



DET NORSKE VERITAS

Global Technology Roadmap for CCS
in Industry
Sectoral Assessment: Refineries

Report No./DNV Reg No.: / 12P5TPP-9

Draft Rev 3, 2010-08-25



Global Technology Roadmap for CCS in Industry	DET NORSKE VERITAS LTD, UK Palace House SE19DE London, United Kingdom Tel: +44 (0)20 7357 6080 Fax: +44 (0)20 7357 6048 http://www.dnv.com Org. No: GB 440 6013 95
Draft Research Report For: United Nations Industrial Development Organization (UNIDO) Vienna International Centre PO Box 300, A-1400 Vienna, Austria	
Account Ref.:	

Date of First Issue:	2010-07-2825	Project No.:	EP024621
Report No.:		Organisation Unit:	Wind Energy, CCS and Power Generation
Revision No.:	3	Subject Group:	

Summary:

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Key Words

Service Area

Market Segment Carbon Capture and Storage |
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Rev. No. / Date:	Reason for Issue:	Prepared by:	Verified by:	Accepted by:
Rev 2 / 2010-07-29	Removed UNIDO from cover	JWB	PH	DB
Rev 3 / 2010-08-26	Updated with UNIDO reviewers comments	JWB	PH	DB

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SUMMARY

This report provides an overview of the potential application of carbon capture and storage technologies to refineries. It describes the industry today, including its CO₂ emissions and goes on to analyse various ways in which CO₂ capture technology could be applied. It looks at legislative influences, costs and concludes by identifying challenges and recommended next steps. Transport and storage aspects of CCS are only touched upon as they are common with other industries.

At best, the refining of conventional crude will grow slowly, particularly in the Middle East and Asia, as predicted by OPEC in the decades out to 2050. However in the IEA BLUE map scenario which is considered to offer the opposite end of the spectrum in terms of predictions for the refining industry, the industry may shrink considerably over the same period, as demand decays and conventional liquid fuels are replaced by non-conventional sources. Non-conventional sources include natural gas liquids (NGLs), gas to liquids (GTLs), coal to liquids (CTLs) and biofuels. It is likely that the emission intensity of the refining industry will increase during this period due to the use of heavier crudes and tighter specifications for product quality. Despite this, in the long term to 2050 there is also the possibility that absolute emissions may decline because the outlook for the refining industry is uncertain: Non-conventional fuels pose a real threat to supply of conventional liquids and hence refining in the short term and climate abatement policy will play a role. In the period up to 2030, it is likely that any growth in the refining sector will be in the Middle East and Non-OECD Asia-Pacific with little in Europe and North America. Transport related emissions including refining in China, India and rest of world including Middle East, Africa and Latin America have potential to grow to 2050, hence there is potential for greenfield CCS deployment in refineries of these regions. In the same period to 2050 more established markets such as the OECD, potential CCS deployment may be for retrofit of existing refineries.

CCS is a technology that offers carbon abatement for the combustion of fossil fuels. In the refining industry perspective, it is unclear how much of a role it will play in the long term (to 2030) due to the comparably high cost of capture, tight refining margins and multiple different CO₂ sources on a refining site. Adding to this uncertainty are major studies such as the Energy Technology Perspectives and Technology Roadmap for CCS from the IEA, which do not specify the role of CCS in the refining sector. There are, however, existing publicly funded demonstration projects underway in the sector, such as those at Mongstad, Rotterdam, Port Arthur and Edmonton. McKinsey and Company suggest CCS will be an appropriate technology for carbon abatement in oil and gas sectors of Western Europe and North America to 2030.

Of the CCS technologies, post-combustion technology offers potential for refineries in the near future. However, in the longer term and as these technologies develop; other promising technologies may develop for lower cost deployment: Hydrogen production using either heavy residue gasification or steam methane reforming with chemical absorption separation produces a high purity CO₂ stream that seems to be the lowest cost capture option at ~€30/tCO₂ avoided. The cost of CO₂ capture will be greater for refineries producing high purity hydrogen using pressure swing absorption, because the CO₂ produced requires further processing to reach economic specifications required for transport and storage. The energy penalty resulting from capture is a major influence on the avoided cost of CO₂ capture, as is the space requirement for capture and transport technology on a refinery site. Post combustion technology exists for heaters, boilers, fluid catalytic crackers and utilities, but at much higher costs (>€80/tCO₂ avoided). Oxy-firing technology is a promising technology but lags post combustion technology in that it remains untested on the scales required for commercial deployment. Pre-combustion technology also has potential in a refinery because of the smaller CO₂ sources, but again the development of this technology lags post-combustion. Although not a focus of this assessment, transport and storage have a large influence on the cost of the CCS chain and are specific to each site. Given that the absolute amount of CO₂ emitted is smaller than



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from power stations, CCS for refineries could benefit from the scale economy of CO₂ transport and storage network infrastructure.

In conclusion, the outlook for CCS in the refining industry is mixed. Technology exists that could be deployed, but cost and complexity is a barrier for capture at most point sources on a refinery, with capture on certain hydrogen production processes being the notable exception of limited materiality. Policy that could lead CCS in the refining sector has the potential to also reduce the demand for transport fuels, and reduce the output and emissions from the refining sector. Supporting CCS in the refining sector would have to include support for new technologies that could substantially reduce the deployment costs for many units of a refinery. Planned publicly funded CCS demonstrations at a number of sites around the world are a step towards this. The longer term outlook to 2050 for the refining sector on the whole is even less certain with demand for liquid fuels potentially being eroded by use of non-conventional sources and carbon abatement policy.

Notwithstanding the uncertain future for the refining industry on the whole there are measures that have potential to overcome the barriers to CCS deployment in the refining sector and reduce uncertainty. A comprehensive emissions inventory can be developed and standard methodologies for calculating emissions universally accepted. This will could either include or lead to characterisation of the unique emissions of each unit operation. As an outcome, emissions abatement with lower cost than CCS could be identified and addressed to reduce potential capture inventories. There is also existing information and experience for CCS and related processes specific to the refinery sector, which could be consolidated and disseminated globally. On top of this commercial demonstration of CCS technology in a refining setting could also help reduce the uncertainty.

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ABBREVIATIONS

API	– American Petroleum Institute
bbbl	– Barrel of oil
bbbl/d	– Barrels of oil per day
BREF	– Best Available Technology Reference Document
CAPEX	– Capital Expenditure
CAP	– Chilled Ammonia Process
CCP	– CO ₂ Capture Project
CDM	– Clean Development Mechanism
CCS	– Carbon Capture and Storage
CHP	– Combined Heat and Power Generation
CO ₂	– Carbon Dioxide
CTL	– Coal to Liquids
EERP	– European Economic Recovery Program
EIPPCB	– European Integrated Pollution Prevention and Control Bureau
ETS	– Emissions Trading Scheme
EU	– European Union
EU ETS	– European Union Emissions Trading Scheme
EU NER300	– European Union New Entrants Reserve allocation of 300 million carbon credits
FCC	– Fluidised Catalytic Cracker
GHG	– Greenhouse Gas
GTL	– Gas to Liquids
H ₂	– Hydrogen
HCC	– Hydro Catalytic Cracker
HDT	– Hydro-treating unit
IEAGHG	– International Energy Agency Greenhouse Gas Research and Development Programme
IEA	– International Energy Agency
IMO	– International Maritime Organization
IPCC	– International Panel on Climate Change
IPIECA	– International Petroleum Industry Environmental Conservation Association
MARPOL	– Marine Pollution
Mbbl/d	– Million barrels of oil per day
MDEA	– Methyl-diethanolamine



MEA – Monoethanolamine

MtCO₂ – Million tonnes of CO₂

NGL – Natural Gas Liquids

NO_x – Oxides of Nitrogen

NPRA – National Petrochemical and Refiners Association

LPG – Liquefied Petroleum Gas

OECD – Organisation for Economic Co-operation and Development

OPEC – Organization of Petroleum Exporting Countries

ppm – Parts per million

PSA – Pressure Swing Absorption

RCI – Rotterdam Climate Initiative

SCR – Selective Catalytic Reduction

SECA – SO_x Emissions Control Area's

SMR – Steam Methane Reforming

SO_x – Oxides of Sulphur

TCM – European CO₂ Technology Centre Mongstad

UNFCCC – United Nations Framework Convention on Climate Change

UNIDO – United Nations Industrial Development Organization

UK – United Kingdom

US – United States of America

US DOE – United States of America Department of Energy

WPC – World Petroleum Council



1 INTRODUCTION

Crude oil refineries are responsible for the separation and processing of crude oil to make more valuable petroleum products such as liquid petroleum gas (LPG), naphtha, gasoline, jet fuel, diesel fuel, and heating oil. Modern refineries have a range of integrated processes such as distillation, reforming, cracking and hydrotreating, all of which require significant heat input via fuel combustion. The fuel utilized in the process heaters, reactors and steam boilers comprise of petroleum coke, process (still) gas, petroleum fuels and natural gas (Rootzen et al. 2009).

CO₂ emissions from refineries reportedly account for about 6% of global stationary CO₂ emissions (IPCC, 2005) or nearly 1 billion tonnes of CO₂ per year (IEAGHG, 2008). However, these figures are widely debated and are the topic of further discussion later in this assessment. According to van Straelen et al. (2009), a typical large-scale (300,000 barrel per day) refinery will produce between 0.8 and 4.2 million tCO₂/y. Energy use and CO₂ emissions vary depending on processed crude, extent of processing, and quality and composition of the product mix.

This assessment will be used as a basis for drafting a CCS roadmap for industrial processes, including refineries, and will form the basis for identifying the steps that need to be undertaken to expand industrial CCS from where it is today to 2050, to help achieve global GHG emission reduction targets. The assessment will include a status of the technology in the refining sector as well as the trends and prospects for deployment of CCS in developing regions out to 2050. The report will focus on:

- characterising the global refining industry
- current and projected refining industry emissions of the refining sector
- technical assessment of technology for CO₂ capture in refineries
- current and potential use of CCS in refining sector
- estimated costs of capturing CO₂ generally and more specifically for the refining sector.
- legislative pressures relating to the refining sector
- identifying barriers to implementation of CCS in the refining sector
- actions and milestones to implement CCS in the refining sector

2 CHARACTERISTICS OF THE REFINING SECTOR

There is no such thing as a typical refinery; the configurations and processes in each being dependent on a number of factors including: the crude feed composition, the product demand, local regulations and economics. The 661 oil processing complexes considered refineries by the 2009 Worldwide Refining Survey (Koottungal, 2009) have a combined capacity of 87,223,000 bbl/d (barrels of oil per calendar day) and range in size from 1,500 bbl/d (Ulyanovskneft, Russia) to 940,000 bbl/d (Paraguana Refining Centre, Venezuela). The world average is 132,000 bbl/d, with slightly higher averages in the OECD nations at 140,000 bbl/d, and OPEC nations at 167,000 bbl/d. There has been a trend in the past two decades to reduce the number of refineries, but increase the capacity; between 1993 and 2007, the average size of refineries increased by 30% (Purvin and Gertz, 2008).

Table 1: Imports and exports of mineral crude oil and refined products around the world in 2009. Source: BP Statistical Review of World Energy 2010.

Country	Million barrels daily			
	Crude	Product	Crude	Product
	Imports	Imports	Exports	Exports
US	8.89	2.55	0.04	1.87
Canada	0.79	0.32	1.94	0.54
Mexico	0.01	0.44	1.28	0.17
S. & Cent. America	0.50	0.86	2.59	1.14
Europe	10.31	3.18	0.46	1.52
Former Soviet Union	0.02	0.07	6.87	2.20
Middle East	0.14	0.22	16.51	1.92
North Africa	0.37	0.21	2.23	0.53
West Africa	0.00	0.25	4.26	0.11
East & Southern Africa	0.44	0.12	0.30	0.01
Australasia	0.46	0.36	0.26	0.04
China	4.09	1.04	0.09	0.61
India	2.93	0.22	0.00	0.74
Japan	3.54	0.74	-	0.35
Singapore	0.93	1.67	0.05	1.51
Other Asia Pacific	4.59	2.67	0.81	1.25
Unidentified *	-	0.02	0.31	0.43
Total World	38.00	14.92	38.00	14.92

The capacity of the world's refining sector is generally closely related to the world oil demand, as shown in Figure 1, with oil primarily being converted to transportation fuels. An upward trend in demand in the past two decades can be seen, following on from the oil shocks of the 1970s. Despite the correlation between refinery throughput and oil consumption on a global level, this is not necessarily reflected at a regional level, as shown by imports and exports of crude oil and refined products in Table 1. There is a trend for the major oil producing regions, such as Russia and Middle East to export refined products, although these are in smaller quantities than exports of crude oil. Changing consumption patterns, such as the reduction in gasoline usage and increase in kerosene (jet fuel) and diesel usage in Europe has led to increased kerosene and diesel importation, mainly from Russia and export of gasoline to the US and the Middle East. Additional capacity is expected to come online in the US in the period to 2020, however, most refinery additions required to meet demand are likely to take place in the Middle East and Far East (Purvin and Gertz Inc., 2008). OPEC (2009) reiterates this and predicts that to 2020, 47% of capacity additions will come in the Non-OECD Asia Pacific region and 22% in the Middle East, while in the period up to 2030, 57% are predicted in the non-OECD Asia-Pacific region and 18% in the Middle East. Figure 2 shows the annual investment in different regions of the world, indicating where growth in refining capacity has taken place in the past decade.

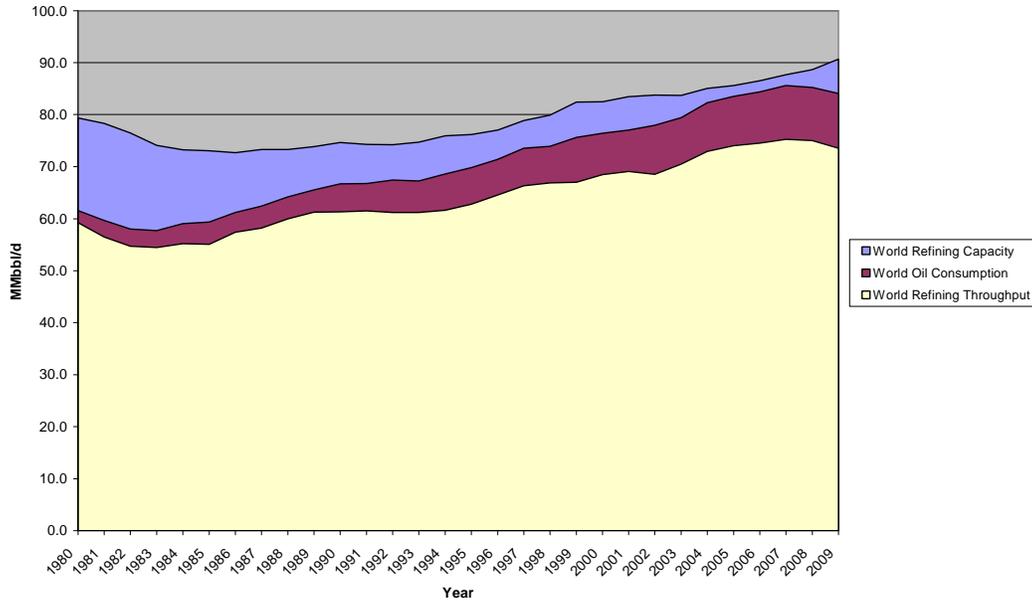


Figure 1: Refining capacity and throughput in relation to world oil consumption since 1980.
 Source: BP Statistical Review of World Energy 2010.

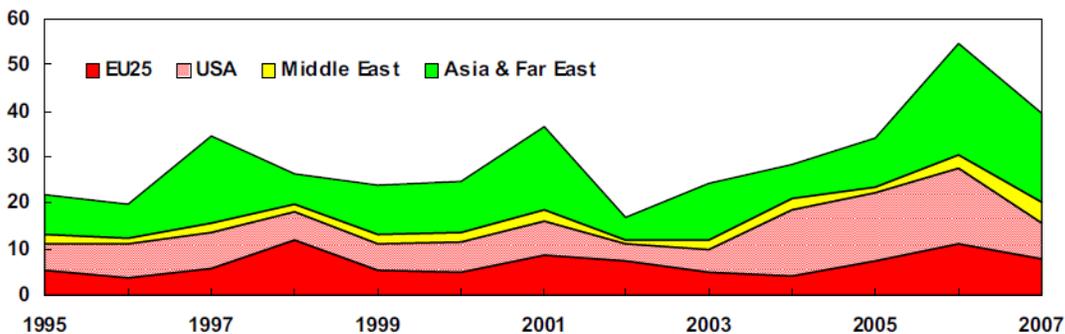


Figure 2: Refining industry annual investment by region from 1995 to 2007 in Billion US\$.
 Source: Purvin and Gertz, 2008

The world's refining capacity is made up of a mixture of International oil companies, National oil companies, and smaller local companies. Concentration in the refining industry is fairly low – e.g. the top 25 refinery owners, operate little more than 50% of the capacity (Reuters, 2008). In saying that, the top ten refining companies include five super major oil companies: ExxonMobil, Royal Dutch Shell, BP, ConocoPhillips and Total and these ten make up 36% of the world's capacity. The national oil companies of Venezuela, China and Saudi Arabia, also feature on the list of the top ten, but in contrast to the super majors, these companies operate almost exclusively in their own country. Note that Table 2 is possibly misleading, as a number of joint venture companies operate separately from their parent organisation. An example of this is Motiva Enterprises LLC, which is a 50/50 joint



venture between Saudi Aramco and Shell, and which has refining capacity of 762,000 bbl/d, making it the world's 25th largest refining company.

Table 2: Top 10 refining companies by capacity in bbl/d. Source: Reuters (2008)

Rank	Company	Capacity [bbl/d]	Percentage of World Capacity
1	ExxonMobil	5,357,850	6.1
2	Sinopec	4,210,917	4.8
3	Royal Dutch Shell	3,985,129	4.6
4	BP	3,231,887	3.7
5	ConocoPhillips	2,799,200	3.2
6	Petroleos de Venezuela (PDVSA)	2,642,600	3.0
7	PetroChina	2,607,407	3.0
8	Valero Energy Corp	2,422,590	2.8
9	Saudi Aramco	2,005,000	2.3
10	Total	1,934,733	2.2

2.1 Outlook for Refining Sector

The refining sector has uncertain times ahead with the current financial crisis, non-conventional liquid fuels, and climate policy potentially impacting the sector. In the early part of the decade, 2002-2006, the refinery market was particularly tight due to historic lack of investment and low margins and a sudden surge in demand. This led to a surge in investment and capacity, which is leading to an over supply of refining capacity in light of the recent financial crisis. In the 2008 World Energy Outlook, OPEC predicted that in 2015 the worldwide refinery utilization would be 84.4%, while following the financial crisis in 2009, OPEC predicted 2015 utilization rates of 76.6% (OPEC, 2009). This predicted decline in utilization comes on the back of especially large demand drops in the OECD, that probably will imply widespread consolidation and closures to restore operating rates and refinery viability (OPEC, 2009).

The refining industry globally is set to be dramatically affected in coming decades by new supplies of non-conventional liquid fuels and also by the demands of climate change abatement policy. Excluding biomass, non-conventional oil supplies including oil sands, natural gas liquids (NGLs), synthetic oil from shale oil, natural gas (GTLs) and coal (CTLs) are likely to impact the refining industry going forward. Non-conventionals such as NGLs, GTLs, CTLs and biofuels require less mainstream refining and will potentially have a negative impact on the industry, while synthetic oil from shale oil and oil sands still require extensive processing. The OPEC (2009) projections for the supply of crude and other non-conventionals are summarised in Table 3. Supply of NGLs and condensates in 2008 was 9.8Mbbbl/d and is expected to be 11.5 Mbbbl/d by 2013. Oil sands production totalled 1.2 Mbbbl/d in 2008 and is expected to reach 1.6 Mbbbl/d in 2013, mainly from Canada (OPEC, 2009). Current supplies of shale oil total 10,000 bbl/d with little expectation of short term growth. GTLs production is about 50,000 bbl/d, however, this is set to expand substantially with an additional 140,000 bbl/d coming on line in Qatar in 2011 (Shell, 2010). Supply of CTLs was 160,000 bbl/d in 2008 and is expected to increase to 300,000 bbl/d in 2013, with these increases mainly in China, South Africa and US (OPEC, 2009). Non-conventional supplies excluding NGLs and biofuels are expected to grow



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from 1.8 Mbb/d in 2008 to 6.0 Mbb/d in 2030. Although this growth is much faster than conventional oil markets, it still is only the equivalent of twenty 300,000 bbl/d refineries. In the short term the impact of NGLs and condensates on the refining industry is expected to be the greatest of all the non-conventionals and may lead to a decline in the prices of gasoline and naphtha. This will lead to a decrease in the need for secondary processing such as FCC. In the longer term there is expected to be substantial growth in other non-conventionals, which leads to a slight growth in absolute terms for crude, but a large decline in demand for refined products as a share of total supply.

Table 3: World oil supplies from crude, NGLs and other non-conventionals to 2030. Source: OPEC, 2009

	2008	2013	2020	2030
Total Crude [Mbb/d]	72.9	72.3	75.0	79.5
Total NGLs [Mbb/d]	9.8	11.5	13.5	15.2
Total Non-Conventionals	3.1	4.2	6.8	10.7
Total World Supply [Mbb/d]	85.8	88.2	95.7	105.9
% Crude of Total	85.0	82.0	78.4	75.1
% NGLs of Total	11.4	13.0	14.1	14.4
% Non-conventionals of Total	3.6	4.8	7.1	10.1

The climate change debate is affecting the refineries industry: part of the predicted climate abatement policies will be to introduce biofuels to replace crude-based fuels, and part will be to reduce demand. The future impact of biofuels is expected to be led by bio-diesel use in Europe on the back of the 2009 EU Renewable Energy Directive. The Directive obliges EU members to have 10% transport fuel from renewable sources by 2020, however, it must be noted that the requirement of a previous directive to have 2% by 2005, was not met. Biofuel use in the US and Latin America is also expected to grow substantially in the coming decades, which will also impact refining in those regions. By 2020, Purvin and Gertz, (2008) expect the world demand to be 100,000t/y. OPEC (2010) state that in 2008 there was 1.3 Mbb/d of biofuel production and this is expected to grow by 0.7 Mbb/d between 2008 and 2013, mainly in US, Brazil and China. In the long term to 2030, OPEC predict demand will reach 4.7 Mbb/d. Note however, that there is an ongoing debate regarding biofuels' climate credentials: E.g. in Lange (2010) there is evidence that suggests changing land use for certain bio-fuel's production does not actually reduce global emissions, whilst for other it has a reduced abatement impact. The exception to this is using existing crop land for biofuel, which has implications for the food chain. This adds to the pressure on unproven second generation biofuels technology.

In its Energy Technology Perspectives report (IEA, 2010), the IEA has forecast transport energy use in scenario's where no climate abatement policy exists (baseline) and for scenario's with different carbon abatement policy trends (BLUE). In the scenario that growth in fuel usage continues without any policy interventions in the baseline scenario (Figure 3), the IEA (2010) expects conventional liquid fuels for transport could increase. In a worst case which includes strong growth in the light passenger vehicles of the high baseline scenario this could be by as much as 40 Mbb/d in the period to 2050. The concept of peak oil is not universally agreed upon by all stakeholders but may mean that such a rise in production is not possible, as suggested by UK Industry Taskforce on Peak Oil & Energy Security (Roberts, 2010). Policy that could lead to CCS applications in the refining sector has the potential to also reduce the demand for transport fuels, and to reduce the output and emissions

from the refining sector. In this case changes of mode of transport, reduction in miles traveled, electrification of the small vehicle fleet and use of hydrogen and biofuels could erode demand for traditional refinery products. Abatement described in the IEA's so-called BLUE map scenario aims to maintain long term global temperature rises within 2°C to 3°C range, by reducing 2005 CO₂ emissions by half in 2050 with changes in transport technology. In the BLUE map world, crude oil demand is expected to fall by 27% compared with 2007, although the exact implication for the refining sector is not defined. Demand for Gasoline, Diesel, Jet fuel and Heavy fuel oil, all fall considerably under this scenario, which will heavily influence the refining industry throughput (see Figure 3). It is possible that the actual demand in 2050 will lie somewhere between the two scenarios described. The weight of evidence from all the sources reviewed suggests demand for conventional refined products is likely to ease, nevertheless business as usual predictions such as that described by the IEA (2010) indicate a large amount of uncertainty for the refining sector and its investors. With reference to Figure 3, the BLUE shifts scenario assumes a change in transport modes to more efficient modes, with slight reduction in growth and the BLUE map / shifts scenario combines the technology changes of the BLUE map with the changes in travel patterns of the BLUE shifts scenario. These scenarios further emphasize the potential carbon abatement policy has to reduce demand for refinery products.

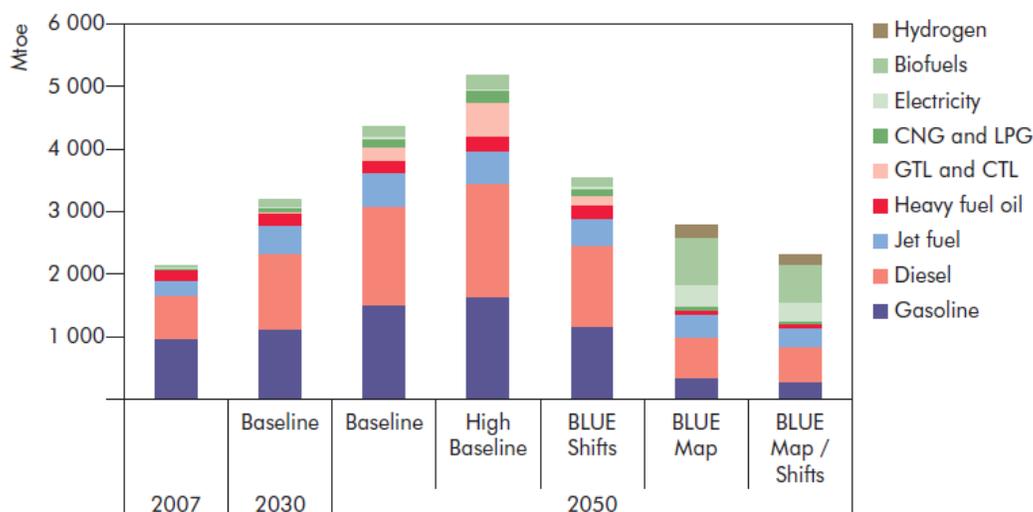


Figure 3: Evolution of transport energy use by fuel type, worldwide. Source: IEA, 2010

2.2 Refining Industry interest in CCS

Projections of deployment, statements by various companies and demonstration projects currently underway indicate a desire in the refining sector to understand the potential for and implications of deploying CCS as a substantial CO₂ abatement option. In order to prove CCS technology and to monitor the G8 goal of achieving commercial deployment of 20 CCS projects by 2020, the Global CCS Institute has developed an ideal portfolio of projects: it believes there should be 26 projects in order to prove various configurations of technology in various industrial sectors, transport configurations and storage options (LEK, 2009). The major contributors to CO₂ emissions are power generation, iron and steel and cement. Outside these three, refineries are identified as a target, because high purity CO₂ is produced as a byproduct of certain hydrogen production configurations. The



Global CCS Institute portfolio recommends that at least 3 of the 26 projects be in processes which already produce high purity CO₂, such as applicable refinery hydrogen production processes (LEK, 2009). This interest in demonstrating CCS on certain hydrogen production facilities is a reflection of the relatively low amount of processing required before storage and hence low costs, which it should be noted is not a generalisation on the totality of a refinery, as discussed in more detail in section 5.2. In terms of geographic location of the projects, the LEK report recommends 60% are located in the Europe, North America and China regions, 15% in Japan and Australia, and final 25% should include India, Russia, Rest of Asia, Latin America, the Middle East and Middle and East Africa. There is no preference for the type of project in each region.

The IEA Technology roadmap for CCS (2009b) predicts that in order to meet climate change goals, 100 CCS plants need to be deployed by 2020 and 3,400 by 2050. In this roadmap the IEA does not specifically point to CCS in the refining industry as a target for deployment of CCS out to 2050, but does include hydrogen production as one of the target sectors. The IEA predictions are based on the BLUE map scenario, which predicts a decline in the demand for liquid fuels. For this reason it is hard to determine exactly how many CCS plants are expected to be deployed in the refining sector and if this should even be a focus for development.

Oil companies and by implication refineries, are increasingly emphasising their “green credentials”, as can be witnessed by their increasing interest in alternative energy and in cleaner production methods. BP (through its “Alternative Energy” unit), Shell, Chevron and Statoil have all entered the market for renewable energy (including wind and biofuels) during the past decade (although BP and Shell have since re-balanced their positions). The current environmental crisis in the Gulf of Mexico is likely to influence developments as well, although it is too early to say how or when. This increased interest in sustainability (whether perceived or real) may result in an appetite for technologies such as CCS, including the application of CCS to refineries. Furthermore, CCS at refineries can potentially be a (although limited) Low Carbon Fuel Standard compliance option, depending on regulatory acceptance.

OPEC recently stated that it “advocates further development of CCS technologies and where possible, in conjunction with CO₂-enhanced oil recovery” (OPEC, 2010).

Note that there are differences between the motivations of national oil companies and international oil companies to implement greenhouse gas technologies, including CCS. Because of the level of development in most of the countries of national oil companies/refineries, the priorities for these regions (and their industry) are to reduce poverty and increase standards of living. It will be more difficult to justify implementing CCS which will increase demand for already over stretched electricity or water supplies to the detriment of the general population.

In the developed world, there are some projects looking at implementing CCS in refineries. One such project is the Rotterdam Climate Initiative (RCI) which is investigating the potential for developing a CCS network for the Rotterdam industrial complex, reducing emissions in 2025 by 50% compared to 1990. The RCI plans to use CO₂ in the horticulture industry, expanding the existing CO₂ pipelines from the Shell refinery, and to use, in a start up phase, ships to transport the CO₂ for storage. In this project, pure sources of CO₂, such as those from refinery hydrogen manufacture, are to be addressed in the first phase (Rotterdam Climate Initiative, 2009).

Another European project that indicates interest in development of CCS technologies from the refining industry is the European CO₂ Technology Centre Mongstad (TCM), next to the Mongstad refinery in Norway. The project is currently building two small-scale capture demonstration plants. Also there are plans to develop a full-scale capture plant on the natural gas fired combined heat and



power (CHP) plant. The demonstration project will capture CO₂ from both a power station and refining flue gases with different compositions. The project is part owned by A/S Norske Shell, Statoil ASA and South African coal to liquids refining company SASOL, who purchased a 2.44% share in 2010 (TCM, 2010).

In North America, the US Department of Energy used the 2009 economic recovery package to fund a number of CCS projects, including three refinery-based projects; the IGCC plant at the ConocoPhillips refinery in Houston, the hydrogen production gasifier at the BP refinery in Denbury, Connecticut, and the steam methane reformer project in Port Arthur, Texas. Subsequently, the Air Products & Chemicals and Denbury Onshore-led Port Arthur project was selected in June 2010 for further funding of the order of \$US 253 million, to proceed with the project. It is important to note that all these projects are government-funded in one way or another. In Canada, the Alberta Government has recently agreed to fund the North West Upgrading Bitumen Refinery, near Edmonton, as part of its Bitumen Royalty in Kind initiative. The refinery is to be built with CCS capability. These already announced projects indicate that there is some appetite mainly from the public sector, and to a lesser extent the private sector to develop CCS for the refining industry. In the perspective of the requirements to combat climate change, many more projects will be required. Technical aspects of these projects are described in more detail in Section 4 Technical Overview of Capture Options.

3 CURRENT AND PROJECTED EMISSIONS

3.1 Historic Emissions and Uncertainty

Historic data of greenhouse gas emissions has been estimated by a number of sources, but this study has found no comprehensive record for the world's refining industry. The most freely available source of data of existing CO₂ for the worldwide refining industry is the IEA Greenhouse Gas Program (IEAGHG) CO₂ Emissions Database. The information in this database is based on numerous editions of the Oil and Gas Journal's worldwide refining survey, the most recent being the 2008 edition of the survey. Most of the emissions in the database are estimated, other than those in Europe, which are measured for the EU Emissions Trading Scheme (ETS). IEA-GHG (2008) reports that refineries produce 818 Mt CO₂/year. The IPCC (2005) report that refineries make up 5.97% of global emissions, based on an earlier version of IEA-GHG's CO₂ emissions database.

Estimates of the emissions are based on the daily production capacity operating for 8,300 hrs/year with an emissions factor of 0.219 kg CO₂/kg of product (IEAGHG, 2008). The assumptions made in these estimates lead to uncertainty in the final estimates, and a number of different sources would suggest that the uncertainty is great. Gary and Handwerk (2001) state that typically for a 300,000 bbl/d refinery, CO₂ emissions range from 0.8 million tCO₂/y to 4.2 million tCO₂/y, which correlates to an average of 2.28 million tCO₂/y with uncertainty of ±1.55 million tCO₂/y or ±70%. Typically a refinery will use between 4% and 15% of the crude oil input for process energy production (Szklo & Schaeffer, 2010) depending on the configuration. The European BREF document (EIPPCB, 2003) for mineral oil and gas refining suggests uncertainty in the specific emissions from refineries is even greater, stating that refining-specific emissions vary from 0.02 kgCO₂/kg of product to 0.81 kgCO₂/kg of product. Others support the figure of 0.219: Mertens (2009) published the EU average as 0.22 t CO₂/t crude. Additionally, Table 4 shows that the specific emissions are dependent on the refinery configuration.

Table 4: Refinery configuration CO₂ Emissions. Source: Mertens (2009)

Refinery Configuration	t CO ₂ /t crude
Hydroskimming	0.08 - 0.15
Fluidised Catalytic Cracker + Vis Breaker	~0.2
Hydrocracker Unit + coker	0.2 - 0.35
Residual Desulphurisation + Residual Fluidised Catalytic Cracker	0.3 - 0.4

The IEA-GHG CO₂ emissions database uses a figure of 8,300 hours of full load operation for calculating the emissions, suggesting 95% of the time refineries operate at full load. Using figures for refining capacity and refining throughput (BP, 2010), would suggest that using full load operational time of 8,300 hrs/y is optimistic, given that it does not address part load operation. BP figures show that the world's refinery throughput between 2000 and 2009 was about 84% of capacity. Given that the IEA-GHG (2009) uses full load hours to calculate the emissions, a figure of 7,400 hours (11%) would appear to be more realistic to show emissions of actual refinery throughput. This uncertainty could rise again if utilization rates drop to 76.6% in 2015 as predicted by OPEC (2009). It is beyond the scope of this assessment to calculate what the uncertainty in the existing refining emissions data might be, however, it is a recommendation for further work to form a more accurate inventory.

3.2 Projected Emissions

Projecting CO₂ emissions from refining industry out to 2050 is a difficult task, given that the existing inventory is so uncertain and the uncertain adaptation responses affecting refinery configuration. Concawe (2008) predict that for the European basis, refinery CO₂ emissions share of total CO₂ emissions will increase from 6.1% in 2000 to 8.3% in 2020 and stepwise increase to 10.3% with predicted fuel quality specification changes. ICF (2005) reports that to keep pace with the rise in oil demand, refining capacity needs to have a 9% surplus over oil demand. Based on this assumption and the projections of both the IEA and OPEC, refining capacities for both scenarios are shown in Table 5. Based on both of these assumptions it is fair to assume that the emissions from the refining industry will increase. McKinsey (2005) reports that downstream refining emissions accounted for 1.1 Gt/y of CO₂ in 2005 and project that this will grow to 1.5 Gt/y by 2030. LEK (2009) have predicted that by 2020, the refining sector will contribute 1.3 Gt/y CO₂ emissions. Looking further out is much more uncertain, due to the differences in predictions for the demand of liquid fuels, and the use of non-conventional fuels.

In its business-as-usual scenario, the IEA (2010) predicts that industrial emissions in 2050 will rise to between 19.9 Gt CO₂ and 21.9 Gt CO₂ and conventional liquid fuels for transport could increase by as much as 40 Mbb/d. Abatement described in the so-called BLUE map scenario aims to maintain long term global temperature rises within 2°C to 3°C range. In the BLUE map world crude oil demand is expected to fall by 27% compared with 2007, although the exact implication for the refining sector is not defined. Demand for Gasoline, Diesel, Jet fuel and Heavy fuel oil, all fall considerably under this scenario, which will heavily influence the refining industry throughput (see Figure 4). Under the BLUE map scenario, world industrial emissions are predicted to be between 11.0 Gt CO₂ and 12.5 Gt CO₂.



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Table 5: World oil consumption and refining capacity related for the OPEC and IEA projections in Mbbbl/d. Oil consumption projections are from IEA (2008c) and OPEC (2009).

Year	1990	2006	2008	2010	2015	2020	2025	2030
OPEC 2009 World Oil Consumption			85600	84600	90200	95400	100400	105600
World Refining Capacity (OPEC)					98318	103986	109436	115104
IEA 2008 Oil Consumption	68222	86624			98193	102945	107155	110865
World Refining Capacity (IEA)					107030	112210	116799	120843

Under the BLUE map scenario for transport fuels, outlined “well to wheel” analysis in Figure 3, the world refining industry would be expected to decline and hence the potential for CCS in the refining sector is in retrofit. Figure 4 indicates that there will be some regional emissions growth to 2050. Transport related emissions including refining in China, India and rest of world including Middle East, Africa and Latin America could grow for various scenarios, hence there is potential for greenfield CCS deployment in these regions. Based on Figure 4, the potential for CCS deployment in the more establish OECD markets to 2050 may be as retrofit of brownfield refinery sites.

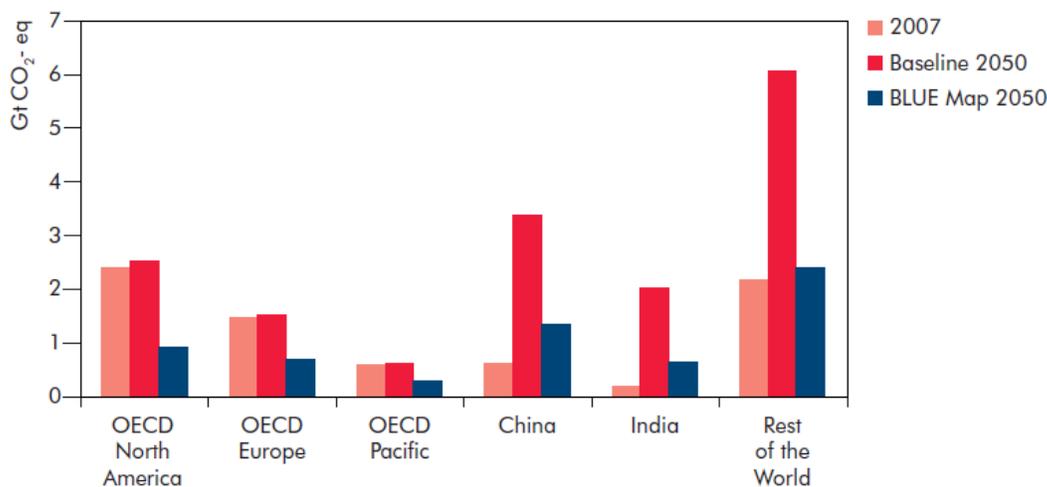


Figure 4. Well-to-wheel transport CO₂-equivalent emissions by region and by scenario. CCS is only relevant to the refinery part of the emissions. Source: IEA, 2010



4 TECHNICAL OVERVIEW OF CAPTURE TECHNOLOGY

The focus of this chapter is on the capture of CO₂, as the transport and storage of CO₂ are more generic and relate to all applications of CCS. There are three different pathways for capturing CO₂; post-combustion capture, pre-combustion capture and oxy-fuel combustion capture and in this section we explore the potential of each for the refining industry. Post-combustion capture is the removal of CO₂ from flue gases of a combustion process, most likely using a chemical absorption process, following the combustion of the carbonaceous fuel. Pre-combustion capture involves the partial oxidation of a carbonaceous fuel, followed by steam reforming to produce high concentration hydrogen and CO₂, which are subsequently separated. Hydrogen can then be used as a clean burning fuel. Oxy-fuel combustion involves combustion of carbonaceous fuel in high purity oxygen, forming a flue gas of only steam and CO₂, which are separated by condensing the water. A summary of the CO₂ separation technology used to actually separate the CO₂ is shown in Table 6.

Refineries consist of a number of complex and varied unit processes and hence have numerous point source emissions distributed over a large site. For the sake of this study and to simplify the refinery scenario, the emissions streams will be classified in the following four categories: process heaters, utilities, fluid catalytic cracker (FCC) and hydrogen manufacture. Table 6 offers more detailed description of each category outlined, the proportion of the typical refinery emissions it makes up and the concentration of the CO₂ emitted. There will also be a distinction between the likely capture options for new refineries vs. retrofitting existing refineries. In the interim between the initial demonstration of capture technology and any eventual mandatory requirement to CCS there may be a need for plants to be built “capture ready”, which is something that will need to be explored in more detail.

Table 6: An overview of major CO₂ emission sources at a typical refinery complex. Source: van Straelen et al., 2009.

CO ₂ emitter	Description	% of total refinery emissions	Concentration of CO ₂ stream
Process Heaters	Heat required for the separation of liquid feed and to provide heat of reaction to refinery processes such as reforming and cracking	30-60 %	8-10%
Utilities	CO ₂ from the production of electricity and steam at a refinery.	20-50%	4% (CHP Gas turbine)
Fluid catalytic cracker	Process used to upgrade a low hydrogen feed to more valuable products	20-50%	10-20%
Hydrogen manufacturing	For numerous processes, refineries require hydrogen. Most refineries produce this hydrogen on site. The requirements for Hydrogen increase with demands of stricter fuel quality regulation.	5-20%	20- 99%

4.1 Process Heaters

Combustion in process heaters account for up to 60% of a refinery's CO₂ emissions. Currently the two most developed technologies likely to be used for emissions reduction from process heaters (and utility boilers) in the refinery scenario are post-combustion capture and oxy-fuel combustion. Technologies that potentially could feature in the future include chemical looping combustion for green field using refinery gas (Morin and Béal, 2005) and pre-combustion capture, using hydrogen fuel in boilers and heaters (IEAGHG, 2000). Further studies are required to assess the potential of pre-combustion for refinery process heaters, since this will include hydrogen production units (Mirracca, 2009).

Post-combustion capture has been investigated for a number of scenarios, namely Hurst and Walker, (2005) and van Straelen et. al. (2010). The engineering details for capture will vary, but the basis for the Hurst and Walker (2005) study was the 196,000 bbl/d, Grangemouth refinery in Scotland and capture of the CO₂ emissions from the fired heaters and boilers on the site. They proposed to collect all the stacks gases from these heaters across the site and duct them to a central location where CO₂ is separated and compressed. To move these gases across the site would require the addition of fans to move the stack gases to the central treatment process. This is not a unanimously accepted configuration as van Straelen et. al. (2010) question the feasibility of such a configuration on a larger 400,000 bbl/d refinery, stating that finding the space for large diameter ducting will be a challenge, and instead propose only capturing the CO₂, from the largest stack emissions. This lack of agreement indicates that solutions will be site specific and further detailed design is required to establish the best for each. Independent of the ducting configuration is the requirement to remove the NO_x and SO_x from the stack gases before the CO₂ absorber to reduce degradation of the absorption solvent. With the lay outs of refineries with numerous emission points of different sizes, the capture rate at refineries will be limited and be determined by the "tail" of smaller hard to connect emissions points rather than the capture efficiency of the capture technology/process.

Removal of NO_x and SO_x from flue gas streams is a relatively well known technology, which is applied to combustion processes in a number of industries for environmental reasons. Metz et. al. (2005) state that SO_x needs to be reduced to between 1 & 50 ppm for post-combustion capture of CO₂ in flue gases. For combustion of refinery or natural gas in heaters and boilers, SO_x removal may not be required, but where higher sulphur fuel oil and solid fuels are used this will be required. Concentrations of NO_x needs to be reduced to 20 ppm for CO₂ capture (Hurst & Walker, 2005), meaning that some form of NO_x reduction will almost certainly be required on all heaters and boilers irrespective of the fuel. To operate the SO_x and NO_x reduction technologies there are also requirements for soot and fly ash in order to prevent plugging of the absorbers (Metz et. al., 2005). The addition of CO₂ capture will require considerable amounts of additional energy and utilities and result in an increase in (to be captured) emissions. Table 7 details the utility requirements and waste production of equipment required to retrofit Grangemouth refinery with CCS on the process heaters and boilers. The basis for this is using Fluor Econamine FG+ process for CO₂ capture, Cansolv process for SO_x capture and selective catalytic reduction (SCR) for NO_x treatment.

Oxy-fuel offers another potential mechanism for capturing the CO₂ from heaters and boilers. The Grangemouth refinery was used as the basis for investigating the deployment of Oxy-fuel for an existing refinery (Wilkinson et. al., 2003 & Allam, 2005). For this scenario it is proposed that all heaters and boiler on site are modified for firing with pure oxygen, produced at a central location, and that flue gases from the combustion plants will be initially treated at locations local to the stacks (where water will be removed and CO₂ will be compressed to 30bar). As shown in Table 8 the production of the oxygen will require considerable amounts of additional (electrical) energy and thus



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increase CO₂ emissions. Final compression of CO₂ to pipeline pressure will take place at one central location. To fire the process heaters and boiler that produce 2 million tonnes/year of CO₂ with oxygen, two 3,700 tonne/day air separation units (ASU) will be required (Allam et. al., 2005). By current standards, these are very large given the largest existing facility is 3,500 tonne/day (Metz et. al., 2005). All of the heaters and boilers will require significant modification or replacement. The use of induced draft fans on the flue gases means in order to reduce the amount of air leakage into the boiler better sealing is required, but complete sealing is not feasible due to maintenance requirements (Wilkinson et. al., 2003). To control the combustion temperature, each heater and boiler will also require modification for flue gas recycle, including the addition of a flue gas recycle fan. The ability to completely shut off of boiler flue gases is required in addition to use of air for firing during start up. The result of these modifications will reduce the firing rates by up to 15%. Typical for any refinery, one of the challenges will be the large distances for piping oxygen and carbon dioxide across the site between oxygen facilities and CO₂ compression stations, illustrated in Figure 5 which gives an isometric of a proposed layout of the Grangemouth refinery.

Table 7: Shows the increases in utility requirements and wastes produced when retrofitting post combustion capture and compression to the heaters and boilers of the 196,000 bbl/d Grangemouth refinery. Process changes will reduce CO₂ emissions by 2 million tonnes/year from refinery boilers and heater. Source: Hurst & Walker, (2005).

Utilities	Quantity
Steam	480 tonnes/h
Power	72 MW
Cooling Water	18,139 m ³ /h
Process Water	1025 tonnes/h
Source and Wastes	
CHP Stack from additional power & steam (CO ₂ produced at 18% eff from natural gas)	0.6 million tonnes/y
Cooling towers (water vapour)	8 million tonnes/y
Amine Reclaimer wastes (heat stable salts)	150 tonnes/week
SO _x unit (SO ₂ waste)	100 tonnes/week

The existence of new or increased quantities of hazardous materials; pure oxygen and high-pressured carbon dioxide, will increase the level of risk in a refinery, but the existing health safety and environmental hazards on a refining site are such, that these will not require a step change to be managed (Wilkinson et. al., 2003). For oxy-fuel combustion, there may be a technical requirement to remove the NO_x and SO_x from the CO₂ for transport and storage specifications. Allam et. al. (2005), considered three different cases for oxy-fuel capture at the Grangemouth site. Table 8 shows the utility requirements and waste outputs for the case with the greatest capacity to avoid CO₂ from the addition of oxy-fuel CCS technology to the process heaters and boilers. The basis for this is addition of a gas turbine operating pre-combustion CO₂ capture to generate power for the ASU compressors and additional fans, two 3,700 tonne/d adiabatic ASU's, configured as described above.



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Based on promising economics, several vendors are developing and commercialising oxy-burners (Miracca, 2009). There are a number of shortcomings that remain, including the heat flux which could induce fouling in some heaters, but it is generally expected that these can be overcome. Further cost reductions can be expected if internal rather than external dilution technology is developed. There is also specific attention to lower the cost of oxygen production. The focus on post combustion technology in the power industry now means that a single amine train is capable of capturing more CO₂ than produced with oxy-combustion from a single ASU, which may be a factor in decision making for retrofit where space is an issue.

Table 8: Utility requirements and wastes produced for the addition of Oxy-fuel CCS technology to the process heaters and boilers with hydrogen fired GT power generation at the 196,000 bbl/d Grangemouth refinery.

Utility	Quantity
Power generated	108 MW
Power Export	0.3 MW
O ₂ requirement	6889 tonne/d
Cooling water use	16,700 tonne/h
CO ₂ Captured	2.33 million tonne/y
CO ₂ Avoided	1.97 million tonne/y

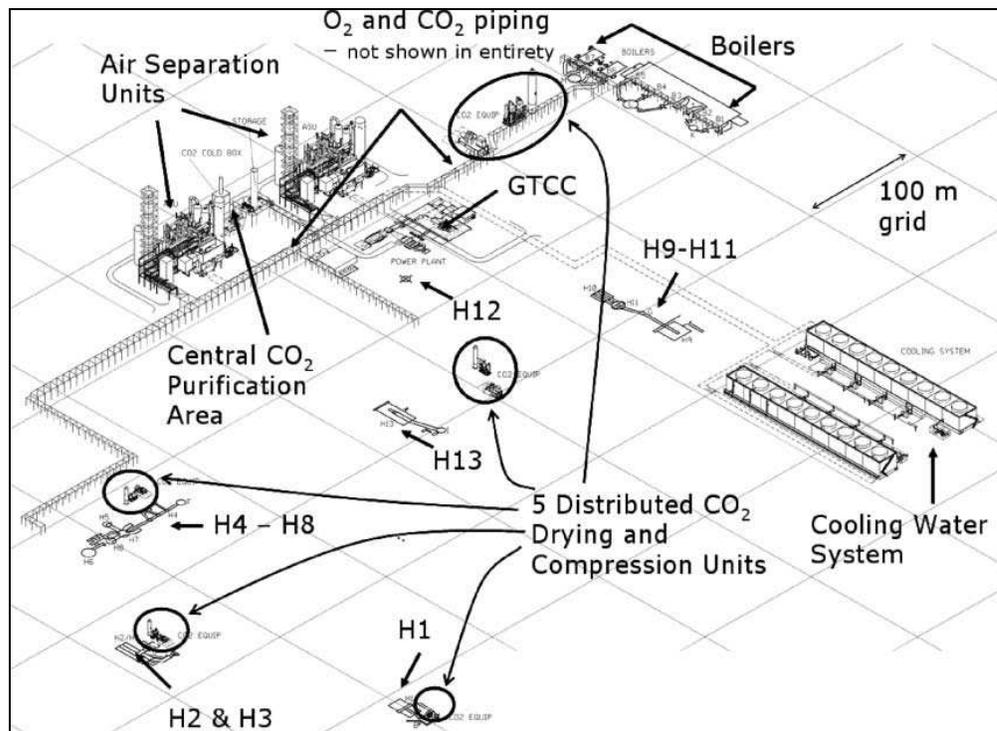


Figure 5: Isometric view of Grangemouth refinery site layout and proposed location of oxy-fuel systems, air separation units and cooling towers. Source: Allam et. al. (2005).

4.2 Utilities

In a refinery, utilities steam and electricity are used by many of the unit processes to varying degrees. There is a much greater demand for steam than there is for electricity for all refinery configurations. Steam is produced in (waste heat) boilers where (GT) cogeneration of Power and Heat is an established energy efficiency (and carbon abatement) measure for refineries, combined with power transport for the optimal power to heat generation ratio. In the near to mid-term, the capture technology most likely to be deployed for utilities is post combustion technology for retrofit that has been developed in other sectors, such as power generation. Longer term, other technologies such as poly-generation and oxy-fuel may offer more potential for new builds. Capture technology for the power generation sector will probably lead the development before other sectors, so refinery utilities are a good opportunity for deployment of their learnings and optimisation. Amine technology developed from acid gas processing is the most advanced and well known technology, however other technology such as the chilled ammonia process (CAP) offer potential as well. Although unproven at commercial scale, process modelling indicates that the CAP process potentially has a smaller energy penalty. Table 9 shows a comparison of the energy penalty for each process, based on a 460 MW_{el} pulverised coal super critical power plant. In order to reduce the need to capture CO₂, the amount of CO₂ emissions should be minimised. Combined heat and power is a technology that has potential for this.

Combined Heat and Power (CHP) or Cogeneration is another technology that offers potential emission reductions due to the increase in overall efficiency. CHP also makes CCS technology more



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applicable by centralising the emissions. Even when operating in a high heat to power ratio, a CHP system will produce excess electricity. The operating nature of a refinery means that steam supply with an extremely high reliability/availability is required, meaning that refinery cogeneration is often a “must run” where the operator can not match the load to the spot prices and hence increases risk for scenarios where electricity is sold on the open market, without external incentives. Therefore the operation of a CHP plant at a refinery is complex and requires several operating modes in order to be effective. There are numerous examples of the deployment of CHP in the refining industry for efficiency purposes: In the UK, the Immingham 734 MW_{el} natural gas fired CHP plant has been successfully operating since the 2004 and produces heat and power for two UK refineries, while Pergen in the Netherland supplies heat to the Shell Pernis refinery, etc. In Australia, the Queensland Clean Fuels Project at the BP Bulwer Refinery is an example of CHP and also integrated use of gases of commercial gases, as shown in Figure 6. This complex gives the refinery many advantages including the ability to supply and receive utilities from the cogeneration plant. This is a good example of centralising industry for efficiency gains, which also centralise CO₂ emissions for easier capture.

Table 9. Comparison of energy efficiency of two capture technologies on a 460 MWe pulverised coal fired super critical power plant. Source: Rhudy, 2006

	Supercritical without CO ₂ capture	PC Supercritical PC with MEA CO ₂ capture	Supercritical PC with CAP CO ₂ removal
Auxiliary Power, MWe	29.1	72.7	56.1
LP Steam extraction, kg/hr	0	551,405	204,684
Net Power Output, MWe	462.1	329.5	415.3
Net Efficiency, % HHV	40.5	28.9	36.4
CO ₂ emissions, kg/kWh	0.78	0.11	0.09

The Norwegian Mongstad refinery CHP project has been high profile because it is potentially one of the first gas based power plants to have CCS fitted to it. Currently under construction is a 280 MW_{el} natural gas fired CHP power plant that is capable of producing up to 350 MW_{th} of steam. In parallel to the CHP plant, a test facility is being built where two different post combustion capture technologies will be tested side by side (Statoil, 2010). The capture technologies to be tested at European CO₂ technology centre Mongstad (TCM) refinery are Aker Clean Carbon’s amine based process and Alstom’s chilled ammonia process, beginning operation in 2011 capturing 100,000 t/y between them (TCM DA, 2009). CO₂ from two slip streams of the natural gas fired CHP plant and a slip stream from the adjacent Mongstad refinery FCC process emissions will be used to test the two post combustion technologies. Initially the plant will operate at about 60% overall efficiency, but as more of the refinery is integrated into the project this will increase up to 80% overall efficiency. Electricity produced by the power plant will be used in the refinery and exported to the Troll A offshore platform. The new CHP plant will increase the refinery emissions by 0.95 Mt/y, but will reduce the need for energy import to the refinery and offshore platform, thereby decreasing global emissions (Statoil, 2010). The outcomes of the post-combustion capture technology comparison in the test centre will be used for the scope and the optimisation of the retrofit of the CHP plant with CO₂ capture technology. The Norwegian government, who are funding the capture part of the project, initially wanted to make an investment decision on the capture technology to be deployed at Mongstad in 2012, but have revised this to 2014 (The Royal Norwegian Ministry of Petroleum and Energy, 2010).

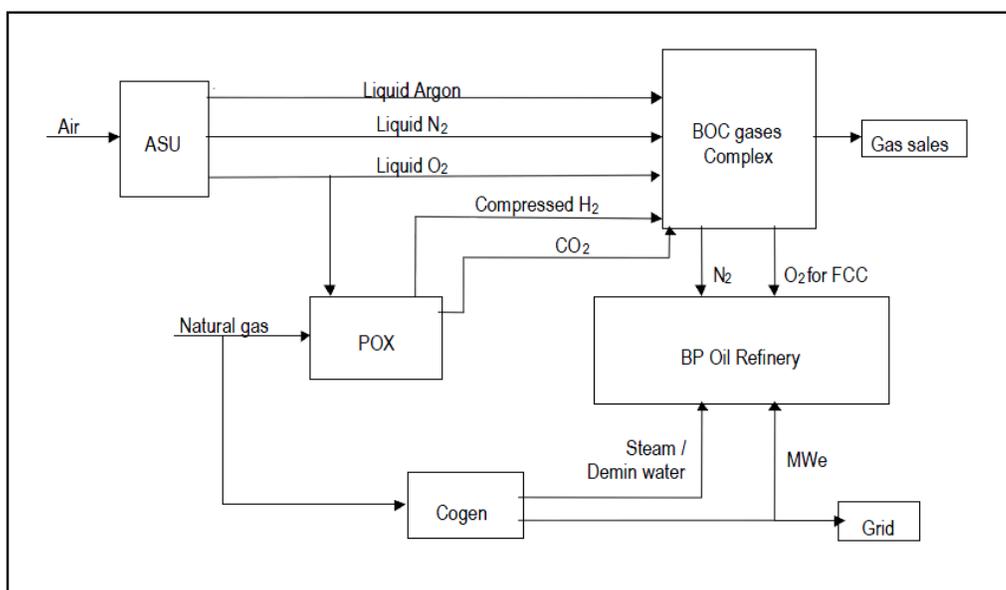


Figure 6: Bulwer Refinery complex, with air separation unit, natural gas partial oxidation, and cogeneration plant feeding a refinery and industrial gases plant. Source: Phillips, 2002.

Integrated Gasification Combined Cycle (IGCC) is a pre-combustion process for utilities supply at a refinery that can be coupled with CCS. An attraction of IGCC is the capability of the gasification unit to be used to produce hydrogen and/or synthesis gas which could be used in a poly-generation scenario. In the poly-generation gasification of heavy residues configuration, co-production of hydrogen can be combined with synthesis-gas used in gas turbines for cogeneration of steam, potentially retrofitted to full shift and hydrogen use in developing gas turbine technology, which centralises the source of CO₂ emissions. As stated earlier, there is a need for further work to evaluate if this is a feasible solution, although project examples exist, such as the OPTI Canada Oil Sands project (Simbeck, 2005). The complex nature of this solution makes it more suited to new builds, where process design can be integrated much more effectively.

4.3 Fluid Catalytic Cracker

Not all refineries operate fluidised catalytic cracking units, but in a few cases they can account for as much as 50% of refinery CO₂ emissions (Kuuskraa, 2009). Unlike most of the other emissions from a refinery, the emissions from the fluid catalytic cracker (FCC) are process related rather than combustion related. During processing, carbon is deposited on the surface of catalyst powder, essential to the process deactivating the catalyst. The catalyst is regenerated by oxidation of the coke with air. Depending on the exact process, the concentration of CO₂ in the flue gas typically ranges from 10% to 20% (de Mello et. al. 2008). Two options exist for the capture of CO₂ from the FCC, one is the more mature post-combustion capture, the other still in development is oxy-firing of the regeneration process. De Mello et al. compared the potential for both regeneration processes and their relative merits and reported that despite the relatively high capital cost of oxy-firing, the potential of lower operating costs make it attractive proposition in a carbon constrained world. A field



demonstration on a Petrobras 60 bbl/d FCC in Brazil is currently underway (Kuuskraa, 2009). Small-scale testing shows that it is technically feasible to maintain stable operation of an FCC in oxy-firing mode (de Mello et al., 2008). Table 10 shows the relative utility consumption and waste generation of post combustion CO₂ from an FCC compared with oxy-firing of the FCC. The basis for the study is a 10,000 m³/d residual FCC, using Kerr-McGee CO₂ recovery system with an MEA (Monoethanolamine) solvent for post combustion capture, and a SO_x scrubber to reduce concentration to 7ppm. The oxy-firing cases are based on using an air separation unit to produce either 99.9% vol. O₂ or 95% vol. O₂. SO_x in the hot flue gases are removed with a SO_x scrubber prior to dehydration and compression.

Table 10: Relative utility usage and waste production for post combustion capture of CO₂ from an FCC compared with oxy-firing of the FCC. Source: de Mello et. al. (2008)

Utility	Post-Combustion Capture	Oxy-firing, 99.9% O ₂	Oxy-firing, 95% O ₂
Water make-up	67.5 m ³ /h	59.8 m ³ /h	59.8 m ³ /h
Water blow-out	15.1 m ³ /h	18.3 m ³ /h	18.3 m ³ /h
Cooling water consumption	572.2 m ³ /d	288.3 m ³ /d	314.1 m ³ /d
HP Steam consumed	140.3 t/h	0.3 t/h	0.4 t/h
MP steam consumed	0	2.3 t/h	2.4 t/h
LP steam consumed	216.5 t/h	0	0
HP steam produced	78.7 t/h	103.6 t/h	102.2 t/h
Electricity consumed	15.8 MW	74.0 MW	71.2 MW

4.4 Hydrogen Production

Hydrogen is an ever increasing contributor to the CO₂ emission profile of a modern refinery as changes to fuel specifications require increased levels of hydro-treating. Hydrogen production is also important in the production of fertiliser, chemicals and as an energy source going forward. These industries are covered in more detail by the pure sources of CO₂ assessment report.

On a refinery, between 5% and 20% of CO₂ emissions are linked to the production of hydrogen (H₂). Hydrogen is a by-product of the catalytic reformer and FCC processes; however, as demand has increased with changes in fuel specification, demand now exceeds supply from these processes in most refineries. To meet the increased demand, hydrogen is produced either through steam methane reforming of natural gas or gasification of heavy residues and fuel oil. Hydrogen produced in both of these processes needs to be separated from other constituents in the flue gases.

Gasification plants for hydrogen manufacture are generally larger than SMR and operate at high pressures of 50-70bar. These conditions are suitable for the use of physical absorption solvents over chemical absorption solvents because they have higher loadings, require less energy input and produce dry CO₂ under these conditions. With gasification, all the CO₂ emissions associated with conversion end up in the flue gas stream and hence there is a higher rate of capture than SMR.

Traditionally, hydrogen produced in SMR was purified using chemical absorption systems such as hot potassium carbonate or MDEA (Methyldiethanolamine), however, there is a more recent trend in the past three decades, towards separation using pressure swing absorption. In SMR systems with chemical absorption, about 60% of the total CO₂ emissions are captured in high purity stream, 99% CO₂, and the remainder ends up in a nitrogen rich flue gas stream from the furnace. In the current refining market pressure swing absorption (PSA) offers two advantages over amine chemical absorption: 1) PSA produces very high purity hydrogen, 99.9+% and 2) the overall energy efficiency of the hydrogen production process is increased compared with chemical absorption (Lindsay et. al., 2009). The change to PSA has been driven by a market for high purity hydrogen and has led to much lower concentration CO₂ streams containing 20-30% impurities, depending on the feed and design. The impurities include H₂, CO and CH₄ which means the gas is effective as part of the fuel for the SMR furnace further diluting the CO₂ in the final combustion product and reducing the CO₂ capture feasibility (Simbeck, 2005). The use of PSA means that further separation and processing are required to prepare CO₂ for transport and storage, leading to higher capture costs. Hydro-cracking has a minimum requirement for hydrogen purity of 95% (Lindsay et. al., 2009), which can be achieved with chemical absorption processes such as MDEA. Although PSA produces hydrogen of higher quality and lower cost in the current economic situation, this may not be the case in a carbon constrained world. The economics are discussed further in section 5.2. The pure or higher concentration CO₂ streams such as hydrogen production using gasification and SMR with chemical absorption may be attractive unit processes for future CCS deployment in a refinery.

The high purity of CO₂ from certain hydrogen production unit operations has made it of interest to publicly funded CCS demonstration programmes. Capturing CO₂ from pure sources such as hydrogen production is the most cost effective for the Rotterdam industrial scenario (Rotterdam Climate Initiative, 2009). The Alberta government has announced plans to fund a 150,000 bbl/d bitumen refinery north west of Edmonton which will incorporate CCS. North West Upgrading will use coke gasification processes to produce hydrogen and CO₂, using hydro-processing on the site to produce high specification fuels. Enhanced Energy is likely to take 3,500 t/d of CO₂ from the plant as part of the project.

4.5 Carbon abatement options other than CCS for the refining sector

The first and most obvious step before investigating the application of CCS to a refinery, is to look at opportunities to reduce existing refinery CO₂ emissions, and hence the amount that may need to be captured. In this section opportunities to reduce CO₂ without CCS are identified. Methods for increasing the efficiency and hence reducing the CO₂ emissions for heaters and boilers include process integration, optimising excess air and using air pre-heaters (Baar et. al., 2009). Opportunities also exist to reduce the heat demand in the refinery by heat integration of processes, in particular the use of combined heat and power generation, offers a good opportunity to reduce the heat and boiler loads, which account for up to 60% of a refinery's emissions. Szklo et al. (2006) predicts potential energy and hence emissions savings with use of heat integration and waste heat recovery, fouling mitigation and advanced process control in existing refineries. For new refineries, replacement of conventional atmospheric and vacuum distillation units with new technologies, use of variable speed drives for motors, membrane separation technology for hydrogen and the use of vacuum pumps and surface condensers offer potential for additional energy and hence emissions reductions. In some situations, where fuels are available, switching from high CO₂ emissions fuels such as coke to lower emissions fuels (See Table 11), can offer some short-term gains, however, unless another use is found for the higher emissions fuels, then fuel switching will not reduce global emissions. Fuelling heaters,



MANAGING RISK

utilities and hydrogen production processes with biomass also has potential to reduce the carbon footprint of the refining sector. Hydrogen is often a constituent of refinery gas, which is combusted in heaters and boilers as a low CO₂ fuel, however, the emissions created in producing the hydrogen are greater than those saved by burning it as a fuel. From a CO₂ point of view it is therefore beneficial to reuse hydrogen by products as much as possible rather than make more hydrogen (Clark, 2000).

Table 11: Carbon Dioxide emissions of refinery fuels, (abbreviations: C-Carbon, H-Hydrogen, P-Parafins, O-Olefins, A-Aromatics). Source: EIPPCB (2003)

Fuel Type	Typical Composition (%w/w)	kgCO ₂ /kg fuel	kgCO ₂ /GJ
Refinery fuel gas	30H ₂ , 35C ₁ , 35C ₂ % v/v	2.83	43
Natural Gas	100% methane	2.75	56
LPG	50C ₃ , 50C ₄	3.02	64
Distillate Fuel Oil	60P, 10O, 30A	3.22	74
Residual Fuel	50P, 50A	3.26	79
Coke	90C, 10 ash	3.3	117

Research funding specifically for the refining sector generally focuses on topics such as higher yields, energy efficiency and shorter downtimes, rather than on novel processes. In recent times large oil and gas companies have reduced their research and development efforts and are relying more on third parties to undertake development work and supply technology when it is required (EIPPCB, 2003). Developments are reported in the technical literature (Hydrocarbon Processing, Chemical Engineering Progress, Oil and Gas Journal, Erdöl, Gas und Kohle, Petroleum Technology Review) and during seminars and conferences (World Petroleum Congress, WEFA, Hart's Fuel Conference, European Refining Technology Conference, NPRA and API specialist meetings) for the dissemination of those techniques.

Other research efforts for carbon abatement in the oil and gas sector have focused on producing fuels that are cleaner burning, high efficiency, with lower tail pipe emissions. This research is being undertaken at a number of institutes mainly in the developed world, but it is expected that successful technologies will be rolled out around the world, as they have been in the past. Energy and process efficiencies have potential to reduce CO₂ emissions, but for substantial CO₂ emissions reductions (>40%) CCS remains a promising technology.

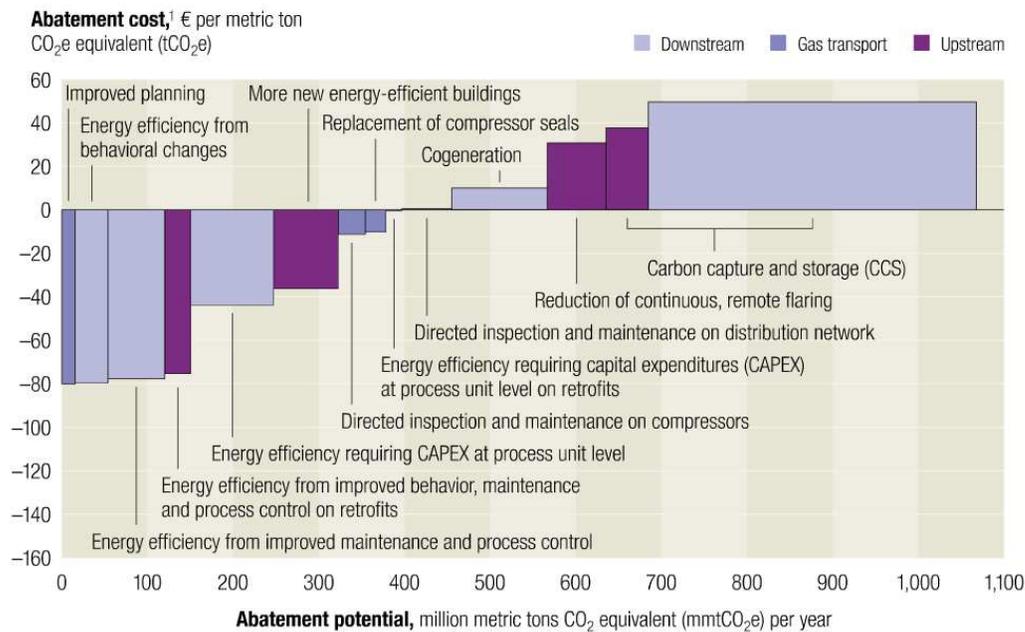


Figure 7: Carbon Abatement cost and potential emissions savings for the oil and gas industry. Source: McKinsey (2010)

McKinsey (2010), suggest that the options for making deep cuts into carbon emissions to 2030 will differ by region. In the developed world, Western Europe, North and Latin America, CCS offers the most potential for large cuts in CO₂ emissions; in Africa it will be reducing flaring; in Eastern Europe and Russia, it will be reducing emissions associated with pipeline networks; and in China, India and developing Asia energy efficiency and co-generation offer the most potential. Figure 7 shows the potential for CO₂ emissions reduction for the world's oil and gas industry as a whole and likely costs/savings, more specifically the downstream savings relate to the refining sector. CCS clearly shows potential to capture the most emissions, but it also has the greatest cost and other emissions reduction options will actually have cost savings. The opportunity areas McKinsey has identified for the downstream refining sector include: Energy efficiency from behavioural changes, from improved maintenance and process, requiring CAPEX for process units; cogeneration; and carbon capture and storage. It is important that all lower cost CO₂ abatement measures are implemented before considering CCS, to reduce the overall cost of CCS and hence increase the chances for economic deployment.

5 ESTIMATED COSTS AND INVESTMENTS

5.1 General CCS costs

McKinsey & Company published a study in 2008 that has become a much-referenced source on the costs of CCS. Although that study focuses on coal-fired power plants, it is informative in terms of producing a range of costs based on a bottom-up review of options. The costs of CCS are defined as “the additional full cost, i.e. including initial investments and ongoing operational expenditures of a CCS power plant compared to the cost of a state-of-the-art non-CCS plant, with the same net electricity output and using the same fuel”. Note that the costs include transport and storage, as well as capture. The cost range is found to be between €30-90/tonne CO₂, which is further subdivided into €30-50/tonne for a commercial scale plant and €60-90/tonne for the initial demonstration projects. Note that the initial CAPEX of the capture unit represents half of the CO₂ capture cost. It follows from this that the greatest cost savings for CCS overall would come from improvements in the cost of capture/capture technology improvements. This is likely to be true for the refineries sector as well. Note furthermore that the cost of storage, while not among the largest components in the CCS value chain, is the component with the highest relative variability due to the range of possible characteristics of storage locations.

Another general cost reference for CCS is the INTEK estimate (Oil&Gas Journal, 2009) that focused on a US coal power plant case study. They find that CO₂ capture costs range between \$34-61/tonne CO₂ and that total costs range between \$43 and \$115. This estimate (translated to Euros: €35-93) is thus in line with the McKinsey&Company estimate. It is also noted that \$/t CO₂ capture costs for refineries will be higher than for coal fired power plant, as a result of complexity (ducting of smaller sources), scale, cost of energy and lack of utility integration (refinery application demands dedicated Capture plant utilities) and other factors. In open Cap &Trade systems this could lead to a prolonged buying of CO₂ credits for refineries as the economic optimum.

5.2 Refinery Specific Costs

Studies of the costs of applying CCS to the refineries industry have been carried out, including those published by CO₂ Capture Project (CCP) (Melien and Brown-Roijen, 2009), van Straelen et. al. (2009) and Tel Tek (2009). Tel Tek estimate that the capture cost for the Esso Slangentangen refinery distillation heater would be €77/tonne CO₂ (NOK 607/tonne CO₂). The CCP (Melien and Brown-Roijen, 2009) reported more detailed capture costs for a natural gas fired power plant, refinery process heaters and boilers, and the FCC. For power generation, a number of both post-combustion and pre-combustion technologies were assessed and used as a basis for calculating a range of carbon dioxide avoidance costs based on a new 400MW_{el} Combined Cycle Gas Turbine in North West Europe. For the refinery heaters and boilers, the post-combustion, pre-combustion and oxy-fuel scenarios have been assessed for both retrofit and new boiler cases in North West Europe. For the FCC both post-combustion and an oxy-fired process have been considered for a Brownfield scenario situated in South America. The scenarios assessed are approximated from real processes either currently available from, or under development by, equipment suppliers, based on prices in June 2008. Table 12 summarises the cost results for capture only from the CCP, along with additional studies that are relevant. It is important to note that a number of the low cost options are for advanced technologies that are yet to be proven in the field and may never eventuate in the industry.



Table 12. Capture costs for various refinery process units, not including transport and storage. Created based on Melien and Brown-Roijen (2009), and Lindsay et. al. (2009).

Process Captured	Capture Type	Retrofit or New Build	Avoided Cost [€/t]
Utilities, Combined Cycle Gas Turbine	Post-combustion	New	28-75
	Pre-combustion	New	27-76
Heaters and Boilers	Post-combustion	Retrofit	77
	Pre-combustion	Retrofit	49
	Oxy-combustion	Retrofit	44
	Post-combustion	New	96
	Oxy-combustion	New	50
	Chemical Looping Combustion	New	33-42
Fluid Catalytic Cracker	Post-combustion	Retrofit	85
	Oxy-fired	Retrofit	55
Hydrogen Production	SMR combustion	Post New	19-53 (\$/€ = 0.75)

There were a number of studies undertaken prior to 2008, such as those highlighted by IPCC (Metz, 2006), which came at the end of a period of rapidly increasing construction costs and prior to the economic downturn of that same year. These have not been included because they are considered less relevant than more recent references. A study by Shell for retrofit of a generic refinery (Straelen et. al., 2010) estimates the full chain cost costs for cumulative emissions, but are not specific about the unit process. In that study, the CO₂ avoided costs are reported to range from €90 to €25/t CO₂ avoided for the flue gas streams requiring separation. The most economic is the high purity CO₂ captured with amine separation from a hydrogen production gasifier, which only requires compression and dehydration before transport and storage, costing ~€30/t CO₂. This value is supported by the Rotterdam climate initiative (2009) that predicts full chain cost for capture of CO₂ in a refinery of €24/t CO₂. The main point of difference between the two studies is that the Shell Study includes generic transport and storage costs. Another point of difference is that CCP assumes all flue gases from small sources can be combined for central separation, whereas Shell considers this will be less plausible because of space restrictions. This assumption means small capture and compression units spread across the site will be required and lead to much higher costs on smaller CO₂ streams. As indicated earlier in this report, the CCS deployment potential for the refinery industry is in majority in retrofits, given the limited growth in new refinery capacity. As the complexity of brownfield projects is higher, costs will be higher than for greenfield developments.

ERM (2009) calculated costs for capture, transport and storage of CO₂ on refinery heaters, boilers and power plant and hydrogen plant. Capture on refinery heaters, boilers and power plant using amine based post combustion process is estimated to cost €114/t CO₂ avoided (published as \$US152/t CO₂ avoided). This is higher than the costs published by CCP, but closer to those published by Shell. ERM estimate hydrogen plant capture of CO₂ based on a steam methane reforming technology will cost €33/t CO₂ avoided (published as \$US43/t CO₂ avoided). These costs are more than the Rotterdam Climate Initiative estimate, but in line with figure's published by Shell.



The costs for the refineries reported by both Shell and CCP, excluding capture from hydrogen production, are higher than the more widely used figures of McKinsey (2008) for coal fired power generation. This is as expected because the streams from refinery flue gases are much smaller than power plants. Note that demonstration phase and first mover projects can expect to have higher costs than more mature projects. Based on McKinsey (2008), long term costs will be about 50% of the demonstration phase projects due to assumed learning rates with increased deployment capacity. Based on the long term estimated costs of the CCP of between €28-€96/t CO₂ avoided depending on the unit operation, demonstration can expect to cost between €56-€192/t CO₂ avoided. Independent of the accuracy of the costs, the high costs associated with CO₂ capture on refinery streams other than hydrogen production, make them less attractive for CCS deployment in the near and medium term, without incentives or subsidies of some kind.

5.3 Financing CCS

Financing of CCS is likely to come from a number of sources, especially initially in a demonstration phase. In Europe, the price of carbon in EU-ETS will cover some of the costs, however, it is a very uncertain price that will depend on a number of political factors. Based on literature review, McKinsey&Company (2008) forecast a price of €30-48/tonne CO₂ in 2015, which, it must be said, is quite optimistic given today's level (~€15/tonne). However, even with such a high carbon price, a large cost gap for demonstration projects is likely for the power sector and even higher for some unit operations in the refining sector. These cost gaps indicate that other sources of finance are required to fast track CCS demonstration programmes.

Other sources of finance might include Government-sponsored R&D programmes that go toward financing the CAPEX. Examples of this for the power-generating industry include the "UK Competition", EU EERP (the European Economic Recovery Programme) and the EU New Entrants Reserve (NER300). In the UK the 4 CCS competition projects are to be in the electricity sector and will be financed through a levy on electricity suppliers. In Europe, future CCS projects funded by the EU NER300 will be financed through free allocation of emission credits under the EU ETS to selected projects. In North America, the Alberta state government in Canada has offered funding from its annual budget to a refinery capture project, as has the US DOE. Finally, if CCS is included under CDM of the Kyoto Protocol, additional funding will be available that is especially targeted at developing countries.

6 LEGISLATIVE PRESSURES ON REFINERY CARBON EMISSIONS

This section will focus on the specific laws relating to the refining industry, and to a lesser extent general emissions reduction legislation such as the Kyoto Protocol. There are specific elements of the emissions regulations that relate to the refining sector, more specifically carbon leakage, for which mechanisms have been proposed to address the issue. Outside of the GHG reduction regulations there are a number of fuel quality regulations which have implications for refinery GHG emissions. Prior to implementing the fuels directive in 2005, the European Commission's Directorate-General for the Environment undertook a costs and benefits analysis of lowering the sulphur content of petrol and diesel. Similar work has been undertaken to investigate the implications of the IMO proposal to reduce marine heavy fuel sulphur levels from 2015. It is expected that similar costs and benefits will be experienced when similar legislation is implemented in developing countries. An exception to this is likely to be differences in the vehicle fleets of the developing countries, which will affect the tailpipe emissions reductions. Legislative pressures that are the main focus of this report are the

Transport fuel quality legislation, IMO MARPOL Protocol marine fuel specification, Kyoto Protocol, and Emissions Trading Schemes.

6.1 Transport Fuel Quality Legislation

Fuel quality legislation takes many different forms around the world, and is put in place to reduce the sulphur and particulate emissions from liquid fuel combustion in automobiles. The levels of regulation is different for different nations, but has the same effect, in increasing the hydrogen demand of the refinery and hence the CO₂ emissions of the refinery. In Europe, the latest set of limits placed on sulphur content of transport fuels was undertaken in order to allow engine combustion to take place at higher temperatures. At higher temperatures the engine operates more efficiently meaning less CO₂ per unit travel, however, this increases NO_x emissions. Catalytic processes are used to reduce NO_x, however, very low sulphur dioxide concentrations (<10ppm) are required to prevent catalysts being poisoned by sulphur.

In the European context it is estimated that the additional refinery emissions due to this legislation will total 5,400 kt CO₂/y in 2020, with the CO₂ emission reductions in the transport fleet likely to total 15,000 kt CO₂/y by the same year (European Commission, 2001). The costs of the legislation were calculated to be a maximum of €0.003 extra for petrol and €0.009 maximum extra for diesel, due to refining process upgrades. The likely consumer savings due to a reduction in consumption will average 2% for petrol users and 3% for diesel users (European Commission, 2001).

Brazil currently has 13 refineries and a total capacity of 1.9M bbl/d or 2.2% of the world's capacity (Kootungal, et. al., 2009). For Brazil there is expected to be a large impact from reducing sulphur content to a single value of 50ppm for all diesel from the current 500ppm for metropolitan diesel and 2000ppm for rural diesel. This change will require existing plants to expand hydro-treating units (HDT), hydro catalytic cracking (HCC) units and hydrogen production capacity. The increase in the energy demand of the Brazilian refining sector resulting will be about 31% (Szklo & Schaeffer, 2006). This increase in energy usage will result in a 5.5 Mt/y increase in CO₂ emissions (converted from 1.5 MtC/y).

The AFRI-4 fuel specifications for fuel in Sub-Saharan Africa require a sulphur mass content of 150ppm for gasoline and 50ppm for diesel. There is potential for the implementation of the AFRI-4 specifications in Sub-Saharan to actually decrease the refining capacity of the region and increase imports from Europe and the Middle East (ICF International, 2009). Implementation of the AFRI-4 specification in developing regions in Sub-Saharan Africa highlights the willingness to reduce the sulphur emissions. Although information from other regions would indicate that these fuel specifications will increase CO₂ emissions, no studies have been found to forecast the exact impact of AFRI-4. Analysing the effect of fuel specification changes on CO₂ and climate change mitigation in developing regions is an area for further work.

6.2 IMO MARPOL Fuel Specification Changes

The International Maritime Organization (IMO) has proposed a reduction to the maximum permitted sulphur content of marine fuels and heavy fuel oil regulated by the MARPOL Protocol. For special SO_x emissions control area's (SECA's), the sulphur content will reduce from 1.0% (10,000ppm) to 0.1% by 2015. Globally, limits outside the SECA's are currently 3.5%, but will progressively reduce to 0.5% by 2020, unless feasibility reviews before 2018 prove it is not worthwhile. As part of the decision making process the IMO engaged EnSys to investigate the international impacts of lower sulphur limits in MARPOL (IMO, 2007). Whilst investigating the impact on the CO₂ emissions of the refining industry in 2020, three scenarios were investigated. The base case is based on IEA estimates



of refined product demand in 2020 before recent financial crisis, so may now be an over estimate. The Multi-SECA case is based on the establishment SECAs around the world and the range reflects different sulphur specifications for the SECAs. The global distillate scenario assumes a switch to distillate fuel for the whole of the maritime fleet to meet the sulphur specification. Table 13 shows the potentially large increase of CO₂ emissions resulting from these scenarios. The shift to distillate for global maritime industry could result in a nearly 11% increase in refinery CO₂ emissions, with the SECA scenario's resulting in smaller increases of about 2%.

Table 13: World refining industry CO₂ emissions in 2020, based on different scenarios for changes by the IMO to marine fuel specifications. Source: IMO, (2007)

	IMO Base Case	Multi-SECA case	Global Distillate
Total refinery CO ₂ emissions [Mt/y]	1115	1141-1143	1248
Incremental CO ₂ emissions versus base case [Mt/y]		26-28	133

More specific to Europe, both Pervin and Gertz (2009) and Entec (2010) have studied the likely impacts to the maritime industry. Purvin and Gertz (2009) predict that the IMO regulation will have the impact of increasing the CO₂ emissions from European refineries by 5% in 2015. In 2020 the impact is expected to be a 3% increase in CO₂ emissions, because the increase due to the IMO specification is partly offset by the reduced use of FCC units. Neither of the Purvin and Gertz (2009) scenarios take into account the use of on-board scrubbers for reducing the SO₂ emissions. The most economic method for SO_x abatement for most ships appears to be the installation of on-board SO₂ scrubbers rather than purchasing low sulphur fuel. The price impact in the final product for SECA areas with a 0.1% sulphur content is expected to be €200-€280/tonne which represents a cost increase of 60% to 75%. The use of on-board scrubbing technology is expected to add €100/tonne to the cost of fuel, however technical challenges relating to its implementation raise uncertainty to the extent to which it will be implemented. For this reason Purvin and Gertz (2009) estimates of CO₂ emissions increases probably overstate the actual implications for the refining sector and offer a worst case scenario.

The European study by Entec (2010) also expect a substantial increase in the price of fuel of between €155 and €310, at an average of €230 or around 80% of fuel costs. The total compliance cost associated with switching to low sulphur fuels is estimated to be €3.0-3.6 billion in 2015, with the cost of on-board scrubbing likely to be 20-50% of this cost. Despite the large investment gap between fuel switching and on-board scrubbing, uncertainty relating to availability and reliability of this technology is likely to inhibit its up take by 2015 (Entec, 2010). There is potential for the large investment costs and uncertainty to affect short sea shipping with a move to road and rail freight of potentially 3-50% (Entec, 2010). The potentially greater rise in CO₂ emissions in Europe compared with global emissions is likely related to the proposal to make the Mediterranean a SECA.

6.3 Clean Development Mechanism (CDM)

Under the requirements of the Kyoto Protocol Emission caps have been placed on developed, Annex 1, countries giving each country an emissions quota or allowable amount of CO₂ emissions. Developing (non Annex 1) countries have no requirement to cap their emissions but instead may benefit from CO₂ emission reducing projects financed by Annex-1 countries through the CDM. This is a way for Annex 1 countries to earn credits by investing and funding climate friendly projects and



technologies in developing countries, thus helping control emissions in these countries. Out to 2012 there are registered savings of 3,000 MtCO₂ (Carbon Trust, 2009), but this unlikely to be achieved because of under-achievement of projects and delays in start up. It should be noted that currently CCS does not fall under CDM but there are discussions undergoing in relation to this issue. Should the CDM mechanism evolve to include CCS, it presents a potential mechanism for financing carbon abatement in the refining sector of developing nations in the future. More specifically if CCS is included in the CDM mechanism and what ever it should become under any future agreement that replaces the Kyoto protocol, then it will become even stronger mechanism for financing such projects. Balakrishnan (2009) suggests the key opportunities for CDM funding in the downstream refining sector are:

1. Waste gas and/or heat recover
2. Steam system optimisation
3. Steam trap maintenance
4. Process integration
5. Fuel switching
6. Electrical energy efficiency

6.4 Emissions Trading Schemes

The EU currently has the largest of these schemes in place with only a small proportion of global emissions currently covered. They allow for the trading of CO₂ emissions for carbon credits. If a country or industry exceeds their assigned amount of CO₂ emissions, they would be able to purchase credits from a country or industry that has not. Refineries are covered under the EU-ETS, however, they have been granted free permits under initial phases, in an attempt to prevent carbon leakage. How this will develop in the future is uncertain, but if the current trend of tightening the EU-ETS and disallowing free handouts of credits is continues, refineries will be faced with a choice of having to buy permits or reduce emissions, which may lead to an incentive to deploy CCS.

6.5 Carbon Leakage Mechanisms

Refineries operate with tight margins: In Europe and Asia these rarely rose above \$US5/bbl for much of the 90's and early 00's (See Figure 8), so any additional costs push the industry. At €20/tCO₂ the impact on the cost of carbon would reach \$US 1/bbl entering the refinery (IEA, 2005), a substantial amount considering the refinery margins in Figure 8. The addition of carbon tax or an emissions trading scheme has the potential to encourage importation of product from regions not covered by the same schemes, thus defeating the purpose of the emissions reduction legislation. Some organisations have proposed schemes to add the cost of carbon to imports from regions that do not have legislation in place to put the cost of carbon into the price of a product. The refining sector is expected to be at risk of suffering from this mechanism and at present, it is currently addressed in the EU by allocating free allowances to the refining industry. In the future, as allowances are reduced, many EU-based refineries are expected to reduce production to meet their allocation, and input shortfalls, if no other mechanism to protect them is introduced.

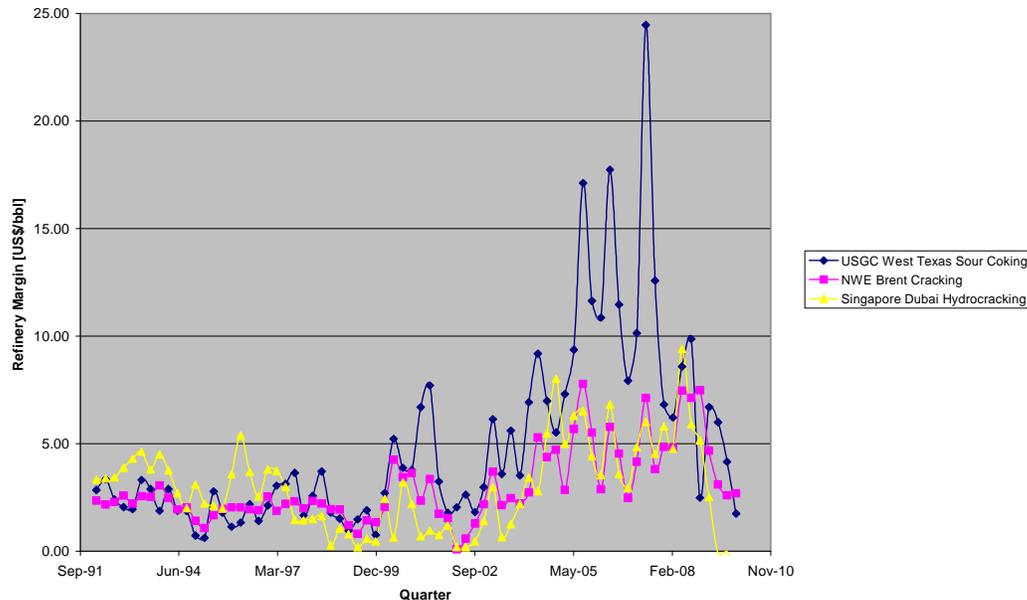


Figure 8: Quarterly refining margins for three major refining products since the early 90's. The products show Asian, European and North American. Source: BP 2009 Statistical Review of World Energy.

7 CONCLUSIONS

There is an interest from the refining sector in CCS, as indicated by initiated demonstration projects in North America and Europe such as the North West Refining project in Canada and the Air Products project in Port Arthur, Texas, the European Test Centre (TCM), Mongstad, Norway and the Rotterdam Climate Initiative, which is likely to include Shell Refinery emissions.

One challenge facing research on CCS in refineries, however, is the lack of consistent data on refinery sector emissions. This is largely due to uncertainties in the existing IEA-GHG emissions database and concerns in particular the operating proportion of the plants and the emissions factors of the plants. Further work is required to form a more comprehensive database of existing refinery emissions and their uncertainty. Based on the emissions inventories, further work is required to anticipate future refinery CO₂ emissions, and hence the role of CCS.

CCS is a technically feasible technology for reducing the CO₂ emissions from the refining sector through a range of post combustion, pre-combustion and oxy-fuel technologies. At present, however there are a number of challenges that need to be overcome which are hindering widespread deployment of CCS. In this assessment, barriers identified include policy, finance issues, and technical barriers. Technical challenges relate to the numerous small distributed emission sources on a refinery site and the space required to deploy CCS. These technical barriers are behind the relatively high predicted deployment costs for CCS in most unit operations in the refining sector. Promising technologies are in development that could reduce these costs, but commercial demonstration will be the measure of real feasibility. Potential for early deployment of CCS in refineries exists for some high purity CO₂ streams, which are a by-product of certain hydrogen production processes, because

they require little processing and hence have low capture costs. Transport related emissions including refining in China, India and rest of world including Middle East, Africa and Latin America have potential to grow, hence there is potential for greenfield CCS deployment in these regions. In more established markets such as the OECD, potential CCS deployment may be for retrofit of existing refineries.

Note that policies that could encourage CCS in the refining sector have the potential to also reduce the demand for transport fuels, and hence reduce the output and emissions from the refining sector. Other legislation such the IMO MARPOL and transport fuel quality legislation is implemented to reduce the environmental impacts of emissions such as SO_x, NO_x, and particulate mater. The extra processing required to achieve these targets, however, are leading to an increases in the CO₂ emissions of the refining sector globally.

A more detailed analysis of the gaps and barriers to the deployment of CCS in the refining industry has been undertaken in a structured process. Actions and milestones to overcome these have also been identified as part of this process and these are outlines in the following sections.

7.1 Major Gaps and Barriers to Implementation

This section focuses on the major gaps and barriers specific to the refining sector and also those that relate to other sectors¹. The major gaps and barriers specific to refining industry are:

- CCS technology needs to be tested and demonstrated in the sector, specifically on integration with existing operations. In addition it would benefit the sector to have a set of early projects financially supported by Government or regulatory body, to help commercial deployment.²
- Regarding capture-ready design of new refineries: There is a need for incentives and design guidelines for building capture ready refineries.
- Multiple CO₂ sources and specifications is a unique characteristic of the refining industry and hence different technologies may need to be implemented depending on source
- There is a lack of space on many refineries for installing new equipment, especially for large diameter pipe work and new units likely to be required for CCS.
- International oil companies and state owned refineries have different motivations for installing environmental technology. The implication of plant ownership on prospects of implementation of CCS technology need to be recognized and addressed
- The persistently low refining margins will make additional emission-related investment a challenging decision without clear government supported cost recovery mechanisms.²
- Refineries age, particularly old refineries in the OECD, and potentially limited lifetimes may make it hard to financially justify implementing new capture technology.
- The issue of carbon leakage is a significant issue when regional mitigation is to be imposed.
- Non-conventional liquid fuels are expected to have a large impact on the sector, which may restrict new build in coming decades.

Issues which are more commonly related to all sectors are:

¹ Based on discussions at the Roadmap workshop in Abu Dhabi. During the second session of the Abu Dhabi meeting Alice Gibson of Global CCS Institute moderated discussions which focused on issues specific to refining sector and more general issues.

² Modified by reviewer

- General lack of training of CCS for technical professionals and managers
- Water & electrical supply security.
- CO₂ specifications for sinks can always be met albeit at cost.
 - o (Need guidelines for CO₂ specification final use and this needs to reflect regional needs)
- International Legislation – to do with liability, both short and long term. Initially local regulations may be used, but international regulations are required in the long term.
- Due to described inherent limitations, the costs of capture of CO₂ from refineries are expected to be significantly higher than costs from eg. power plants.³

7.2 Actions and Milestones

The perceived major actions and milestones for the refining sector are the following⁴:

Actions

- Comprehensive emissions inventory need to be developed and standard methodologies for calculating need to be universally accepted.
- All low cost emissions abatement should be addressed to reduce capture inventory
- There is a need to characterise unique emissions specifications of each unit operation in order to better determine the relevant technology.
- Develop specific training requirements and programs for the engineers involved in the application and adapt existing qualifications to include the new CCS industry.
- Develop guidelines and specifications for both retrofit and capture ready that are specific to refineries
- Conduct comprehensive pilot demonstrations to prove the technology in the sector as refineries are not identical
- Knowledge transfer is required, specifically risk management from other areas where new technology is used regularly
- There is a lack of information specific to the refining sector, hence there is a need for more detailed study into the prospects and projections for CCS and other carbon abatement technologies, for refining under different scenario's⁵.
- Consolidate and disseminate JIP's for CCS for the refinery sector⁶

³ Additional action identified by reviewer

⁴ Based on discussions at the Roadmap workshop in Abu Dhabi. The third session moderated by Dolf Geilen of UNIDO was dedicated to identifying actions and milestones specific to the refining sector for role out CCS.

⁵ Additional action identified by the author.

⁶ Additional action identified by reviewer

Milestones

Milestones are not addressed in an order of priority. Milestones that can easily be carried out by forums such as that organised by UNIDO in the short term out to 2012 are:

- Follow up with IEA-GHG programme to identify how the above recognised issues may be addressed within their research programs.
- Organize specific workshops with refinery technology providers to review how CCS can be integrated in their designs
- Find local champions to further the cause of CCS in the developing regions
- Plan a timeline for demonstrating the technology in the refining sector

Milestones that will require global agreements in forums such as the UNFCCC process include:

- Achieving a global agreement on emissions reduction and more specifically the implementation of the technology in refineries.
- Developing mechanisms to support technology transfer from developed to developing regions and devising financing mechanisms
- Develop industry agreement for the implementation of the technology in refineries.
- Disseminate information to developing regions as it becomes available from developed nations
- Develop local knowledge in CCS through enhanced technology transfer and training

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