008 off shore Norway (Global CCS Institute 2018). For the Gorgon project, it is estimated that 100 Mt of CO_2 will be captured and sequestered over the lifetime of the project, reducing its GHG emissions by 40%. For these gas fields, the CO_2 must be removed to meet sales specification. With CCS, some additional costs arise from the compression, transport and injection of CO_2 into a geologic formation.

CCS for LNG production

Figure A.6.3 shows an example of how CCS could be implemented in an LNG plant. A post-combustion capture unit is placed after the power generation unit and the captured CO_2 is directed to a drying and compression facility for transport. The CO_2 from the acid gas removal unit is also directed to the drying and compression facility rather than being vented.

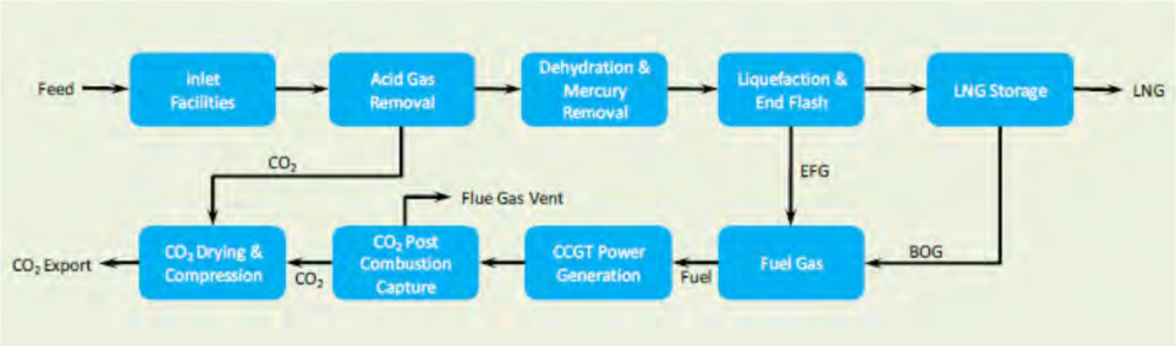

Figure A.6.3. LNG plant with CCS

Table A.6.3 indicates the possibilities for CO_2 reduction by CCS for natural gas and LNG production, with the most promising CCS technologies, their reduction potential, and status.

Table A.6.4.. CO_2 abatement potential by CCS for natural gas and LNG production processes

Facility/ Process	Most promising capture technology	Potential for CO_2 reduction by CCS, %	Challenges	Status of development/expected deployment	Source
Removal of CO_2 from raw gas	Post-combustion with amine	Depending on sales spec		Already implemented	Sleipner, Snøhvit, Gorgon, etc.
Power, compression	Post-combustion with amine	80-90	High costs, lack of commercial and political incentives	Implemented on some power plants	Boundary Dam, Petra Nova
CO_2 from flare			Not practical for safety flaring		

A.6.5. Cost and Challenges

The challenges for CCS from natural gas production are similar to other sectors, notably increased costs. For compressed natural gas production, since CO_2 must be removed from the raw gas to meet the requirements for transportation and sale, the additional costs associated with compression and injection of the captured CO_2 are considered as acceptable since there is no need for long-distance transportation of the captured CO_2 and some of the production facilities can be used for the purpose of CCS. For example, the $100 million CCS operation was just 2.5% of the overall $4 billion cost of the In Salah gas production complex. That puts the cost of sequestering the CO_2 at about $14/ton (MIT Technology Review, https://www.technologyreview.com/s/411417/algerian-carbon-capture-success/).

For new CO_2 rich gas reserves, it will be essential to capture and store or use CO_2 because one of the main reasons for natural gas development is its lower GHG emissions and so it is important to avoid as much CO_2 as possible during its production.

For LNG production, the CO_2 concentration in the exhaust gas is low (~3-4%), which makes application of traditional CO_2 removal technologies, such as amine scrubbing, costly to deploy. It is estimated that a 10% efficiency penalty is incurred with the post-combustion CO_2 capture technology for LNG production, which is similar to the power sector. One study estimated that the CO_2 avoided costs vary from US$60-180/tonne CO_2 (Coulson et al. 2010). R&D efforts have focused on reducing the power requirement for CCS systems as well as on improving energy efficiencies of current LNG production process. It is important to note that the CCS technologies for LNG plants are similar to those for other sectors, notably power generation.

Compared to the CO_2 emissions from the end use point of natural gas, those from LNG production are minor, accounting for only 10% of the total. It has been suggested that effort should be concentrated to curb CO_2 emissions from the end use point of the natural gas because it is more cost effective.

A.6.6. Conclusion

Of the technology options considered for reduction of CO_2 emissions from the production of LNG, including upstream processes, CCS is the only one that can give significant results in the required time frame. Technology exists and has been implemented in the upstream gas production and the power sectors.

A.7 Heavy Oil Production

A.7.1. Present and future CO_2 emissions from heavy oil production

There are two ways of tapping the oil from oil sands: mining and subsequent processing and in-situ drainage of the oil in place. Compared to the production of conventional oil, productions of heavy oil present additional environmental concerns, including increased GHG emissions. These concerns arise from the need to heat the heavy oil by steam injection to pump it out of the ground in the in-situ extraction process and the need for hot water or steam at various stages in the mining approach. Both approaches need upgrading of the heavy oil by hydrogen. Figures 4 and 5 show the flowchart for the in-situ bitumen extraction (Oil and Gas Magazine) and bitumen extraction process (McDougall 2006) approaches, respectively. The more energy intensive extraction processes and the upgrading associated with oil sands exploration and production cause increased CO_2 emissions, and has led to deep concerns on the impacts on climate change.

In Venezuela, due to the lower viscosity, more conventional technologies, such as primary production, can be used to extract the heavy oil, albeit with a lower recovery factor. The CO_2 intensity from Venezuela's heavy oil field is similar to, or slightly higher than, that of Canada's oil sands production Masnadi et al. 2018).

Currently, 55% of bitumen in Canada are extracted using the in-situ approach. It has the advantage of smaller footprint than surface mining, requiring less water and not producing a tailing stream. In-situ process produces ~65-80 kg CO_{2e}/bbl. This method will become increasingly important as it represents 80% of Canada's oil sand resources. Note that GHG emissions are commonly reported as CO_2 equivalent in the oil industry, which takes into account not only emissions of CO_2 and other GHGs, such as methane, nitrous oxide, etc., but also their corresponding global warming potentials. However, it is reasonable to assume that CO_2 is the dominant GHG. Figure A.7.1 shows a schematic of the iun-situ bitumen extraction process.

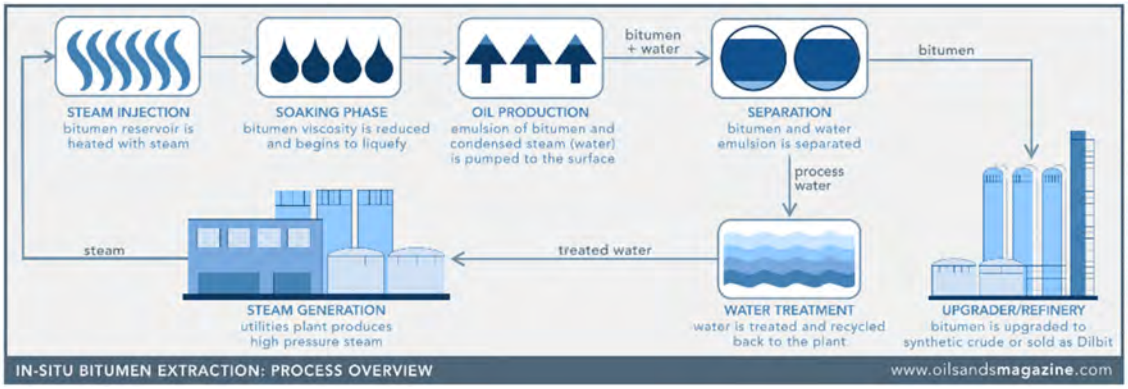

Figure A.7.1. In-situ bitumen extraction process

Surface mining, which accounts for 45% of Canada's current production and 19% of oil sands reserves, offers the advantages of higher recovery rates and lower GHG emissions. Typical bitumen extraction process produces ~40 kg CO_2e/bbl (McDougall 2006). It consists of a surface mine, a bitumen production circuit to separate the solids and water, a tailings pond to store solids and recover process water, a tank farm to hold the required inventories of product and diluent, and a utilities plant to supply steam, power and water to the facility. A schematic of the bitumen mining process is shown in Figure A.7.2.

Once the mined oil sands is transported to the processing plant, bitumen is separated from solids and water within the bitumen production facility in three basic steps:

- Ore preparation: Hot/warm water is added to the oil sands producing a slurry that can be pumped to the processing plant
- Bitumen extraction: Bitumen is gravity separated from the coarse solids producing an intermediate bitumen froth product
- Froth treatment: Solvent or diluent is added to the bitumen froth, reducing the bitumen viscosity and allowing for removal of remaining water and fine solids. Froth treatment produces a relatively clean bitumen product, containing at least 98% bitumen with residual amounts of water and fine solids.

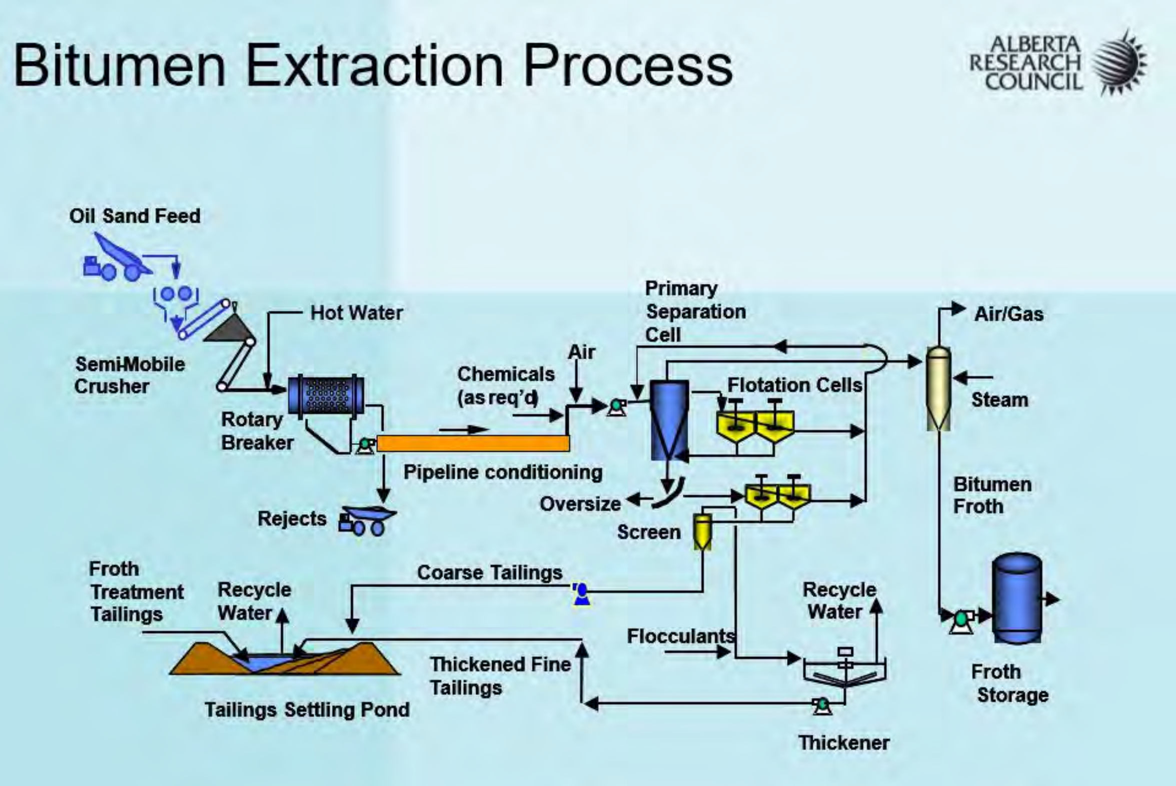

Figure A.7.2. Bitumen mining process

It is important to stress that it is the reservoir characteristics that dictate the appropriate bitumen extraction technique. Reservoirs that are too close to the surface cannot be recovered in-situ since the risk of steam blow-out would be too high. Deposits that are too deep cannot be economically mined. The ideal in-situ reservoir sits at least 200 meters below the surface, while mining operations are typically less than 70 meters below. Deposits that are in the middle (too deep to be mined but too shallow to be recovered in-situ) lie in an area where neither process will work (Oil and gas magazine).

A.7.2. What are the sources of CO_2 emissions from heavy oil production

One of the sources of CO_2 is the requirement of Canadian oil sands operations for thermal energy. These are steam, hot water and heating fuel requirements for different processes and facilities. Natural gas is the main fuel used for this purpose. Upgraders' fuel gas and synthetic gas, as well as in-situ associated gas and in some instances, solid petroleum coke is also used as fuels for thermal energy production.

Steam is used at in-situ thermal operations in order to move the bitumen from the reservoir to the wellhead. Steam is also used in the separation process at mining and extraction operations. At upgrading projects, steam is used and generated across various process units.

Hot water is used in mining and extraction projects at the different extraction and separation stages and it accounts for the majority of the thermal energy used in mining and extraction projects.

Another source of CO_2 comes from hydrogen production. Hydrogen is needed for bitumen upgrading which produces clean sweet synthetic crude oil. Hydrogen is mainly produced with natural gas through the SMR process, though some upgraders use other fuels to produce hydrogen.

Electricity required to operate pumps, compressors, mixers, heaters and injectors at the well pads and at central processing facilities is another source of CO_2. Electricity for oil sands operations can be produced at on-site cogenerations facilities, which produce both electricity and thermal energy, or can be purchased directly from the grid. Canadian Energy Research Institute (CERI) estimates that, as of 2015, there were 15 cogeneration plants serving oil sands projects with a capacity of 2,440 MW (Murillo 2015).

A further source of CO_2 is the diesel fuel mainly used to power trucks and shovels at the mine sites in mining and extraction operations. Some integrated mining and upgrading operations produce diesel on-site at their upgraders in order to meet their project's needs. Diesel fuel may also be used at non-thermal in situ operations for powering pumps and compressors. These factors are the main reasons that GHG emissions are higher for Canadian oil sands operations than for conventional crude oil productions.

Figure A.7.3 shows the GHG sources from various Canadian oil sands operations over the past decade and into 2050 on a business as usual scenario (Murillo 2015). Here, CSS stands for cyclic steam stimulation, SAGD stands for steam assisted gravity drainage, both are in-situ extraction processes requiring large amount of steam. Primary and EOR refer, respectively, to primary oil production for the more fluid areas of the oil sands and enhanced oil recovery, which could rely on thermal injection or steam flooding. However, these two processes are not major pathways for oil sands extraction in Canada.

Figure A.7.3 also shows that, in the business as usual case, the CO_2 emissions will continue to increase and reach a peak of 130 MTPA CO_2e in 2031 before it slowly declines to 120 MTPA CO_2e by 2050.
It can be seen from Figure A.7.3 that production of steam (SAGD+CSS) is expected to have the greatest impact on emissions intensity of any of the individual processes used to produce oil-sands products. Mining (hot water requirement) and upgrading (H_2 requirement) are also significant GHG contributors. Table A.7.1 shows the energy requirement and GHG emissions from various operational steps of bitumen extraction (Murillo 2015).

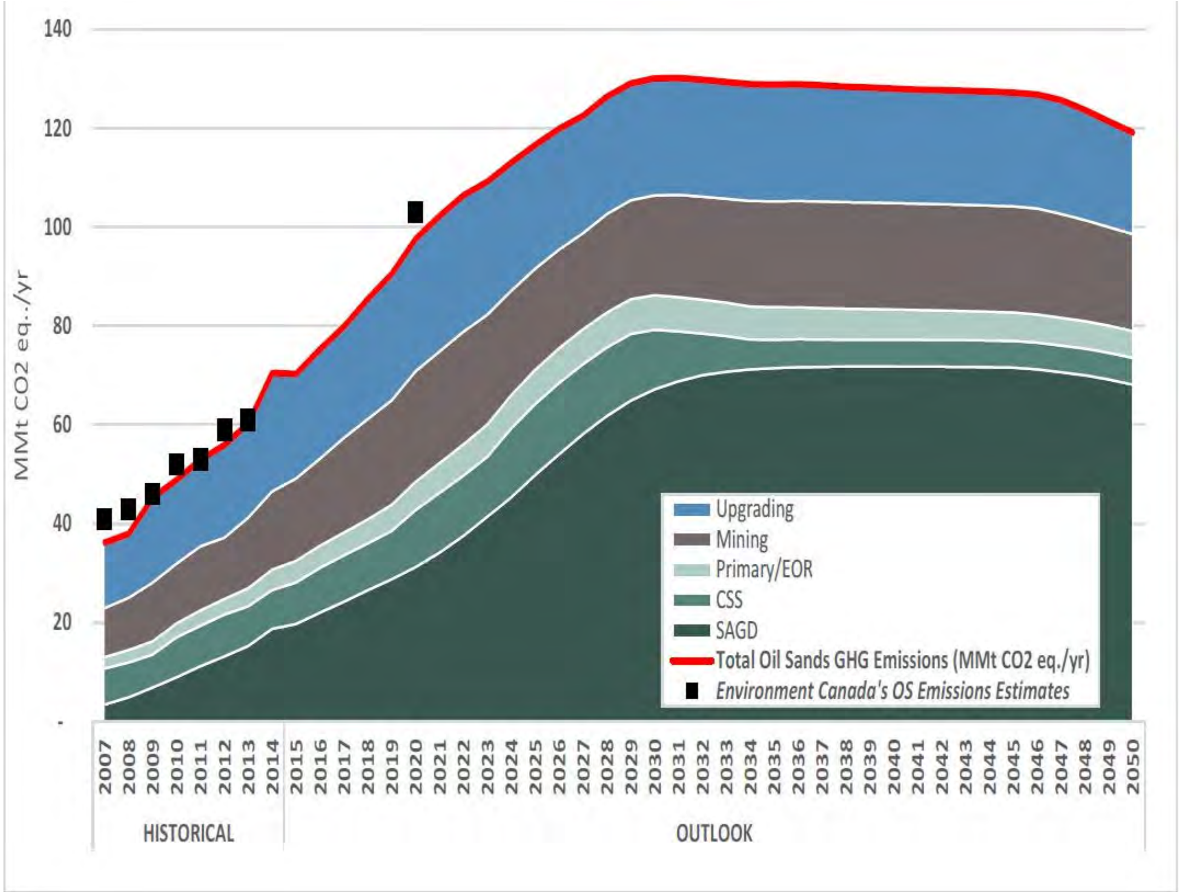

Figure A.7.3. GHG emissions estimates associated with Canadian oil sands end-use energy demand

Table A.7.1. GHG emissions from bitumen extraction

	Energy use, GHG emissions and intensity factors		
	GJ (energy used)/bbl	**kg CO_2e/bbl**	**kg CO_2e/GJ (energy used)**
Oil sands supply	1.3	80.8	62.2
Mining (BIT)	0.5	38.2	76.4
In-situ (BIT)	1.1	69.7	63.4
SAGD	1.2	72.1	60.1
CSS (cyclic steam stimulation)	1.8	107.4	59.7
Primary/EOR	0.6	37.9	63.2
Upgrading (SCO)	0.9	60.8	67.6

Another study (Ordorica-Garcia et al. 2008) presented main energy demand for the Canadian oil sands operations, Table A.7.2:

Table A.7.2. Energy demand for the main Canadian oil sands' operations

Operation	Diesel, l/bbl	Hot water, tonne/bbl	Steam, tonne/bbl	Power, kWh/bbl	Process fuel, MJ/bbl	Hydrogen, m^3/bbl
Mining	1.71	1.08	0.01	16.4		
SAGD			0.39	3.1		
Upgrading			0.10	6.3	59	56.63

It is estimated that the fastest growing source of GHG emissions between 2014 and 2050 will be from the use of thermal energy due to the increased in-situ extraction. GHG emissions from the use of electricity will also increase as the result of higher demand levels but with a lower GHG emissions factor over the outlook timeframe. Emissions from diesel consumption are expected to increase as well by 2050, while emissions from hydrogen production are expected to decline as overall upgrading levels experience a net decline between 2014 and 2050. GHG emissions from thermal energy use by the oil sands industry will remain the single largest source of emissions over the outlook period, with its share of total oil sands GHG emissions increasing from just above 70 percent in 2014 to just below 80 percent by 2050.

The GHG intensity of oil sands production has declined over time. From 1990-2012, the GHG intensity of mining and upgrading operations has fallen by 37% on a well-to-tank basis. Since the inception of SAGD about a decade ago, well-to-tank emissions have declined by 8% (IHS Canadian Oil Sands Dialogue, 2012). According to IHS Markit, the emissions intensity of upstream Canadian oil sands production will continue to decline in coming years, falling to 30 percent below 2009 levels by 2030 (IHS Markit 2018). In fact, according to Suncor, the emissions intensity in 2018 improved by approximately 5.5 percent from the 2014-2016 average intensity. This is due to improved facility reliability and sustained low steam to oil ratios, resulting from optimized reservoir management strategies and strong infill well performance. Despite reductions in the energy intensity of each barrel of oil produced, the absolute level of GHG emissions has grown as oil sands production volumes have increased. However, net increases in GHG emissions from mining projects are expected to moderate. GHG emissions from upgrading are estimated to decrease over the outlook period given overall synthetic crude oil production declines and an increased share of natural gas used for meeting thermal energy requirements (McDougall 2006).

A.7.3. Non CCS technologies to reduce CO_2 emissions

GHG emissions can be reduced with more efficient operations. Process optimization and implementation of best practices at existing projects can lead to increased energy efficiency. New projects should implement best practices and make further advances in avoiding energy waste. An example of ongoing efficiency improvements is the penetration of the new hybrid steam-solvent technologies that partially substitute solvents for steam to reduce steam use—and thus energy and GHG intensity—of in-situ production by 5% to 20% (well-to-tank basis).

Nuclear reactors can be used to meet thermal energy requirement. Toshiba Corporation has developed a small nuclear reactor to power oil sands extraction in Alberta that could be operational by 2020. The reactor capacity would be between 1% and 5% of a typical nuclear power plant, and would not need refueling for 30 years. It would be used to heat water in order to create the steam used to extract bitumen from the oil sands.

Electrical extraction methods can be used for bitumen extraction. In terms of carbon management of oil sands extraction, electrical extraction methods can potentially be attractive as a number of commercially ready electricity generation technologies with low or zero carbon emission exist. A pilot project based on electric heating for bitumen extraction is in operation in Alberta. This option obviously requires carbon-free electricity generation, which can be met with renewable energy sources, such as wind and solar.

Non-CCS alternatives also exist for hydrogen production. For example, biomass gasification can be used for hydrogen production (Oyedun 2016).

Another non-CCS approach is the adoption of electric drive trucks that will remove CO_2 from the operations of diesel-powered trucks.

A.7.4. CCS technologies in heavy oil production

Thermal energy requirement and H_2 production for bitumen upgrading are two of the most GHG intensive processes in heavy oil production. Fortunately, these two processes are also the most amenable to adopt CCS technologies. The forecasted increase in in-situ extraction of the Canadian oil sands also means increased opportunity for CCS because CO_2 emissions from steam generation and H_2 production for upgrading can be captured using technologies already developed for other energy sectors. For CCS technologies associated with H_2 production, please refer to the chapter on H_2 production in this report.

Oil sands operators have been testing CCS technologies in Alberta, notably for hydrogen production, since CO_2 capture technologies for hydrogen production are mature enough to be implemented. Shell's Quest CCS project has been successfully capturing and storing up to 1.2 Mt/year CO_2 from its hydrogen production units (Shell Canada Limited) and Enhance Energy Inc.'s Alberta Carbon Trunkline will transport and store 1.6-1.8 Mt/year CO_2 for EOR purposes (Enhance Energy Inc. Undated). In this case, CO_2 will be captured within the gasification hydrogen supply unit, which will use unconverted asphaltene as feedstock to create syngas with the rectisol acid gas removal technology. In western Canada underground coal gasification for hydrogen production with CCS has also been studied as a viable pathway (Olateji 2013).

While thermal energy requirement is by far the most GHG intensive step in heavy oil production, CO_2 capture from this step can be costly to implement. Technologies such as chemical looping combustion are currently being developed to address this challenge.

A.7.5. Costs and challenges

Similar to other energy sectors, CCS technologies will be costly to implement. In addition, CCS technologies are not easy to implement for oil sands industry because CO_2 streams are relatively small and diluted. Oil sands facilities are also scattered over a vast area and would require additional infrastructure and operating costs to implement CCS technologies.

A particular challenge to CCS in oil sands operations is the low concentration of CO_2 in the process gases. Process streams with CO_2 < 10% are by far the largest source of CO_2, followed by 15%-20% streams and 10%-15% sources. The low-purity CO_2 (0%-10%) is primarily attributed to the SAGD operations, while the medium (15%-20%) and high-purity CO_2 (30%-50%) sources are due to the upgrading operations. Table A.7.3 shows the capture cost estimates for oil sands flue gas streams according to CO_2 concentration (Ordorica-Garcia et al. 2008).

Table A.7.3. Capture cost estimates for oil sands flue gas streams according to CO_2 concentration

2008 Canadian dollars \$/tonne CO_2	**3.5% CO_2**	**9.2% CO_2**	**13% CO_2**	**18.6% CO_2**	**44% CO_2**	**99%+ CO_2**
capital cost (\$MM)	1234	629	479.8	396.8	263.3	117
Capital charges	71.2	36.3	28.8	22.9	15.2	6.2
Fixed costs	43.8	20.5	16.4	13.1	8.6	1.75

Variable costs						
-electricity	23.2	10.5	8.5	6.6	4.5	8.5
-natural gas	26.5	28.4	30.2	28.8	30.5	0.2
-others	6.9	5.9	6.0	4.6	4.4	1.15
Total	171.6	101.6	89.8	76.0	63.2	18.8

t is important to note that the cost estimates in Table A.7.3 only represent the capture cost, not including costs associated with transportation and storage.

The heavy oil industry faces intense competition from conventional oil as well as non-conventional oil productions, especially shale oil in the US. It is further disadvantaged by its relatively high GHG emissions in a carbon constrained world. As a result, the heavy oil industry has a strong motivation to reduce its GHG emissions. In Canada, oil sands operators are exploring various ways to reduce their GHG footprints, as outlined above. This motivation received a new impetus as a carbon tax in Canada has been in place since January 2019. The carbon tax will increase from \$20/t CO_2 in 2019 to \$50/t CO_2 in 2022. This measure is expected to encourage carbon emitting industries, including heavy oil producers, to take measures to reduce their GHG emissions.

A.7.6. Conclusion

Heavy oil reserves have exceeded conventional oil reserve and oil production from heavy oil reserves is expected to increase in the next few decades. Since CO_2 emissions from heavy oil production are generally higher than those from conventional oil production, increased heavy oil extraction will lead to higher CO_2 emissions on a business as usual case. Heavy oil industries are aware of this challenge and are investing in technologies to reduce their GHG emissions.

A.8. The fertilizer industry

A.8.1. Present and future greenhouse gas (GHG) emissions from ammonia production

World agriculture contributes to about 25% of the global GHG emissions, however fertilizer production only accounts for a small fraction of the total emissions. Greenhouse gas emissions nitrogen fertilizer manufacture are associated with two processes, which are the ammonia and the nitric acid processes. Nitrous oxide has long been considered the most important in terms of climate gas emissions from agriculture, first of all because of the direct and indirect emissions from the application of fertilizer, but also in fertilizer production. Effective measures have reduced nitrous oxide emissions from production significantly, which means that today, carbon dioxide from ammonia contributes with higher emissions globally than nitrous oxide from production.

Nitrous oxide from nitric acid production

Nitric acid is produced by burning ammonia over a catalyst at high temperature. Nitrous oxide (N_2O) is generated in an inevitable side reaction in the process. Nitrous oxide is a climate gas 298 times more harmful than CO_2 (US Environmental Protection Agency, EPA, 2016). Total emissions of nitrous oxide from industrial processes contribute approximately 0.2% of global climate gas emissions (roughly 100 Mt CO_{2e}/yr) (IPCC (2006). Most of these emissions are generated in nitric acid production. About 75-80% of global nitric acid production goes to fertilizer (Nitric Acid Climate Action Group, 2017), which means nitrous oxide from fertilizer production accounts for approximately 75 Mt CO_{2e}/yr. Thanks to effective abatement technology, that can be applied at a relatively moderate cost (0.9-3.2 €/ton CO_2 eq), significant reductions can and has been achieved. Yara developed and commercialized an effective catalytic method to remove nitrous oxide that was launched in the market at the turn of the millennium, and has since then reduced own nitrous oxide emissions by more than 95%, and 20-25 Mt CO_{2e}/yr globally.

Present and future CO_2 emissions from ammonia production

In total, present CO_2 emissions from ammonia production are 380 - 420 Mt CO_2 per year, which corresponds to about 1% of global climate gas emissions, and may, with the same technology, fuel, and feedstock mix, increase to above 550 Mt CO_2 per year by 2050.

Note that emissions from fertilizer production include a significant part of the emissions from hydrogen production (for ammonia), and addition of these emissions is not valid.

A.8.2. What are the sources of CO_2 emissions from fertilizer production?

Ammonia is almost exclusively produced from hydrocarbon feedstock, which is needed to produce syngas, from which hydrogen gas, the basic intermediate product in the ammonia process, is recovered by separating it from CO_2. The hydrocarbon, which can be natural gas, coal, naphtha and other, is converted to hydrogen, which in a subsequent step is combined with nitrogen from air in the Haber-Bosch process, where ammonia is generated in a synthesis-loop ("Synloop") at high pressure (100-250 Barg) and moderately high temperature (4-500°C) (Philibert, 2017b). All hydrocarbon-to-hydrogen processes generate CO_2 emissions. The dominating hydrogen process is SMR of natural gas.

The second next common process is coal gasification. This is, however, the dominating technology only in China, and highly unusual elsewhere. Other feedstock, such as heavy fuel oil and naphtha, is also used to a minor and decreasing degree. Coal and heavy hydrocarbons are converted in partial oxidation/gasification processes. As feed to ammonia, approximately 65% of all hydrogen is produced by SMR, 30% by coal (China), 4% by "other feedstock", and 1% by coal outside China (IFA, 2014). Emissions from SMR range from 1.6 – 2.2 t CO_2/t NH_3, to more than 3.8 t CO_2/t NH_3 from coal (IFA, 2017).

In the typical SMR and Haber-Bosch route to ammonia, natural gas is used both as feedstock and fuel in the reformer. The primary reformer, where natural gas is converted to hydrogen and carbon monoxide, is operated at approximately 1000°C, which requires significant heat input. Carbon dioxide is consequently emitted in the flue gas from the reformer furnace. The CO_2 concentration in the reformer flue gas varies, but is typically somewhat higher than in flue gas from a gas fired power plant, and can reach up to approximately 10% (Yara, 2016). The CO_2 emitted with the reformer flue gas typically makes up about 30% of the total emissions from an SMR based ammonia plant. Air is normally added in a secondary reformer stage, in which nitrogen for the ammonia synthesis is introduced, at the same time as residual hydrocarbon is consumed. The process gas exiting the reformer stage, contains hydrogen, nitrogen, carbon monoxide and carbon dioxide. Carbon oxides are acting as catalyst poison in the Haber-Bosch process. All carbon monoxide is therefore converted to carbon dioxide in a *shift conversion* step, and a CO_2 removal stage, normally operated at a pressure of 25 – 35 barg, is a very important element in the ammonia process. Carbon dioxide capture from the process gas is an integrated part of the process, and is needed in all ammonia plants where a steam reformer, gasification or partial oxidation stage is included. A variety of commercially available technologies exist that can be considered best available technologies (BAT) for ammonia production. Most of them are based on ether chemical or physical sorption in a solvent. Examples are:

- a-MDEA: Methyl Di-Ethanol Amine with activators. (BASF)
- Giammarco-Vetrocoke. Hot Potassium carbonate solution with additives
- Benfield: Hot potassium carbonate
- MEA
- PC: Polycarbonate solution
- Rectisol: Methanol based solution (Linde/Air Liquide).

There are also several other CO_2 capture solutions applicable for flue gas that are either at at lower technology readiness levels or not considered BAT for ammonia production, (e.g. chilled ammonia and activated ammonia). These could also be used for process gas, especially if the development in the end delivers solutions that are lower in cost).

About 70% of the total emissions in an SMR based ammonia plant is generated in the process gas. The CO_2 recovered from the common removal processes used with SMR is of high purity (> 90%), with impurities mainly consisting of moisture and non-condensable gases, such as nitrogen. Many ammonia plants form an integrated part of a urea plant, where the pure CO_2 from process gas is recombined with ammonia in a urea synthesis step. Urea is a solid fertilizer product with high nitrogen concentration and it is the largest nitrogen fertilizer product globally by volume. Furthermore, urea has seen a growing use in industrial applications, first of all as de-NO_x reagent in transport and vehicle Selective Catalytic Reduction, SCR, de-NO_x systems. Alternatively, the CO_2 from the process gas is quite easily purified further to >99% purity, which is why SMR hydrogen plants/ammonia plants are preferred CO_2 sources for food grade liquid carbon dioxide. A generic and simplified process diagram is shown in Figure A.8.1 and characteristics of the exit gases are shown in Table A.8.1.

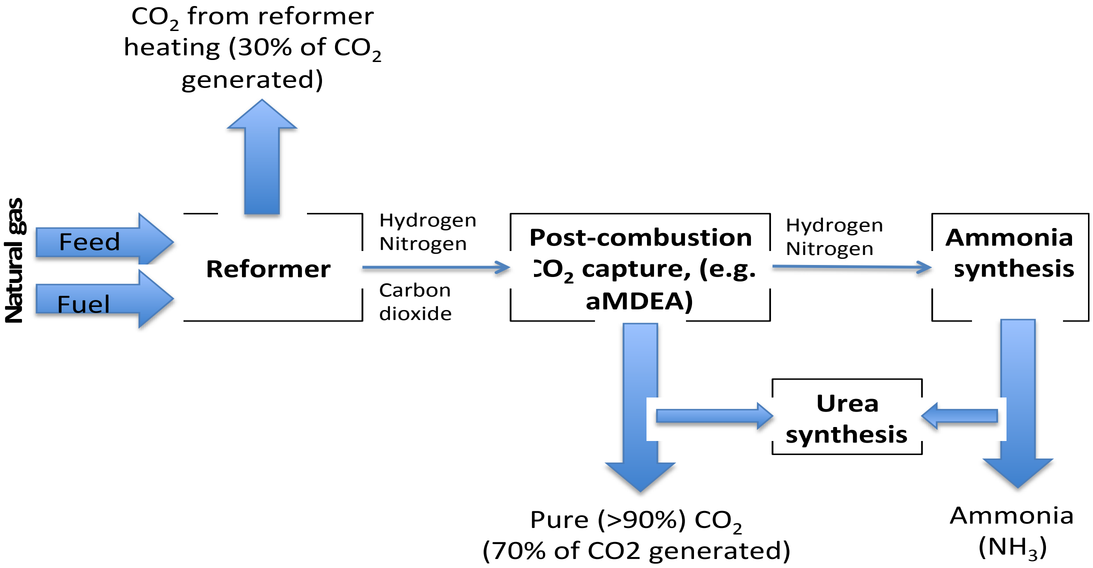

Figure A.8.1: Steam Methane Reformer + Haber-Bosch ammonia, simplified process diagram

Table A.8.1. Characteristics of CO_2 emissions from the different facilities in a fertlizer plant

Facility	**CO_2 emissions, tCO2/t ammonia**	**CO_2 concentration, %**	**Pressure of gas stream**	**Other parameters**
Reformer flue gas	30% of total	Up to 10	Atmospheric	
Reformer process gas	70% of total	>90	25-35 barg	Moisture, non-condensable gases (e.g. nitrogen)
Total	1.6 – 2.2			

The re-use and application of CO_2 from the process gas might be regarded as carbon capture and utilization (CCU), but because the CO_2 in urea is released immediately when applied either as fertilizer or de-NO_x reductant, as well as in typical food applications, as carbonated beverages, the volumes cannot be counted as “not emitted”. In Europe, all CO_2 from ammonia plants are emissions under the ETS scheme, independently of further processing

A.8.3. Non-CCS technologies for reducing and eliminating CO_2 emissions in ammonia

There are two principle ways of reducing, or even eliminating, carbon dioxide emissions from ammonia production. One route is to capture the CO_2 emitted from the flue gas, as well as handling the already captured CO_2 from the process gas, and then exporting the gas for carbon capture for utilization/storage (CCU/CCS) purposes. Further description of status in this field is provided in the next chapter. Continuous focus on increased energy efficiency, and lowering the use of fossil fuel, also reduces the overall CO_2 emissions. The second principal route to emission free ammonia reduction is to avoid carbon all together in feedstock and reformer fuel.

Carbon free ammonia by water electrolysis and Haber-Bosch synthesis

Ammonia, with chemical formula NH_3, is a totally carbon free product. In other words, all carbon found in the feedstock today, is released, and of no direct use. The core technology in ammonia production, is the “everlasting” Haber-Bosch (H-B) process, developed in Germany early twentieth century. The first commercial plant was in operation in 1913 (Philip and Morris, 2001). This process requires pure hydrogen and pure nitrogen into the catalytic synthesis reactor. The process is exothermic, and most energy consumption associated with the H-B process is related to synthesis-loop compressor operation. This means that a virtually carbon free production can take place if hydrogen and nitrogen is produced carbon free.

Hydrogen for various industrial purposes has for years been produced from water electrolysis. Historically, large-scale ammonia production from electrolysis and H-B is proven. In Norway, the default ammonia process in Norsk Hydro, was carbon free ammonia. Hydrogen was produced by water electrolysis (water splitting into hydrogen and oxygen). Electrolysis is energy intensive, and the electricity supply came from hydropower, which is also carbon free. Norsk Hydro produced ammonia via water electrolysis until 1991, when the ammonia plant in Glomfjord was closed (Figure A.8.2). As the cost of electrical power increased, at the same time as the price of natural gas dropped, gas reforming took over and provided the best economy in ammonia production.

Figure A.8.2:.Electrolyser production hall, Norsk Hydro Glomfjord, producing 30 000 Nm^3/hr (NEL Hydrogen)

Producing hydrogen from electrolysis requires in the range of 10-12 MWh/t ammonia (state-of-the-art alkali electrolysers) (a, 2017), compared to approximately 8 – 10 MWh/t ammonia in natural gas based processes. In a CO_2 emission/ life cycle perspective, electrolysis only makes sense if the electricity used for electrolysis comes from renewable power. If the power generated to produce by electrolysis would be taken from conventional hydrocarbon power plants, the total energy efficiency loss would make total energy consumption reach more than 80 MWh/t of ammonia (Banares-Alcantara et al., 2015).

Operating costs, and partly also investment cost, are the main reasons for why water electrolysis is not used in large scale ammonia production today. For smaller commercial electrolyser installations, the investment cost of water electrolysers has been at about 1000 USD/kW Institue for Sustainable Process Technology (ISPT, 2017). State-of-the-art large-scale electrolyser installations (> 50 MW) have a suggested CAPEX of approximately 500 USD/kW (Simonsen, 2017). A significantly lower CAPEX, of

400 USD/kW and below, is required before CAPEX parity is reached between conventional and electrolyser based ammonia.

Cost and availability of renewable power (together with the natural gas market price) is the most important factor determining break-even between conventional SMR plus H-B, and electrolysis plus H-B. Estimates recently done by the International Energy Agency (IEA) (Philibert, 2017b), indicates that at a high load factor (at or close to the 8000 hours per year design capacity of a normal Haber-Bosch ammonia plant), an average renewable electricity price of 30 USD/MWh will make electrolysis based ammonia competitive. How realistic this estimate is, can be discussed, since 8000 operating hours using only renewable energy is hard to achieve anywhere else than in areas with stable hydro-power. In future energy systems where most of the electricity production comes from renewables, and where large regions (Europe +) has unlimited interconnectivity, a similar opportunity may arise. Estimates based on comparison with current average natural gas prices and low/absent carbon prices, are suggesting that the cost of electricity will need to come down to 20 US$/MWh and below (Yara, 2017), to reach full-cost parity, and these cases do also incorporate the not yet seen lower CAPEX for electrolysers. Currently, electricity prices at this low level are not obtained in the market. The cost of renewables, solar power in particular, is however continuing a downward trend. When plant investment cost comes down, in combination with access to low cost renewable energy, and increasing cost of emitting CO_2, ammonia by electrolysis and Haber-Bosch would be competitive from a purely financial point of view.

There is however another potential barrier to overcome before fully renewable ammonia can be produced cost effectively, and that is the lower capacity utilization factor. Renewable power (wind/solar) is by nature intermittent. Operating an ammonia plant purely from a variable source of power, is challenging. The Haber-Bosch process operates most effectively at steady state at design capacity. The conventional H-B process can tolerate variability to some degree, but variable load will increase cost of production. At the same time, the most mature electrolyser technology, alkaline electrolysers, are also not very flexible, adding to the complexity of the system. New Polymer Electrolyte Membrane (PEM) electrolysers are more expensive, but at are the same time less power intensive, more flexible, and seem to handle power variability better than alkaline electrolysers. Ultimately, an ammonia plant operated only from one or few sources of variable renewable energy, will need some form of energy and/or hydrogen buffering capacity, which will drive investment cost significantly. Optimized variable power to ammonia systems are not yet fully understood nor developed.

Figure A.8.3 illustrates an electrolyser plant.

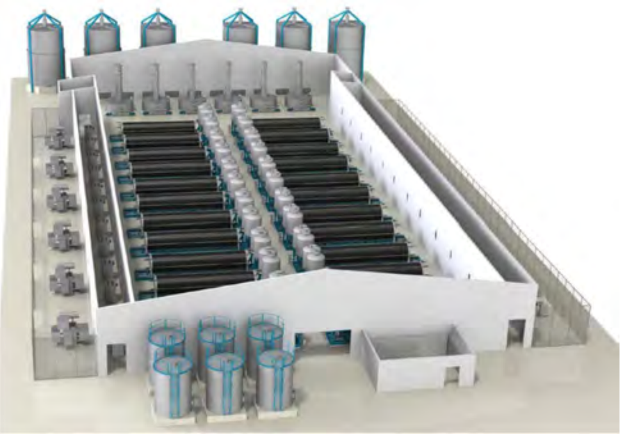

Figure A.8.3. 50 MW electrolyser plant (NEL Hydrogen)

Finally, to make ammonia in the Haber-Bosch process, pure nitrogen is also required. This is easily generated by commercial air separation technology (ASU), as cryogenic distillation or Pressure Swing Absorption (PSA). Power supply evidently needs to be renewable. Some of the same challenges related to variable power supply, is also valid for e.g. cryogenic air separation, which is most effectively operated at steady state.

Emerging technologies

A number of potential technologies have been researched, first of all to reduce the energy required to produce hydrogen, and split nitrogen (US DOE, 2016). Direct electrochemical routes from water and nitrogen to ammonia has been demonstrated in lab scale, but is currently at a low TRL level. The technologies suffer from low yield/high energy consumption, and are currently not solving the main issue of significantly lower energy consumption per unit ammonia produced.

Table A.8.2 summarises the CO_2 reduction potential of some of these technologies, without CCS, and with development/implementation perspectives.

Table A.8.2. Worldwide CO_2 abatement potential for some innovative low-carbon fertilizer processes

Technology	**Potential for CO_2 reduction on a fertilizer plant, %**	**Status of development/expected deployment**	**Source**	**Challenges**
Electrolysis	100 if based on electricity from renewable sources	Electrolysers at TRL 6 - 9, depending on technology Technology ready now Deployment will depend on availability of low cost renewable power and CO_2 emission penalties	Several	Operational, and partly capital, cost; high energy consumption; cost and availability (including intermittency) of renewable electricity
Emerging technologies (electrochemical)	100	Laboratory scale, low TRL		Low yield, high energy consumption

A.8.4. CCS technologies for the Ammonia process

Status

Today, there are two fertilizer plants that collect CO_2 that is used for enhanced oil recovery (EOR);:

- The Koch Nitrogen Company facility in Enid, Oklahoma, USA, collects around 0.7 Mtpa of the CO_2 off-gas and transports it to depleted oil fields in southern Oklahoma for enhanced oil recovery (GCCSI, https://www.globalccsinstitute.com/projects/enid-fertilizer-co2-eor-project
- The Coffeyville Resources Nitrogen Fertilizers fertiliser plant in Coffeyville, Kansas, has been retrofitted with CO_2 compression and dehydration facilities and since 2013 has been delivering CO_2 to the North Burbank Oil Unit in Osage County, Oklahoma, for enhanced oil recovery. Carbon dioxide capture capacity of the compression facilities is around 1 Mt/year (GCCSI, https://www.globalccsinstitute.com/projects/coffeyville-gasification-plant).

A fertilizer plant near Redwater, Alberta, will collect CO_2 from the process and feed it into the Alberta Carbon Trunk Line (ACTL) in Canada (Energy, Alberta). ACTL is under construction, and planned in operation in 2019. The business rationale for this project is Enhanced Oil Recovery (EOR).

In May 2019 Wabash Valley Resources announced the development of a CCS project at an ammonia plant located outside of West Terre Haute, Indiana. The project will receive funding support from OGCI Climate Investments.

- The project is expected to be the largest carbon sequestration project in the United States to date, and will create the world's first ammonia produced with near zero carbon footprint
- The project will capture and sequester 1.5-1.75 million tons of CO2 annually from Wabash Valley Resources co-located ammonia plant
- Ethanol produced from corn using WVR's ammonia will benefit from a significantly lower carbon intensity rating, making US ethanol and corn more valuable in International and California markets.

Technology options

Technologies for CO_2 capture in ammonia production have to be regarded for PROCESS GAS and reformer FLUE GAS. In SMR based ammonia production, about 70% of the CO_2 is generated in the process gas, and 30% in the reformer flue gas (see Section A.8.2).

The reformer flue gas composition resembles somewhat the gas composition from a gas fired power plant, with a slightly higher CO_2 concentration. Amine technologies might be used, and since ammonia is available at an ammonia plant, and the byproduct ammonia nitrate (AN) can easily be handled by a fertilizer company, ammonia technology (General Electric (GE) Alstom) might well be an option; though it needs an activator and process control (for example, to avoid precipitation)

The CO_2 generated in the process gas however, is already captured. The only technology required to make this CO_2 available for export to carbon storage, is a liquefaction and purification plant, and CO_2 storage tanks. The relative cost of this CO_2 handling is only a fraction of what it takes to capture from the flue gas, as the cost of the capturing technology is already an integrated part of the ammonia plant investment. Studies (Yara, 2016/2017) indicate the cost reduction per ton of removing CO_2 from process gas compared to reformer flue gas is in the range of 50%, depending on assumptions. Liquefaction, purification and storage is required independently of origin of the CO_2.

Another option to reduce the CO_2 emissions in the flue gas from the reformer, is to recycle part of the hydrogen produced as fuel to the reformer. Overall, that would shift CO_2 emissions from the reformer flue gas to the syngas, with lower recovery costs. However, this cost saving on CO_2 recovery must be balanced by the increased cost of a slightly larger SMR unit and the cost of hydrogen as fuel compared to natural gas.

Finally, not directly a capture option, but still a solution that holds a significant CO_2 reduction potential, is feedstock conversion, moving away from coal and heavy fuels, to natural gas as feedstock to the reforming process, especially in combination with technologies where almost all CO_2 is generated in the process gas. As an example, Yara converted its existing, POX-based ammonia plant in Germany, which is the largest ammonia plant in Europe, from heavy residual fuel oil to natural gas feedstock. The CO_2 emissions were reduced by nearly 50%, equal to 900.000 tons of CO_2 per year. In addition, the feedstock conversion reduced the emissions of SO_2 and NO_x from the plant by about 50%.

Table A.8.3 summarises the CO_2 reduction potential of some CO_2 capture technologies for the fertilizer industry.

Relevance and attractiveness of CCS in ammonia production

Since CO_2 generated in the process gas is already captured as part of the overall ammonia process, handling these volumes seems to be the shortest and most cost effective way to pursue CO_2 reduction via CCS from conventional ammonia production. Provided a CO_2 storage infrastructure is put in place, close to 65-70% of CO_2 emissions from ammonia could be removed at a relatively low cost compared to e.g. power plant CCS or ammonia flue gas CCS.

Furthermore, in hydrocarbon-to-hydrogen process technologies as POX and ATR[26], more than 90% of the CO_2 is generated in the process gas. ATR or POX could be chosen instead of SMR for natural gas conversion in new plants. SMR is today the dominating hydrogen reforming technology, and considered lowest cost large-scale technology. Improvements in ATR and POX could however make such technology preferred hydrogen reformer technology, and by doing so, enabling a relatively low cost removal of close to 90% of the CO_2 emissions from ammonia, without employing other capture technology than the commercial technology supplied as part of the total ammonia plant. In POX/ gasification of coal, almost all CO_2 is also generated in the process gas.

Table A.8.3. CO_2 abatement potential by CCS for fertilizer production processes

Facility/ Process	**Most promising capture technology**	**Potential for CO_2 reduction by CCS, %**	**Challenges**	**Status of development/expected deployment**	**Source**
Reformer process gas	Already captured as part of overall ammonia process	65-70	General lack of • infrastructure for transport and storage • business and policy incentives	Used for EOR in two plants in USA, i.e. with business incentive	

In a broader industrial carbon reduction perspective, the most (cost) effective CO_2 reduction measure in existing SMR-based ammonia plants would most likely be to handle the 70% fraction of overall emissions that is already captured from process gas, and leave the flue gas untreated. For selected plants, where there are technical and business opportunities for such a solution, the existing SMR might be revamped to reduce both fuel consumption and CO_2 emissions. In new gas based ammonia plants, where there should be an upfront requirement to produce with close to zero CO_2 emissions, and where a carbon storage infrastructure in place, POX/ATR hydrocarbon conversion, with integrated removal of 90-95% of the CO_2, would be the technology of choice.

A.8.5. Costs and challenges

The estimated cost of CO_2 capture from the ammonia process varies significantly. A study of CCS cost from SMR with five different case solutions (Santos et al., 2016), published in 2016, concluded with a "CO_2 avoidance cost" of 47-70 €/ton CO_2. McKinsey estimated in 2009 the CCS cost from ammonia to be 50 US$/t CO_2 McKiney, 2009), while IEA operates with varying figures ranging up to 100 US$/t CO_2 IEAGHG, 2017). The public assessment of the Norwegian CCS Project after feasibility phase, concluded with a total CO_2 cost of approximately 210 US$/t CO2 from Yara Porsgrunn ammonia plant (Atkins, 2016), taking all investments and operating expenses into account over the expected lifetime of the plant. This number includes cost (CAPEX and OPEX) of an oversized CO_2 storage (oversized by intention as the storage is beeing design for more that one capture project). It is very difficult to compare the cost figures, since they are calculated with different assumptions, with different estimation methods, with/without transport and storage cost, and for different locations, meaning that CAPEX and OPEX

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[26] Auto Thermal Reforming (ATR):
As described in Chapter 1, the conversion of natural gas to syngas in the ammonia process, normally takes place in a two-stage reforming process, where the first step is the SMR, and the second step a so-called *secondary reformer*, used to introduce nitrogen from air, and to convert residual hydrocarbon by combustion with oxygen from the air. This secondary reformer is in essence an ATR. The entire process could however be based on ATR/POX, without the SMR.

can vary significantly (IEAGHG, 2018). The cost figures arising from the Norwegian CCS Project, are based on thorough feasibility studies, and might be regarded realistic compared to more conceptual studies.

Carbon capture is, as mentioned in Section A.8.1, practiced for all CO_2 generated in the process gas, but not for storage purposes, except for the mentioned three projects mentioned in Section A.8.4. There are two main reasons for this:

- Lack of CO_2 capture incentives
- Lack of
  a) Commercial opportunities
  b) Feasible business case
  c) Available commercial transport and storage infrastructure

The industry has no incentives today to handle CO_2 differently from current practice. The cost of handling CO_2 cannot be transferred to customers, as ammonia/fertilizer are globally traded products, which means ammonia/fertilizer which is not produced with CO_2 capture, will be available in the market, making the "low CO_2 ammonia" non-competitive. The penalty for emitting CO_2 is there in important ammonia producing regions, such as Europe (ETS), but the cost of emitting CO_2 is still significantly lower than the cost of investing in CO_2 capture. The industry would also argue that unless an increasing penalty for emitting CO_2 is related to mechanisms applied globally, the only result of high local CO_2 prices, would be industry relocation to areas in the world with no or less CO_2 penalties. Moving ammonia capacity from Europe to China, with an increased fraction of ammonia produced from coal gasification, would have the unwanted and opposite effect, with increased global CO_2 emissions.

A.8.6. Conclusions

Any permanent reduction of CO_2 from existing ammonia plants would require CCS, or commercially attractive EOR options, and more specifically, a CO_2 storage infrastructure. On the capture side, both technically and from a cost perspective, the easiest way forward to reduce CO_2 emissions from existing ammonia plants that involve syngas as an intermediate, is preparation (liquefaction and purification) of already captured volumes from the process gas for export. The least attractive approach from a cost perspective, is to build CO_2 capture plants from reformer flue gas.

For new, natural gas-based ammonia capacity, the best preparatory measure seems to be the construction of hydrogen technology where more than 90% of the CO_2 is generated in the process gas, as in ATR or POX. This would most likely reduce both cost and complexity of CO_2 capture from ammonia production, but has to be balanced against the potential expense of an overall plant cost increase.

Ammonia from renewable energy via electrolysis can stand on its own in the sense that the ammonia industry do not depend on other industries to develop infrastructure in order to implement CO_2 reducing technology. Considering the accelerated deployment of renewable power towards 2030, investments in fully decarbonized ammonia production by electrolysis plus Haber-Bosch, might be preferred to new conventional + CCS for the industry.

There are two key issues that would need be to resolved:

1) CCS for the fertiliser industry will only be possible if transport and storage infrastuctures, possibly in connection with EOR solutions, are put in place (by regulators and other industry clusters) to create a feasible business case
2) In renewable power to ammonia, intermittency and connectivity issues, with cost implications, which today are not fully understood, will need to be included in new plant designs and feasibility studies

A.9. The waste-to-energy (WtE) industry

A.9.1. Present and future CO_2 emissions form the waste-to-energy industry

Municipal Solid Wasre (MSW) has a significant energy potential and a high organic content and is suited for energy extraction and utilisation. In addition to the economic benefits, utilisation of the energy stored in the waste, there will be environmental benefits, e.g. if waste as fuel replaces conventional fossil fuels. Diffuse emissions from landfills can be displaced by point sources were CO_2 can be captured, and toxic run-off from un-esthetical landfills may be avoided.

There are two kinds of WtE plants in operation: 1) Incineration plants, and 2) plants that collect and burn gas from landfills (LFG plants). Worldwide there are around 760 MSW incineration plants and 1150 LFG combustion plants in operation (Pour el al., 2018). LFG combustion will, result in GHG emissions that are significantly higher higher than for incineration, Figure A.9.1. However, incineration creates other emissions unless precautions are taken, and is in general more costly than LFG combustion (Pour et al., 2018).

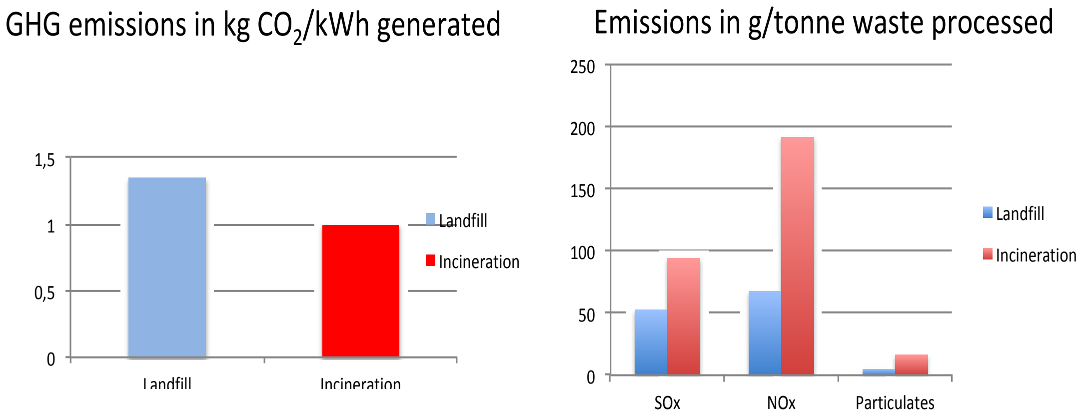

Figure A.9.1. Emissions of incineration and burning of methane from landfill a) GHG emissions (after Pour et al., 2018); b) other emissions (after WEC, 2016).

Today, considering that 200Mt/year of the MSW are converted to energy by incineration and that in a modern incineration plant, emissions are around 1t CO_2/t MSW (gross emission, no credit for biomass content, Pour et al., 2018; Johnke, 2001; however, the mission factor will vary depending on composition of the MSW), the global CO_2 emissions from WtE are around 0.2 Gt CO_2/year. Future CO2 emissions and possibilities for CCS will depend on introduction of WtE plants, which will be decided by national and local policies.

A.9.2. What are the sources of CO_2 emissions from the WtE industry?

There are several technologies available for converting MSW into energy forms (WEC, 2016):

1. Thermochemical conversion. Here there are three options:
    a. Incineration. Here complete oxidation of the combustible materials leads to flue gas, ash and heat. The mass that needs to be removed is reduced by 90%. The heat can be used to produce electricity and/or heat
    b. Gasification, which is the partial oxidation of the waste in the presence of an oxidant. The product is called syngas, consisting mainly of carbon monoxide, hydrogen and carbon dioxide, which can be used for generation of electricity, heat or fuels. For solid waste, the heterogeneous nature and cleaning of the syngas has several challenges and there are few such plants

    c. Pyrolysis, which involves the thermo-chemical decomposition of waste fuel at high temperatures in the absence of air. The waste is converted into syngas, liquid tar and solid char.
2. Bio-chemical conversion with the options:
    a. Anaerobic digestion in which organic material is broken down by micro-organisms in the absence of oxygen, producing a methane-rich gas (bio-gas)
    b. Fermentation, in which organic material is converted into acid or alcohol in the absence of oxygen, and leaving a nutrient-rich residue
    c. Microbial fuel cell (MFC), a biochemical-catalysed system where electricity is produced by oxidizing biodegradable organic material in the presence of bacteria or enzymes.
3. Chemical conversion, involving the reaction of an acid and an alcohol to create ester to form bio-diesel and glycerol for the cosmetic, pharmaceutical, food and painting industries.
4. Utilisation of landfill gas (LFG), where the gas is collected and burnt in internal combustion engine, a gas turbine or a boiler that provide steam to a steam turbine.

WtE opens several applications:
1. Electricity. Released heat during combustion, gasification or pyrolysis of MSW can be used to produce steam for a steam turbine. In the case of gasification and pyrolysis the syngas produced can be further refined and used to drive gas turbines or engines. The same goes for different gases produced from bio-chemical and chemical treatment of MSW.
2. Heat can be generated through the production of steam or by upgrade of the syngas for injection into gas networks and use in domestic boilers or appliances. The same goes for different gases produced from bio-chemical and chemical treatment of MSW.
3. Combined heat and power (CHP), in which heat generated during the electricity production is captured and utilized. The same goes for different gases produced from bio-chemical and chemical treatment of MSW.
4. Transport fuels. Syngas and/or hydrogen produced during gasification and pyrolysis, as well as biodiesel and ethanol produced from bio-chemical and chemical conversion of MSW, can be applied in vehicles as a substitute for fossil fuels, including jet fuel.

Both incineration and LFG utilisation offer good opportunities for CCS. After the LFG has been collected in option 4 above, the CO_2 capture is very similar to regular and heat and/or power production using natural gas. According to Pour et al. (2018), who studied CO_2 capture applied to both technologies, MSW with CCS is a more favourable solution than LFG with CCS from a CO_2 mitigating point of view but also the most costly. *Since MSW is by far the dominating technology it will be the focus of the rest of this chapter. LFG with CCS is not considered further here.*

Figure A.9.2 shows a schematic of a WtE plant based on combustion.

Based on a Norwegian WtE plant (Fortum Oslo Varme at Klemetsrud in Oslo) that has undertaken concept studies for CCS (Bjerkås, 2017) the following information can serve as an example of a modern WtE plant with direct incineration of special waste (2017 numbers):

- Organic content in waste: 60%.
- Capacity: 375 000 t/year, plans to increase.
- Electricity production: 148 GWh.
- Heat sales: 690 GWh (district heating).
- Steam for the steam turbine: 380 ^{o}C.
- Oven temperature. At least 850 ^{o}C.
- Metals in bottom ash are recovered (Recovering metals from the bottom ash could represent savings of 1.5 kg CO_2 /kg iron scrap or 10 kg CO_2/kg aluminium.).
- Fly ash and sludge used for landfill.

- Flue gas cleaned by advanced technology. Activated coal binds contaminants; el-/physical filter removes particles: scrubber removes HCl and SO_2; selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) reduce NO_x.

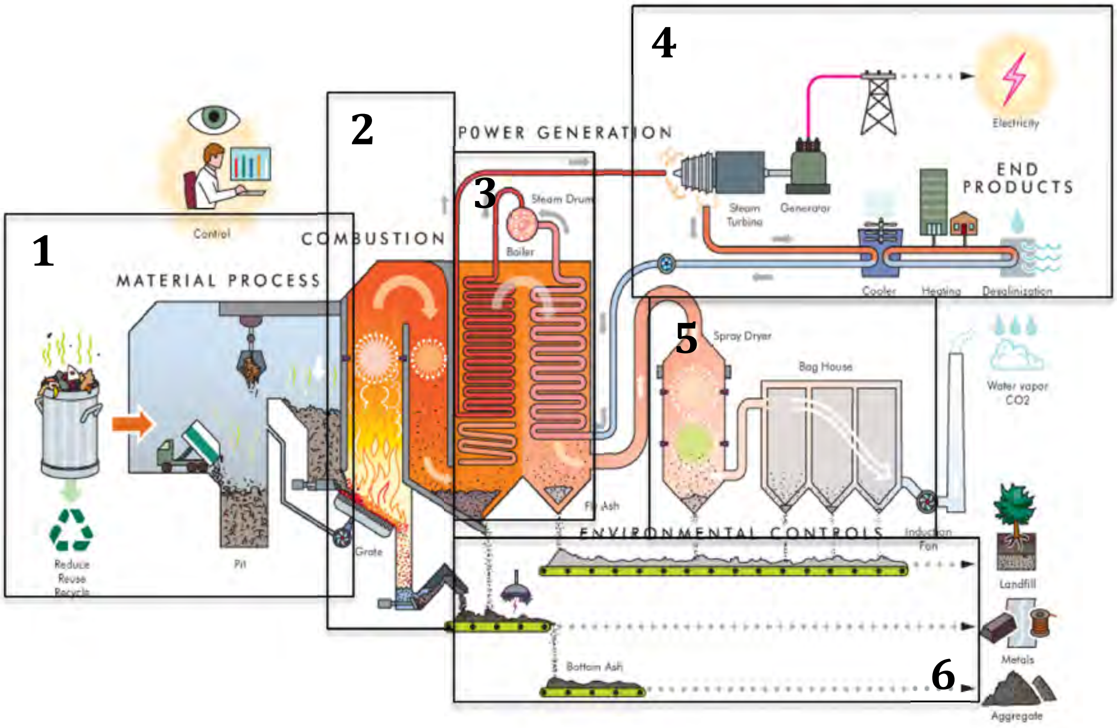

Figure A.9.2 Schematic of an incineration WtE plant (based on EIA, 2018). The process has several stages:

1. **Waste is transferred to the combustion chamber.**
2. **The waste (fuel) is burned, releasing heat.**
3. **The heat turns water into steam in a boiler, cooling the combustion process.**
4. **The high-pressure steam is piped to a turbine generator to produce electricity and district heating.**
5. **An air pollution control system removes pollutants from the combustion gas before it is released through a smoke stack**
6. **Ash is collected from the boiler and the air pollution control system.**

It should be noted that recovering hydrochloric acid and excess lime is rare and not done at Klemetsrud, but could have some contribution to the entire circular green economy.

CO_2 emissions from the Klemetsrud plant are estimated to 400 000 t/year (based on e.g. Johnke, 2001 and and Pour et al, 2018, both of whom give a rough estimate of around 1 t CO_2/t MSW).

The flue gas WtE plants has similarities to the flue gas from coal-fired power plants, as indicated by e.g. Zevenhoven and Kilpinen (2005). They show CO_2 content of 6-12 %-v for MSW and 7-13%-v for coal power generation, depending on technology, and values for all in the range 0.1-1 ppmw for Hg and Cd. Water content is a higher for MSW, 10 – 18 %-v compared to 1-6 %-v for coal. The flue gas exits the stack at atmospheric pressure.

Characteristics of the specific CO_2 emissions from a MSW incineration plant are as shown in as in Table A.9.1.

Table A.9.1. Characteristics of CO_2 emissions from the different facilities in a WtE plant

Facility	CO_2 emissions, tCO2/t waste incinerated MSW*	CO_2 concentration, % **	Pressure of gas stream,	Other parameters **
Combustion	1-1.2	6-12	Atmospheric	Depending on waste composition, may include VOC, PAHs, trace elements, halogens, dioxins, chlorines

* Johnke, 2001 and Wikipeda

** Zevenhoven and Kilpinen (2005)

A.9.3. Non-CCS technologies for reduction of CO_2 emissions form the WtE industry

Residual waste cannot and should not be recycled, therefore, sorting and recycling should not be presented as an alternative to WtE and CCS. Waste reduction and reuse are important measures to keep the resources in circulation and reduce the production of new materials/metals/products, but for residual waste WtE is the best solution. Controlled use of waste for landfill may in some cases be an alternative.

The technologies other than combustion for WtE plants mentioned in Section 3.9.2 also result in GHG emissions, directly or indirectly. If the products (methane, hydrogen, syngas, bio-fuels) are used to replace fossil fuels, they will contribute to reduced CO_2 emissions.

Unfavourable physical properties of the solid fuel, unfavourable composition of the waste fuel, and small units lead to less efficient cycle configurations than in power stations. Improved energy efficiency is unlikely to reduce CO_2 emissions, which are determined by the amount and carbon content of the waste, but it may result in increased revenues as more heat and/or power can be sold.

Thus CCS appears to be the solution to reduce CO2 emissions from a WtE plant.

A.9.4. CCS technologies for reduction of CO_2 emissions from the WtE industry

Toshiba Corporation (2016) has announced that it has completed the world's first commercial- use carbon capture and utilization (CCU) system constructed in a municipal waste incineration plant, in Saga Japan. The plan was divided in two phases. Firstly, Toshiba, Kyushu Electric Power and Ebara Environmental Plant started the operation of a CCU testing facility in 2013, and captured 10 kg CO_2 a day from the flue gas of the incinerator. The WtE plant supplied power and heat for the capture system. The captured CO_2 was used in crop cultivation and algae culture, demonstrating its fast growth and the absence of hazardous substances. The system is based on carbon capture technology by chemical absorption that Toshiba developed for thermal power plants. An alkaline aqueous amine solution introduced into the flue gas released during waste incineration absorbs its CO_2. When this solution is heated, the CO_2 is separated and captured with a high degree of purity. Based on the successful results, the municipal government commissioned Toshiba to build a 10 t CO_2/day capture plant for the WtE facility in 2016. In this case, the captured CO_2 is sold to an entrepreneurial venture for their alga cultivation business and transported via a 200 m pipeline. The final product will be raw materials for cosmetics and nutritional supplement. Excluding the grant and supply of power and heat, the levelized CO_2 supply cost is approximately half of the price of the tonne of CO_2 in the market (IEAGHG, 2016).

Two types of post-combustion capture technologies have been evaluated for CCS at the Klemetsrud plant: Proprietary amines, and chilled ammonia. Both technology types have completed successful test programmes at Technology Centre Mongstad in Norway (TCM) and in other pilot plants. As Klemetsrud delivers heat to a district heating system in Oslo, a heat recovery system including heat pumps and steam turbines will be installed to recover and return sufficient thermal energy for the capture plant without reducing the heat deliveries to the district-heating grid in Oslo, even in winter. Electricity needs for both technologies will met by the internally produced electricity. Efficient energy integration and the use of air coolers have removed the need for establishing a cooling water system or reinforcing the electricity supply for the plant. Reduction potential and status for CO_2 capture technologies from a WtE plant are indicated in Table A.9.2. The captured CO_2 will be piped or trucked to Oslo Harbour for further transportation by ship to a terminal on the west coast of Norway, from where it will be piped to an offshore storage site (together with CO_2 from a cement plant).

In the Netherlands, the WtE company AVR plans to start construction of a MEA capture facility at its WtE plant in Duiven in 2019. This is a power plant with 70 MW capacity that incinerates MSW to produce around 126 GWh electricity. The capture capacity will be up to 50 Ktonnes CO_2 per annum and will operate within a seasonal schedule, alternated with the demand from district heating. The CO_2 will be used for horticulture in greenhouses.

Table A.9.2. CO2 abatement potential by CCS for WtE industry

Facility/ Process	**Most advanced capture technology**	**Potential for CO_2 reduction by CCS (from baseline integrated), %**	**Challenges**	**Status of development/expected deployment**	**Source**
Combustion unit	Post-combustion absorption	> 90 or even negative considering that much of the waste is biogenic	Cost, lack of commercial and political incentives	Pilot (Norway) and demo (Japan). Duiven (Netherlands) is under construction	Bjerkås (2017); Toshiba (2016)

WtE with CCS can obtain negative CO_2 emissions due to the large fraction of organic waste. This could be the next step towards emission free waste handling.

A.9.5. Costs and challenges

Early estimates for the Norwegain first-of-a-kind WtE plant showed cost of 2400 NOK /t CO_2 (280 – 300 US$/t CO_2 depending on exchange rate) (Atkins and OsloEconomics, 2016). This number includes cost (CAPEX and OPEX) of an oversized CO_2 storage (oversized by intention as the storage is being designed for more that one capture project).

In general, WtE does not compete in a larger market and costs are usually transferred to the citizens. The costs must be seen in the wider context of societal benefits in reducing greenhouse gas emissions. They may come down if there are changes in the CO_2 tax regime.

In addition to the added cost for WTE with CO_2 capture, there are challenges connected to lack of infrastructure for transport and storage of the CO_2, as well as lack of business incentives and models for cost and risk sharing.

Considering the added cost to electricity from WtE plants with CCS, Pour et al. (2018) estimated that for a MSW incineration plant, the levelised cost of electricity will increase by around 50% (150 US$/MWh to 225 US$/MWh) and by 150% for LFG combustion (65 US$/MWh to 165 US$/MWh).

A.9.6. Conclusions

CO_2 capture on waste-to-energy plants is the only way to reduce emissions from such plants. The technology exits and has been tested in pilots. Implementing CCS on WtE plants is feasible, but challenges connected to costs, infrastructure and incentives must be overcome. Due to a high organic content in the waste, net negative emissions may be achieved with CCS on WtE plants.

A.10. Extensive summary of current development status and gaps in CCUS technologies for industry

Deployment of carbon capture and utilization seems to be the plausible technology option in short/ medium term perspective to meet future global climate change goals for industrial sectors. Several industries are currently performing various R&D activities and techno economic studies to investigate the most feasible option for CO_2 mitigation. Once the appropriate technology is assessed, developed and deployed, the industrial sectors will have significant impact on achieving global climate change goals to obtain large reductions in CO_2 emissions from various industrial processes such as steel, cement and other heavy industries. Many of these technologies are at early stage of development, however in some industrial sectors it is already deployed in demonstration and large scale. To this effect, examples of the CO_2 mitigation efforts and progress at the RD&D level as well as large-scale application made by some industrial sectors are compiled and presented here.

A.10.1. The Steel industry

Steel industries are a significant source of anthropogenic CO_2 emissions. Although less carbon intensive production routes are emerging, compared to the traditional blast furnace, these are not enough to significantly reduce the process emissions from the steelmaking industry One option to reduce CO_2 emission from these industries without affecting the main iron and steel production process is to apply carbon capture and storage (CCS) technologies on the flue gas from the blast furnace or from collecting that with the fluegas from the basic oxygen furnace and the power plant section. There are several options available, either in pre-combustion or in post-combustion configurations, perhaps the chemical absorption process is the most advanced one, as applied in the Al Reyadah project (Abu Dhabi)

An example of the investigation and deployment of CO_2 capture technology in the steel industries is the H2020 STEPWISE project funded by European Union’s Horizon 2020 research and innovation programme under grant agreement No. 640769. The partners in the STEPWISE consortium represent the whole value chain from technology provider to an industrial end-user from the European steel sector. The consortium represents nine partners from five member states, bringing together technology providers, adsorbent and catalyst manufacturers, system design and engineering companies and industrial end-users. The project aims at the demonstration of an advanced pre-combustion CO_2 removal technology dubbed as Sorption Enhanced Water-Gas Shift technology (SEWGS) within the framework of the Iron and Steel industry and further reduce the risks associated with scaling up of the technology, aiming at lowering the CO_2 footprint of steel production (Gazzani et al., 2015). A similar example is the “COURSE 50” (“**CO_2** **U**ltimate **R**eduction in **S**teelmaking Process by Innovative Technology for Cool **E**arth **50**”) project undertaken in Japan. One of its components is for CO_2 capture technology development for steel industry blast furnace gas (BFG). This project, as stated, “aims at developing technologies to reduce CO2 emissions by approximately 30% through suppression of CO_2 emissions from blast furnaces as well as capture - separation and recovery - of CO_2 from blast furnace gas (BFG), and establishing the technologies by ca. 2030 with the final goal of industrializing and transferring the developed technologies by 2050” (COURSE, undated).

With respect to the large-scale CCS in steel industry, as an example, Emirates Steel has implemented a large-scale CO_2 capture project. In its steel plant, up to 800,000 tons of CO2 is annually being captured which is generated during the iron reduction process and used in a nearby EOR facility, equivalent to planting around 100,000 trees – a massive contribution to Emirates Steel's carbon footprint (Emirates Steel, undated).

A.10.1.1. Technology options

The Al Reyadah project is an operational 0.8Mt/year industrial CO_2 capture plant at Emirates Steel mill at Mussafah, commissioned in 2016. The Emirates Steel site uses a steam methane reformer (SMR) to produce syngas for use in a bauxite direct reduction (DRI) plant, where iron ore is converted to iron for steel making. The fluegas contains CO_2 and H_2O and is separated through a chemical absorption process. The CO_2 is used in EOR.

In the STEPWISE project (SEWGS technology), the CO_2 capture is performed with an advanced CO_2 removal technology making use of regenerative solid adsorbents. The technology combines the conversion of the carbon monoxide into CO_2 and H_2 by reacting it with steam via the Water-gas shift reaction, with the adsorption of the CO_2 on a selective solid adsorbent at elevated temperature. This produces a hot H_2-rich stream at pressure, suitable for power production. Regeneration of the solid adsorbent by means of pressure swing results in a CO_2-rich product, suitable for transport and storage. In the Stepwise project, this process is demonstrated at a scale of 14 t/day CO_2 removal (STEPWISE, 2018).

Through the STEPWISE project, the application of the SEWGS process on steel mill off-gas is investigated and compared to reference traditional chemical absorption and pre-combustion absorption processes. Technical issues associated to the use of the unconventional fuels in state-of-the-art turbines and the effects of steel mill gas blending with natural gas are also evaluated in this project. From the mass and energy balance perspective, the results indicate that the MDEA and SEWGS-based plants allow achieving high CO2 capture efficiencies (of the order of 85–90%), while MEA-based plants need a significant additional heat input to achieve high CO_2 capture levels. In terms of efficiency and specific primary energy consumption for CO_2 avoided (SPECCA), the SEWGS technology with the most advanced sorbent developed allows achieving the highest efficiencies (about 37.7%) and the lowest SPECCA (around 2.2MJ/kg CO_2) among the cases assessed in this project (Gazzani et al., 2015).

The commercial scale Emirates Steel's CO_2 capture project utilizes traditional MEA solvent based absorption system for CO2 capture. The captured CO_2 is then compressed and transported through a pipeline to a nearby EOR facility operated by Abu Dhabi National Oil Company (ADNOC) (Emirates Steel, undated).

Other technologies are under research, such as VPSA (vacuum pressure swing adsorption, seen as a optimistic low cost solution for several steelmaking routes), oxy-firing (as TGROBF, total gas recirculation oxygen blast furnace) and hybrids (combining oxy-firing with chemical absorption or VPSA).

A.10.2. The Cement industry

The most advanced technology for capturing CO_2 in cement plants is chemical absorption. This technique is tested in some industries but to date, almost no cement plants, except one or two, utilize capture technology to mitigate its CO_2 emissions. Extensive pilot scale research and development work for CO_2 capture was initiated by a number of projects. Examples include Norcem AS (Norcem) and its parent company HeidelbergCement Group (HeidelbergCement), who have joined forces with the European Cement Research Academy (ECRA) to establish a small-scale test centre for studying and comparing various post-combustion CO_2 capture technologies and determining their suitability for implementation in modern cement kiln systems. The small-scale test centre was established at Norcem's cement plant in Brevik (Norway) in 2014, and has been used to study various post-combustion carbon capture technologies. The project was launched in May 2013 and concluded by July 2017. The project was financially supported by Gassnova through the CLIMIT-Program. The project mandate involved testing of more mature post-combustion capture technologies initially developed for power generation applications, as well as small-scale technologies at an early stage of development. The project does not cover CO_2 transport and storage.

A large-scale industrial CO_2 capture and utilisation example in cement industry is the Skyonic Carbon Capture and Mineralisation Project (Capitol SkyMine plant) in San Antonio, Texas, United States. The Capitol SkyMine® plant captures 15% of the carbon dioxide emissions from the Capitol Aggregates cement plant and transforms it into materials like baking soda, bleach and hydrochloric acid (Capitol ASggreagates Inv, undated).

A.10.2.1. Technology options

Various technologies for CO_2 capture in cement plants are investigated by different industries. As an example, for a long period of time European Cement Research Academy (RCRA) has been cooperating with the Norcem Brevik cement plant in Norway where different post combustion CO_2 capture technologies are evaluated under realistic conditions. The Norcem project selected four CO_2 capture technologies in Phase I (2013-2014):

- Chemical absorption (Aker Solutions)
- Solid Sorbent Technology (RTI)
- Membrane Technology (DNVGL, NTNU, Yodfat Engineers))
- Calcium looping (Alstom Power)

Two technologies were further studied in Phase II (2015-2016):

- RTI - Solid Sorbent Technology (3. Generation)
- NTNU & Air Products - Membrane Technology (MemCCC) (3. Generation)

Norcem CO_2 Capture Project has been a great success. Both Norcem (the cement industry) and the technology providers have learned much about pilot design and construction, preparation and follow-up of infrastructures, testing on real conditions and based on field-trials-data, calculating the economic performance of the technology.

The project concluded that in a 2022-perspective, only the amine technology provided by Aker Solutions is ready for full-scale demonstration. The technology is tested in real conditions for approximately 8000 testing hours, with good performance results. However it is likely that a palette of technologies will be available and suitable for the cement industry in the future. Local conditions may be decisive when determining which technology should be applied at a given plant.

An important message to technology developers is to start the maturing process today, to be ready for full scale deployment in perhaps 8-10 years-time. A clue is to develop mobile test pilots that can be installed and tested at various real life exhaust gas applications, including cement. Further, the project has shown that capture technologies development is demanding, time consuming and requires considerably resources.

The LEILAC project delivered in 2016 the pre-FEED study, which supported the funding decision in 2017. Currently, the consortium, leaded by Heidelberg Cement and including partners from industry and academia, is constructing a Calix-based system (direct separation CO_2 capture) in Lixhe (Belgium) to run extensive texting during two years, at a feed rate capacity of 240 tonnes per day of raw meal for cement production and 200 tonnes ground limestone respectively. The system will capture the 95% of the process emissions from the cement and limestone production. A techno-economic roadmap and comprehensive knowledge sharing activities are included in the outputs.

There are several research collaborative projects investigating on CO_2 capture technologies at lower development stage. Examples of that are the CEMCAP and CLEANKER projects, both funded by the H2020 programme. The CEMCAP finished in 2018, delivering a techno-economic analysis to compare chemical absorption, oxy-firing, calcium looping, membranes- assisted liquefaction, and chilled ammonia technologies. Oxyfuel showed the most promising economic results. CLEANKER started in 2018 to scale-up the calcium looping

In addition to the CO_2 capture, a number of cement users (e.g. concrete products and ready mix producers) are also currently utilizing CO_2 into the manufacturing process and thus mitigating CO_2through carbon mineralization (CO_2 utilisation). In this approach CO_2 is injected into wet concrete while it's being mixed. Once injected, the CO_2 is chemically converted into a solid mineral and permanently captured within the concrete. This approach of CO_2 mineralization will –not allow CO_2 escaping back into the atmosphere. This technology is already in mature stage and being implemented by a number of cement users. A brief overview of the mineralization process is presented in the Figure A.10.1.

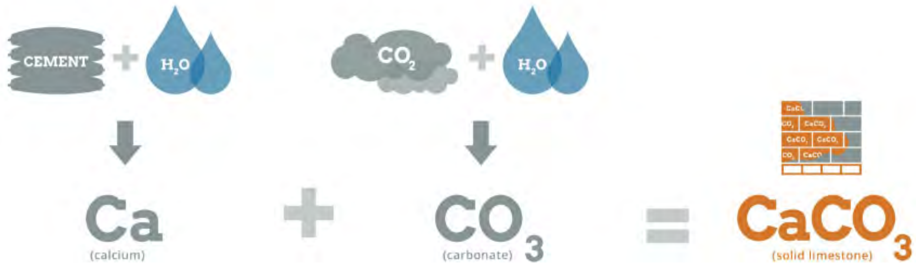

Figure A.10.1. CO_2 mineralization in wet concrete mix (CarbonCure, 2018)

When CO_2 is added to the concrete during mixing, it reacts with water to form carbonate ions. The carbonate then reacts rapidly with calcium ions released from the cement and form nano-size calcium carbonate (limestone) minerals. The conversion of CO_2 into solid calcium carbonate minerals transforms CO_2 into a chemical compound permanently bound within the concrete and thus reduces the CO_2 footprint of the cement industry (CarbonCure, 2018). In another case, though a very slow process, however, during the weathering of concrete CO_2 is absorbed back into cement as it ages and degrades, through the carbonation process.

A.10.3. The Chemical industry

The chemicals sector is a very diverse sector with several processing routes and products. However, there are few key intermediate products, which form the building blocks for most of the chemical products. These can be broadly categorised into organic and inorganic intermediate products. Olefins (ethylene is of particular importance), aromatics and methanol are the key organic intermediates whereas; ammonia, carbon black, soda ash, chlorine and sodium hydroxide are the important inorganic chemicals (Brown et. al., 2012). In recent years chemical industries also have initiated CCUS related proposals and active projects. As an example, Jubail United Petrochemical Company (UNITED), a manufacturing affiliate of SABIC (Saudi Basic Industries Corporation) has installed a large CO_2 purification plant. This plant is designed to compress and purify around 1,500 tonnes per day of raw carbon dioxide coming from two nearby ethylene glycol plants. It can capture and purify up to 500,000 tonnes of CO_2 from the production of ethylene glycol every year and is considered to be the first carbon capture and utilisation (CCU) project undertaken in Saudi Arabia. The project demonstrates how technology can reduce emissions, convert CO_2 into valuable products, and increase operational efficiency, providing SABIC with both short- and long-term economic and environmental gains. The purified CO_2 is routed through a network to other SABIC affiliates, where it is used in the production of useful products, such as urea for agricultural nutrients, liquefied CO_2 for food and drink industry, and methanol, a building block for many other chemicals (Sabic, undated).

A.10.3.1. Technology options

The CO_2 capture in chemical industries can vary widely depending on the chemical processes involved to produce the final product and the CO_2 rich gas generated from the process. All the capture technologies (chemical/physical) either independently or in combination may be applied to capture CO2 in chemical industries.

As an example, the fermentation process produces a stream of relative pure CO_2, making its capture relatively simple, only requiring dehydration and compression of the product stream. Bonanza BioEnergy CCUS EOR Pilot and demonstration CCS facilities in USA capture $CO_2$2 (~ 0.10 Mt/yr) during the ethanol production process. The gas mixture is dehydrated, compressed, and transported, which is used for enhanced oil recovery purposes in the nearby Stewart oil field (CSLF, 2016). The CO_2 capture technology used in Jubail Petrochemical Company is physical separation process. The CO_2 capture process starts with the process gas passing through the pre-cooling and compression stages. Subsequent to the compression, the process gas then passes through various unit operations such as scrubber, dryer (adsorption), and finally to the liquifaction stages to get pure CO_2 which is sent to storage tanks (Linde, udated).

A10.4. The Oil Refining industry

Hydrogen is necessary to upgrade bitumen to lighter oil but making hydrogen creates CO_2. Large quantities of hydrogen are required for refining bitumen for commercial scale plants, which results in a significant potential carbon footprint. However, CO_2 emissions can be mitigated if CCUS can be integrated with refineries, which may bring business values. For example, a bitumen upgrading refinery in Alberta (Canada), Sturgeon Refinery, has been implementing a carbon capture facility to reduce the carbon content of their products. This project is being implemented in collaboration with Enhance Energy [Enhance Energy, undated; North West Refining, undated; Natural Resources Canada, undated-a). Approximately 1.2 million tonnes per year of CO_2 will be captured, from each phase of the project, that would otherwise have ended up in the atmosphere will now be stored in an EOR application. The amount of CO_2 removed will be the equivalent of removing 300,000 cars from the roads every year for the first phase alone. The captured CO_2 will be transported through the Alberta Carbon Trunk Line (ACTL) and will be used to bring oil wells in central Alberta back to life with enhanced oil recovery, creating new economic activities and investment (Alberta Energy, 2018). This will bring benefit both to the industry and to the environment and turn CO_2, into a valuable feedstock. This bitumen refinery is the only one of its kind being built from the ground up to include carbon capture and utilisation technologies and also considered to be first in the world related to CCUS.

A similar project “Quest” was proposed and implemented by Shell in Alberta, Canada. The Quest project required Shell’s Scotford upgrader to be retrofitted for carbon capture and storage. The project is capturing CO_2 from oil sands upgrading and transporting it 65 kilometres north for permanent storage approximately two kilometres below the earth's surface. Quest is designed to capture up to 1.08 million tonnes of CO_2 per year (approximately 35 per cent of the CO_2 produced by the upgrader). The Quest Project is the world’s first application of carbon capture and storage technology at an oil sands upgrader [Alberta Energy, 2018; Natural Resources Canada, udated-b).

A recent H2020 research project, RECAP, modelled the chemical absorption process for several refineries configurations. The consortium delivered a techno-economic analysis on different capture configurations together with a space distribution.

The Lake Charles Methanol (USA), under construction since 2018, is expected to be operational in 2022. The captured CO_2 will be used for EOR and chemicals production. The Teeside project (UK) (waiting for funding decisions to proceed to the next phase), includes the capture of CO_2 from a refinery amongst other industries as part of an industrial cluster project.

A.10.4.1. Technology options

There are three available routes to implement CO_2 capture in refineries: chemical absorption to treat one of several CO_2 stacks; oxy-firing in the burners; and pre-combustion on the gasifiers. The first option is at the highest development stage, and it’s being applied in several running and planned large projects, as described below.

The CO_2 capture system for the Shell Quest project captures CO_2 from the process gas streams of hydrogen-manufacturing units (HMUs) at the Scotford Upgrader. A commercially proven activated amine process is used where CO_2 is absorbed (captured) into the amine solution and then regenerated to produce CO_2 at a purity of at least 95%. The CO_2 is then compressed to a maximum dense-phase pressure of about 12 megapascals and transported through a 12-inch diameter pipeline to a storage site in Alberta. Construction reached mechanical completion on February 10, 2015. Following that, the amine unit as well as the regeneration successfully started up in late May. The compressor and dehydration units were started up in August. The pipeline was filled and injection into the first well was achieved on August 23rd. On September 30th, 2015, Quest received certification for the successful completion of commercial operating tests. The entire system was subsequently handed over to Shell Scotford for sustained operation. The Quest project began commercial operations in November 2015, and in its first three years of operations, Quest has captured and safely stored 3 million tonnes of CO2 Shell Canada, undated).

A.10.5. Hydrogen production

Hydrogen plants are a major source of CO_2 in refineries and chemical plants. It is one of the significant and largest emitters in a typical refinery. As a result, CO_2 capture from hydrogen plants has become important for industries. In hydrogen production, CO_2 is mainly separated as part of the process. However, there are other gas streams, such as reformer flue gas, where CO_2 capture can be implemented. PSA technologies are used for H_2 and CO_2 separation. In some cases, solvent based absorption processes are used utilizing chemical solvents (hot potassium carbonate also known as Benfield process, and amine-based solvents) or physical solvents (Selexol or Rectisol) for CO_2 capture. Membrane based separation and cryogenic purification technologies are also getting more attention in recent years for H2 purification and CO_2 capture. The Tomakomai CCS Demonstration Project, in Japan (~0.10 Mt/yr CO2 capture) captures CO_2 from a hydrogen production unit at Idemitsu Kosan's Hokkaido Refinery at Tomakomai port, Hokkaido. Approximately 100,000 tonnes of CO_2 per annum is injected into two near shore storage sites over the period FY2016-2018, with post-injection monitoring continuing for another two years following termination of injection. CO2 is captured from the PSA off gas containing CO_2 generated from the refinery's hydrogen production unit. The CO_2 is captures by an activated amine solvent-based process. On the other hand, Air Liquide has developed a solution specifically tailored for CO2 capture from SMR plants, which is called CRYOCAP^{TM}H2. This technology uses cryogenic purification to separate the CO_2 from the offgas.

A.10.5.1. Technology options

The technology used in hydrogen industry for CO_2 capture includes adsorbent, solvent based separation (physical/chemical), and in some cases membrane and cryogenic purification processes.

A.10.6. Natural gas production

Natural gas is a mixture of gases. It is typically at least 90 per cent methane and with other hydrocarbons such as ethane and propane. It often also contains gases such as nitrogen, oxygen, carbon dioxide and sulphur compounds; and water (British Geological Survey, 2017). Gas containing small volumes of these impurities can still be used as fuel, but with high volumes cannot be burned efficiently and safely. An example of this type is the natural gas produced at the Sleipner Field in the North Sea. Sleipner is an industrial project in which CCS was implemented as part of a gas field development as the gas in the reservoir contained about 9% CO2 and which needed to be reduced significantly (less than 2.5 per cent) to reach commercial specification.

Another recent development of CO_2 capture from natural gas/LNG processing is the Gorgon Project in Australia operated by Chevron and its partners (CO_2 concentration in natural gas is about 14%). The Gorgon Project is located on Barrow Island, around 60 kilometres off the northwest coast of Western Australia (WA). It includes a three-train 15.6 Mt/year LNG facility and a gas plant with the capacity to supply 300 terajoules of gas per day to Western Australia. The Gorgon project also includes the design, construction and operation of facilities to capture approximately 3.4-4 Mt CO_2/year, inject and store CO_2 into a deep reservoir unit - known as the Dupuy Formation - more than two kilometres beneath Barrow Island for sequestration only. This will reduce GHG emissions from the project by approximately 40 percent and expected about 100 million tonnes of CO_2 to be captured and stored over the life of the project.

A.10.6.1. Technology options

The relatively low concentration of CO_2 in various natural gas reservoirs suggest that an amine base CO_2 capture technology will be a suitable option as the technology is proven and already in use at large scale. As an example, the CO_2 capture in Sleipner field is achieved using a conventional MEA solvent-based capture process, and it was the first project to implement this process on an offshore platform. Since 1996, the Sleipner project in Norway has been separating and capturing CO_2 from a natural gas production and processing facility and injecting it in the Utsira sandstone formation 800-1100 metres beneath the seabed. The project has so far safely and permanently stored approximately over 17 million tonnes of CO_2 since inception to date (Statoil, 2017; the European CCS demonstration Project Network, 2017). There are some other large-scale CO_2 capture projects involving natural gas processing are currently in operation. These include Century Plant (USA), Snøhvit CO_2 Storage, Petrobras Santos Basin Pre-Salt Oil Field CCS etc. A comprehensive list of these projects can be found in other publications [IEA, 2016; GCCSI, 2018). The Gorgon gas field in Australia contains around 14 percent CO_2. In order to liquefy natural gas and to produce LNG it is necessary to cool the natural gas to -162 °C. However, at this temperature if CO_2 remained in the natural gas stream it would freeze solid and potentially plug or damage the liquefaction equipment. For this reason the reservoir CO_2 is separated by an amine absorption technology from the natural gas stream prior to gas processing and liquefaction (Gorgon Project, 2018a; Gorgon Project, 2018b).

A.10.7. Heavy oil production

CO_2 capture in the heavy oil production is increasingly becoming important to make the fuel relatively cleaner. Normally large quantities of steam is required for heavy oil extraction applications where most of the steam is generated through once-through steam generators (OTSG). However, the flue gas from these OTSGs contains significant quantities of CO_2, which is vented. Currently there is no commercial plant available for CO_2 capture from the OTSG flue gas. However, solvent or adsorbent based capture processes will be most suitable for this low pressure and low concentration CO_2 flue gas mixture. A recent pilot demonstration using structured adsorbents to capture CO_2 from OTSG of a SAG) project will make it world's first pilot-scale plant. The compact VeloxoThermTM process developed by "Inventys" will be used for this CO_2 capture.

A.10.6.1. Technology options

Mostly post combustion CO_2 capture processes involving solvent or adsorbent based capture systems will be the technology choice to capture CO_2 from the boiler off gases that produces steam for heavy oil production process.

A.10.8. The Fertilizer industry

Fertilizer plays an important role in improving crop yields on existing farmland. According to the estimate by United Nations (UN), about 40—60% of the world's food production is due to the use of commercial fertiliser. As the world population increases so does the need for fertiliser. Fertilisers usually provide the essential nutrients that crops need to have for a healthy growth. The most important nitrogen-based fertilizer in the world is urea. Basically urea is an eco friendly fertilizer. The production of urea involves the reaction between synthetic ammonia and CO_2 and no additional CO_2 is emitted from the urea process. The CO_2 used in urea production generally comes from the CO_2 generated during the production of ammonia. A conceptual process flow diagram of urea process is Figure A.10.2.

Figure A.10.2. Urea process flow diagram (SETIS, 2018)

Carbon Capture & Storage (CCS) as CO_2 abatement practice, is not performed for any volume of CO2 from fertilizer production. There are two main reasons for this:

- Lack of CO_2capture incentives
- Lack of storage opportunities.

The industry has no incentives today to handle CO_2 differently from current practice. The cost of handling CO_2 cannot be transferred to customers, as ammonia/fertilizer are globally traded products

An existing example of fertilizer with CCS is the Koch Nitrogen Company facility in Enid, Oklahoma, USA. They started CO_2 capture for EOR since 2003 (Koch Fertilizer LLC, undated). Also the Coffeeville Resiurces Nitrogen, Kansas, USA, Fertilizers delivers CO_2 for EOR. The ammonia producer Agrium, Alberta, Canada, will capture 0.58 Mt CO_2/year and transport it via the Alberta Carbon Trunk line (ACTL), for use in several EOR projects (Agrium, 2017; Alberta Energy 2018; Enhance Energy, undated).

A.10.8.1. Technology options

Technologies for CO_2 capture in ammonia production have to be regarded for PROCESS GAS and reformer FLUE GAS. In SMR based ammonia production, about 70% of the CO_2 is generated in the process gas, and 30% in the reformer flue gas.

The reformer flue gas composition resembles somewhat the gas composition from a gas fired power plant, with a slightly higher CO_2 concentration. The solvent-based CO_2 capture technologies, such as amine, might be used. The CO_2 generated in the process gas however, is already captured. The only technology required to make this CO_2 available for export to carbon storage, is a liquefaction and purification plant, and CO_2 storage tanks. The cost of CO_2 removing from the the process gas is indicated to be in the range of 50% of the cost of removing CO_2 from reformer flue gas, depending on assumptions. Liquefaction, purification and storage is required independently of origin of the CO_2.

Another option to reduce the CO_2 emissions in the flue gas from the reformer, is to recycle part of the hydrogen produced as fuel to the reformer. Overall, that would shift CO_2 emissions from the reformer flue gas to the syngas, with lower recovery costs. However, this cost saving on CO_2 recovery must be balanced by the increased cost of a slightly larger SMR unit.

Finally, not directly a capture option, but still a solution that holds a significant CO_2 reduction potential, is feedstock conversion, moving away from coal and heavy fuels, to natural gas, especially in combination with technologies where almost all CO_2 is generated in the process gas. As an example, Yara converted its existing, Partial Oxidation (POX)-based ammonia plant in Germany, which is one of the largest ammonia plants in Europe, from heavy residual fuel oil to natural gas feedstock. The CO_2 emissions were reduced by nearly 50%, or 900.000 t CO_2/year. In addition, the feedstock conversion reduced the emissions of SO_2 and NO_x from the plant by about 50%.

A.10.8.2. Relevance and attractiveness of CCS in ammonia production

Since CO_2 generated in the process gas is already captured as part of the overall ammonia process, handling these volumes seems to be the shortest and most cost effective way to pursue CO_2 reduction via CCS from conventional ammonia production. Provided a CO_2 storage infrastructure is put in place, close to 65-70% of CO_2 emissions from ammonia could be removed at a relatively low cost compared to e.g. power plant CCS or ammonia flue gas CCS.

Furthermore, in hydrocarbon-to-hydrogen process technologies as POX and ATR*, more than 90% of the CO_2 is generated in the process gas. ATR or POX could be chosen instead of SMR for natural gas conversion. SMR is today the dominating hydrogen reforming technology, and considered lowest cost large scale technology. Improvements in ATR and POX could however make such technology preferred hydrogen reformer technology, and by doing so, enabling a relatively low cost removal of close to 90% of the CO_2 emissions from ammonia, without employing other capture technology than the commercial technology supplied as part of the total ammonia plant. In POX/ gasification of coal, almost all CO_2 is also generated in the process gas. The challenge here is that the CO_2 volumes are significantly higher than for natural gas processing, which makes it necessary to scale up CO_2 handling correspondingly.

A.10.9. The Waste-to energy (WtE) industry

There are some initiatives also in place with respect to CO_2 capture in the Waste-to energy (WtE) industry. In Norway, two different capture technologies have been evaluated for CO_2 capture from flue gas generated by waste incineration at the Klemetsrud plant, both based on absorption technology: Aker Solutions' technology based on a proprietary amine, and GE's CAP technology based on chilled ammonia[27]. Both technologies have completed successful test programmes at Technology Centre Mongstad in Norway (TCM) and in other pilot plant. There was a separate initiative from Toshiba Corporation to capture CO_2 from municipal waste incineration process, in Saga Japan. An alkaline aqueous amine solution was used for the CO_2 capture. The Saga City Waste Incineration Plant is capable of capturing approximately 10 tonnes of CO_2 per day from the flue gas of the incinerator. The captured CO_2 will be utilised for crop cultivation and algae culture. In Netherland, Twence is demonstrating an innovative technology for re-using CO_2 by capturing the CO_2 from the flue gases of the waste to energy (WTE) plant and using it for the production of sodium bicarbonate ($NaHCO_3$) as a result of the alkaline reaction with soda (Na_2CO_3). The produced sodium bicarbonate will be used at the waste to energy plant for flue gas cleaning purposes (removal of acid components). This WtE plant produces approximately 8,000 tonnes of sodium bicarbonate annually and contributes to the reduction of CO_2 emissions up to 3,000 tonnes per year (Twence, 2018).

A.10.9.1. Technology options

Post combustion CO_2 capture processes involving solvent (chemical or physical) or adsorbent based CO_2 capture systems will be the desired technology choice at the current state of the waste-to energy industrial facilities.

A.11. Projects related to CCUS activities within industries

There are different technology options for CO_2 capture and utilisation for industries. Each of the CCUS technologies also has associated challenges for implemention at industrial scale. There is a need to address the technology challenges and gaps and make the CCUS option feasible for the industries in order to achieve a realistic CO_2 mitigation approach. Several industries have already come forward with research, development and demonstration plans at pilot scale to large industrial scale projects. A list of various CCUS projects undertaken by different industries is presented in the following section. A graphic representation of the large-scale CCS facilities is presented in Figure A.11.1.

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[27] GE acquired Alstom's chilled ammonia technology and it is on shelf

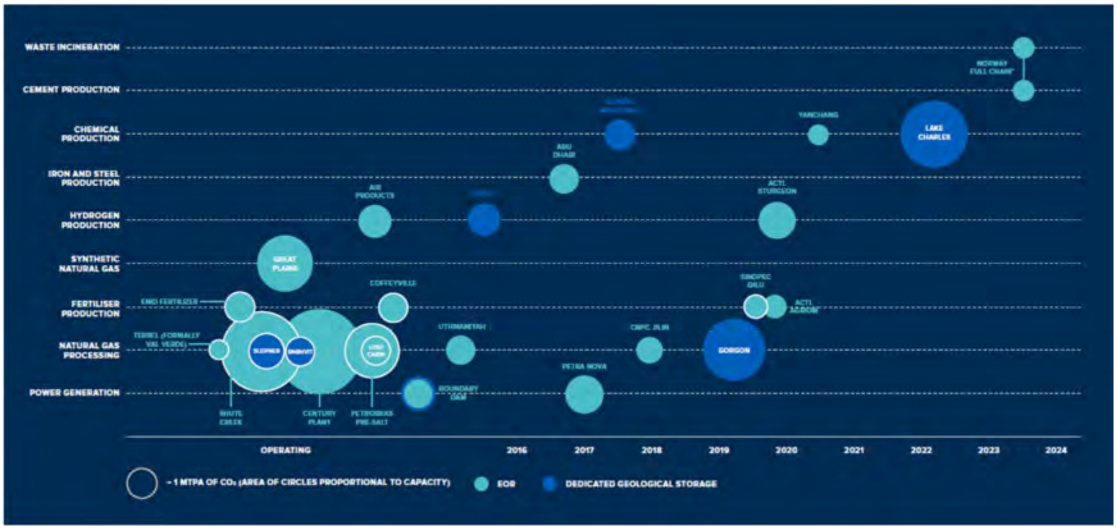

Figure A.11.1. Power and industrial applications of commercial large-scale CCS facilities with actual and expected operation dates up to 2024 (GCCSI, 2018)

The projects are listed based on large-scale projects (>0.4 Mt/yr is considered as large-scale for emissions–intensive industrial facilities including natural gas–based power generation), pilot and demonstration scale projects (0.4<Mt/yr), and CO_2 utilisation projects. This list is created from the information available in public domain (e.g. Global CCS Institute database and IEA data base). A detailed list of different projects can be found elsewhere {IEA, 2016; GCCSI, 2018). However, a partial list, relevant to the scope of this report, is compiled and presented in the next section.

A.11.1. Large Scale Projects

List of Large-Scale CCS Projects (>0.4 Mt/yr) in Industry

Facility Name	Facility Status	Country	Operation Date	Facility Industry	Capture Capacity (Mtpa)	Summary
Steel Industry						
Abu Dhabi CCS (Phase 1 being Emirates Steel Industries)	Operating	UAE	2016	Iron and Steel	0.80 - 0.80	EOR Application
Chemicals and Petrochemicals						
Illinois Industrial Carbon Capture and Storage	Operating	USA	2017	Ethanol Production	1.00 - 1.00	Geological Storage
Lake Charles Methanol	In Development	USA	2022 (estimated)	Chemical Production	4.20 - 4.20	EOR Application
Sinopec Qilu Petrochemical CCS	In Construction	China	2019	Chemical Production	0.40 - 0.40	EOR Application
Yanchang Integrated Carbon Capture and Storage Demonstration	In Construction	China	2020 - 2021	Chemical Production	0.41 - 0.41	EOR Application
Shenhua Ningxia CTL	In Development	China	2020 (estimated)	Coal-to-liquids (CTL)	2.00 - 2.00	
Refining Industry						
Acorn Scalable CCS Development	In Development	UK	2020 (estimated)	Oil Refining	3.00 - 4.00	Geological Storage
Alberta Carbon Trunk Line (ACTL) with North West Redwater Partnership's Sturgeon Refinery CO2 Stream	In Construction	Canada	2019	Oil Refining	1.20 - 1.40	EOR Application
Hydrogen Production						
Air Products Steam Methane Reformer	Operating	USA	2013	Hydrogen Production	1.00 - 1.00	EOR Application
HyNet North West	In Development	UK	2020 (estimated)	Hydrogen Production	1.50 - 1.50	Geological Storage
Northern Gas Network H21 North of England	In Development	UK	2026	Hydrogen Production	1.50 - 1.50	
Quest	Operating	Canada	2015	Hydrogen Production	1.00 - 1.00	Geological Storage
Natural Gas Production						
Century Plant	Operating	USA	2010	Natural Gas Processing	8.40 - 8.40	EOR Application
CNPC Jilin Oil Field CO2 EOR	Operating	China	2018	Natural Gas Processing	0.60 - 0.60	EOR Application
Gorgon Carbon Dioxide Injection	In Construction	Australia	2019	Natural Gas Processing	3.40 - 4.00	Geological Storage
Great Plains Synfuels Plant and Weyburn-Midale	Operating	Canada	2000	Synthetic Natural Gas	3.00 - 3.00	EOR Application
In Salah CO2 Storage	Completed	Algeria	2004	Natural Gas Processing	0.00 - 0.00	Storage in depleted gas reservoir
Lost Cabin Gas Plant	Operating	USA	2013	Natural Gas Processing	0.90 - 0.90	EOR Application
Petrobras Santos Basin Pre-Salt Oil Field CCS	Operating	Brazil	2013	Natural Gas Processing	1.00 - 2.50	EOR Application
Shute Creek Gas Processing Plant	Operating	USA	1986	Natural Gas Processing	7.00 - 7.00	EOR Application
Sleipner CO2 Storage	Operating	Norway	1996	Natural Gas Processing	1.00 - 1.00	Geological Storage
Snøhvit CO2 Storage	Operating	Norway	2008	Natural Gas Processing	0.70 - 0.70	Geological Storage
Terrell Natural Gas Processing Plant (formerly Val Verde Natural Gas Plants)	Operating	USA	1972	Natural Gas Processing	0.40 - 0.50	EOR Application
Uthmaniyah CO2-EOR Demonstration	Operating	Saudi Arabia	2015	Natural Gas Processing	0.80 - 0.80	EOR Application
Fertilizer Production						
Alberta Carbon Trunk Line (ACTL) with Agrium CO2 Stream	In Construction	Canada	2019	Fertilizer Production	0.30 - 0.60	EOR Application
Coffeyville Gasification Plant	Operating	USA	2013	Fertilizer Production	1.00 - 1.00	EOR Application
Enid Fertilizer	Operating	USA	1982	Fertilizer Production	0.70 - 0.70	EOR Application
Sinopec Eastern China CCS	In Development	China	2020-2021	Fertilizer Production	0.50 - 0.50	EOR Application

**** Data Source: Global CCS Institute – Global CCS intelligence database (CO2RE: https://co2re.co/FacilityData)**

A.11.2. Pilot and Demonstration Scale CCS ProjectsPilot and Demonstration Scale Projects

(0.4<Mt/yr) in Industry

Facility Name	Facility Status	Country	Operation Date	Facility Industry	Capture Capacity (Mtpa)	Summary
Steel Industry						
COURSE 50 - CO2 Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50	Operational	Japan		Iron and Steel Production	0.01 - 0.01	
STEPWISE Pilot of SEWGS Technology at Swerea/Mefos	Operational	Sweden	2007	Iron and Steel Production	0.00 - 0.00	
Cement Industry						
CEMCAP	Completed	Multiple	2015	Cement Production		
CO2 Capture Test Facility at Norcem Brevik	Completed	Norway	2013	Cement Production		
ITRI Calcium Looping Pilot	Operational	China	2013	Cement Production	0.00 - 0.00	
LEILAC	In Construction	Belgium	2020 (estimated)	Cement Production	0.08 - 0.08	
Chemicals and Petrochemicals						
Sinopec Zhongyuan Carbon Capture Utilization and Storage Pilot Project	Operational	China	2006	Chemical Production	0.12 - 0.12	EOR Application
Carbon Clean Solutions Solvay Vishnu Capture Project	Completed	India	2012	Chemical Production	0.00 - 0.00	
Arkalon CO2 Compression Facility	Operational	USA	2009	Ethanol Production	0.17 - 0.29	EOR Application
Bonanza BioEnergy CCUS EOR	Operational	USA	2012	Ethanol Production	0.10 - 0.10	EOR Application
Farnsworth Unit EOR Field Project - Development Phase	Operational	USA	2013	Ethanol Production and Fertilizer Production		EOR Application
Husky Energy Lashburn and Tangleflags CO2 Injection in Heavy Oil Reservoirs Project	Operational	Canada	2012	Ethanol Production	0.08 - 0.08	Enhanced Recovery of Heavy Oil
Illinois Basin Decatur Project (CO2 Injection Completed, Monitoring Ongoing)	Completed	USA	2011	Ethanol Production	0.33 - 0.33	Geological Storage
Karamay Dunhua Oil Technology CCUS EOR Project	Operational	China	2015	Methanol Production	0.10 - 0.10	EOR Application
Shenhua Group Ordos Carbon Capture and Storage (CCS) Demonstration Project	Completed	China	2011	Coal-to-liquids (CTL)	0.10 - 0.10	Geological Storage
PetroChina Changqing Oil Field EOR CCUS	Operational	China	2017	Coal-to-liquids (CTL)	0.05 - 0.10	EOR Application
Refining Industry						
Chinese-European Emission-Reducing Solutions (CHEERS)	In Development	China	2022	Oil Refining		
Inventys and Husky Energy VeloxoTherm Capture Process Test	In Development	Canada	2018	Oil Refining	0.01 - 0.01	Enhanced Recovery of Heavy Oil
Hydrogen Production						
Hydrogen Energy Supply Chain (HESC) project	In Development	Australia	2020 - 2021	Hydrogen Production		
Tomakomai CCS Demonstration Project	Operational	Japan	2016	Hydrogen Production	0.10 - 0.10	Geological Storage
Natural Gas Production						
Bell Creek - Incidental CO2 Storage Associated with a Commercial EOR Project	Operational	USA	2010	Natural Gas Processing		EOR Application
CO2CRC Otway	Operational	Australia	2008	Natural Gas Processing	0.01 - 0.01	Geological Storage
Core Energy CO2-EOR	Operational	USA	2003	Natural Gas Processing	0.30 - 0.35	EOR Application
K12-B CO2 Injection Project	Completed	Netherlands	2004	Natural Gas Processing	0.03 - 0.03	Storage in Depleted Gas Reservoir
Gundih CCS Pilot	In Development	Indonesia	2018	Natural Gas Processing		EOR/Storage
Michigan Basin (Phase II) Geologic CO2 Sequestration Field Test	Completed	USA	2008	Natural Gas Processing	0.01 - 0.05	Geological Storage
Michigan Basin Large Scale Injection Test	Operational	USA	2013	Natural Gas Processing	0.18 - 0.24	EOR Application
Nagaoka CO2 Storage Project	Completed	Japan	2003	Natural Gas Processing	0.00 - 0.00	
Pembina Cardium CO2 Monitoring Pilot	Completed	Canada	2005	Natural Gas Processing	0.02 - 0.03	EOR Application
Zama Field Validation Test	Completed	Canada	2005	Natural Gas Processing	0.01 - 0.01	
CNPC Jilin Oil Field EOR Demonstration Project		China	2008	Natural Gas Processing	0.1 - 0.35	EOR Application
Fertilizer Production						
Miranga CO2 Injection Project	Completed	Brazil	2009	Fertilizer Production	0.12 - 0.12	
PCS Nitrogen	Operational	USA	2013	Fertilizer Production	0.20 - 0.30	EOR Application
Borger CO2 Compression Facility	Completed	USA	2001	Fertilizer Production	0.22 - 0.33	EOR Application

**** Data Source: Global CCS Institute – Global CCS intelligence database (CO2RE: https://co2re.co/FacilityData)**

A.11.3. CO$_2$ Utilisation Projects

Facility Name	Facility Status	Country	Operation Date	Facility Industry	Capture Capacity (Mtpa)	Summary (CO2 Utilization)
Steel Industry						
ArcelorMittal Steelanol	In Construction	Belgium	mid-2020s	Iron and Steel	0.15 - 0.15	Bioethanol
Cement Industry						
Skyonic Carbon Capture and Mineralisation Project	Operational	USA		Cement Production		Sodium bicarbonate production
Chemicals and Petrochemicals						
SABIC Carbon Capture and Utilisation Project	Operational	Saudi Arabia		Chemical Production	0.40 - 0.50	Methanol, Chemical and Urea production
The Valorisation Carbone Québec (VCQ) Projec	In Construction	Canada	2019	Chemical Production	0.00 - 0.00	
CO2 Utilisation Plants using the KM CDR Process®	Operational	Multiple		Industrial Applications		Industrial/Methanol production
Hydrogen Production						
Port Jérôme CO2 Capture Plant	Operational	France	2015	Hydrogen Production	0.10 - 0.10	
Fertilizer Production						
Alcoa Kwinana Carbonation Plant	Operational	Australia		Fertilizer Production		Carbonation
Waste to Energy (WtE) Industry						
Saga City Waste Incineration Plant	Operational	Japan	2016	Waste Incineration	0.00 - 0.00	Crop cultivation and Algae culture
Twence Waste-to-energy CO2 Capture and Utilisation	Operational	Netherlands	2014	Waste Incineration	0.00 - 0.00	Sodium bicarbonate production
Other Industries						
CO2 Utilisation Plants - Europe	Operational	Multiple		Industrial Applications		
CO2 Recovery Plants in China	Operational	China		Industrial Applications		Food and Beverage
CO2 Utilisation Plants - North America	Operational	Multiple		Industrial Applications		
CO2 Utilisation Plants - Oceania Region	Operating	Multiple		Various		Food and Beverage and Industrial application
CO2 Utilisation Plants using the Fluor Econamine FG Process	Operational	Multiple		Various		
Saint-Felicien Pulp Mill and Greenhouse Carbon Capture Project	Operational	Canada	2018	Pulp and Paper Production	0.01 - 0.01	Vegetable Greenhouse
**** Data Source: Global CCS Institute – Global CCS intelligence database (CO2RE: https://co2re.co/FacilityData)**						