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Evaluating the Costs of Retrofitting CO_2 Captured in an Integrated Oil Refinery: Technical Design Basis and Economic Assumptions

IEA GREENHOUSE GAS R&D PROGRAMME

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The IEAGHG manager for this report was:

- John Gale

The report should be cited in literature as follows:

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INTRODUCTION & BACKGROUND OF THE PROJECT

In the past years, IEA Greenhouse Gas R&D Programme (IEAGHG) has undertaken a series of projects evaluating the performance and cost of deploying CO_2 capture technologies in energy intensive industries such as the cement, iron and steel, hydrogen, pulp and paper, and others.

In line with these activities, IEAGHG has initiated this project in collaboration with CONCAWE, GASSNOVA (via CLIMIT Programme) and SINTEF Energy Research, to evaluate the performance and cost of retrofitting CO_2 capture in an integrated oil refinery.

The project will be managed and implemented by SINTEF Energy Research. The project consortium has selected Amec Foster Wheeler as the engineering contractor to work with SINTEF in performing the basic engineering and cost estimation for the reference cases.

The main purpose of this study is to evaluate the cost of retrofitting CO_2 capture in simple to high complexity refineries covering typical European refinery capacities from 100,000 to 350,000 bbl/d. Specifically, the study will aim to:

- Formulate a reference document providing the different design basis and key assumptions to be used in the study.
- Define 4 different oil refineries as Base Cases. This covers the following:
  - Simple refinery with a nominal capacity of 100,000 bbl/d.
  - Medium to highly complex refineries with nominal capacity of 220,000 bbl/d.
  - Highly complex refinery with a nominal capacity of 350,000 bbl/d.
- Define a list of emission sources for each reference cases and agreed on CO_2 captures priorities.
- Investigate the techno-economics performance of the integrated oil refinery (covering simple to complex refineries, with 100,000 to 350,000 bbl/d capacity) capturing CO_2 emissions from various sources using post-combustion CO_2 capture technology based on standard MEA solvent.
- Investigate the techno-economics performance of a medium to high conversion refineries (220,000 bbl/d capacity) capturing CO_2 emissions using pre-combustion CO_2 capture technology capturing CO_2 emissions from the hydrogen production facilities (as base case). A sub-case will also be evaluated to assess the possibility to increase capture rate based on the principle of expanding the hydrogen production facility and the conversion of fired heaters and utilities boilers using hydrogen enriched fuel.
- Investigate the techno-economics performance of an integrated oil refinery (covering medium to high conversion complex refineries with 220,000 bbl/d) capturing CO_2 emissions using oxyfuel combustion technology applied the Fluid Catalytic Cracker (as base case). A sub-case will also be evaluated to assess the possibility to increase capture rate using oxyfuel combustion application to various fired heaters.
- Develop a case study evaluating the constructability of retrofitting CO_2 capture in a complex oil refinery providing key information on the following (but not limited to):

plant layout, space requirement, safety, pipeline network modification, access route for equipment, modular construction vs. stick-built fabrication, and others.

The project has developed two reference documents that outline the technical basis of the design of the refinery and the capture equipment that are used in the subsequent economic modelling of the capture retrofit to an integrated oil refinery. This report provides the details of these reference assumptions. Reference Documents 1 & 2 that follow provide detailed information about the mass and energy balances, carbon balance, techno-economic assumptions, data and evaluation, and CO_2 avoidance cost; that could be adapted and used for future economic assessment of CCS deployment in the oil refining industry.

This reference document will be publically shared by the project partners for reference and use by third parties. The project partners want the data set used in this study to be fully transparent to allow the methodology of cost assessment in a complex industrial site developed by the project to be openly accessible and thus be used by third parties as a basis for further studies in the future.

Evaluating the Cost of Retrofitting CO_2 Capture in an Integrated Oil Refinery

Reference Document 1: Technical Design Basis

Responsible Organization:

IEA Greenhouse Gas R&D Programme
Cheltenham, UK

Deliverable Date:
April 2017

Project Partners:

Project Management, Implementation and Delivery:

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Evaluating the Cost of Retrofitting CO_2 Capture in an Integrated Oil Refinery

Reference Document 1: Technical Design Basis

I N D E X

1 REFERENCE DOCUMENT OVERVIEW

The purpose of this report is to present a reference document that describes the technical basis and key assumptions to be used in evaluating the performance of the integrated oil refinery without and with CO_2 capture.

The engineering and design basis, and various assumptions on feedstock, additives, products and by-products, and the specification of the CO_2 that are outlined in this report will be used as a reference for developing the refinery configurations to be developed in the study which will be published once the project is completed.

Where applicable, information retrieved from IEAGHG document "Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions" Version C-6, March 2014, are included.

The refinery configurations to be analyzed as Base Cases include:

- Base Case 1: Simple Hydro-skimming Refinery (Capacity: 100,000 bbl/d)
- Base Case 2: Medium Conversion Refinery (Capacity: 220,000 bbl/d)
- Base Case 3: High Conversion Refinery (Capacity: 220,000 bbl/d)
- Base Case 4: High Conversion Refinery (Capacity: 350,000 bbl/d)

The different block flow diagrams for the different configurations are presented in Annex A. The different feedstock, additives, and supplementary fuel to be used in the study are listed in Section 4 and Annex B. The different products and by-products are enumerated in Section 5 and Annex C.

The primary fuel of the plant are the refinery off-gases and heavy fuel oil[1]. Natural gas will be used as supplementary fuel or feedstock if necessary.

It is expected that the different oil refineries to be evaluated should be self-sufficient to its requirements for:

- electricity
- steam
- hydrogen

Generally, electricity, steam and heat are "exported from" and/or "imported into" the defined battery limit of the refinery. These are very site specific conditions. For simplification to the economic evaluation and accounting of the site's CO_2 emissions, this study would assume that only surplus electricity will be considered. There will no export of steam or heat. Any surplus electricity produced within the site will be sold to the grid.

For this study, all the electricity and steam required by the refinery will be supplied by having a self-sufficient electricity and steam production inside the battery limit from a CHP plant based on either from a steam boiler or gas turbine combined cycle or both. This will be dependent on the requirements of the individual cases and practical considerations.

[1] Regulatory implications to the use of heavy fuel oil as primary fuel relative to the site SOx emissions limits is considered in this study. It has been agreed to follow the requirements stipulated by EU Industrial Emissions Directives (IED) as defined in Section 6.5.1.

2 KEY FEATURES OF THE REFINERY

2.1 Boundary Limit

The definition of the boundary (battery) limit of the integrated oil refinery is essential to formulate a clear account of the overall energy requirements and the direct CO_2 emissions per barrel of crude oil processed.

A schematic representation of the boundary limit, material inputs and outgoing products, by-products and waste are illustrated in the different block flow diagrams as shown in Figures A-1 to A-4 of Annex A.

The different processes and utilities to be included in the battery limit of the refinery without CO_2 capture are summarised in Section 3.2.1. Additional processes to be included in the battery limit of the refinery with CO_2 capture are summarised in Section 3.2.2.

2.2 Key Features of the Oil Refinery without and with CO_2 Capture

2.2.1 Refining Capacities and Unit Processes – Base Cases

The different configurations used for the different Base Case Refineries without CO_2 capture and the unit processes and utilities included in the analysis could be summarised as:

- Base Case 1: Simple Hydro-skimming Refinery
  - Capacity: 100,000 bbl/d (nominal)
  - Major Processes:
    - Unit 100: Crude Distillation Unit (CDU)
    - Unit 200: Saturated Gas Plant (SGP)
    - Unit 250: LPG Sweetening (LSW)
    - Unit 280: Kerosene Sweetening (KSW)
    - Unit 300: Naphtha Hydrotreater (NHT)
    - Unit 350: Naphtha Splitter (NSU)
    - Unit 400: Isomerization Unit (ISO)
    - Unit 500: Catalytic Reformer (CRF)
    - Unit 550: Reformate Splitter (RSU)
    - Unit 600: Kerosene Hydrotreater (KHT)
    - Unit 700: Diesel Hydro-desulphurisation Unit (HDS)
    - Unit 1100: Vacuum Distillation Unit (VDU)
    - Unit 1500: Visbreaker Unit (VBU)
    - Unit 2000: Amine Regeneration Unit (ARU)
    - Unit 2100: Sour Water Stripper Unit (SWS)
    - Unit 2200: Sulphur Recovery Unit (SRU)
    - Unit 2300: Waste Water Treatment (WWT)
    - Unit 2500: Power Plant (Electricity and Steam Production)
    - Unit 3000: Utilities
    - Unit 4000: Off-sites

- Base Case 2: Medium Conversion Refinery
  - Capacity: 220,000 bbl/d

- Major Processes:
  - Unit 100: Crude Distillation Unit (CDU)
  - Unit 200: Saturated Gas Plant (SGP)
  - Unit 250: LPG Sweetening (LSW)
  - Unit 280: Kerosene Sweetening (KSW)
  - Unit 300: Naphtha Hydrotreater (NHT)
  - Unit 350: Naphtha Splitter (NSU)
  - Unit 400: Isomerization Unit (ISO)
  - Unit 500: Catalytic Reformer (CRF)
  - Unit 550: Reformate Splitter (RSU)
  - Unit 600: Kerosene Hydrotreater (KHT)
  - Unit 700: Diesel Hydro-desulphurisation Unit (HDS)
  - Unit 800: Vacuum Gasoil Hydrotreater Unit (VHT)
  - Unit 1000: Fluid Catalytic Cracker (FCC)
  - Unit 1050: FCC Gasoline Post-Treatment Unit (PTU)
  - Unit 1100: Vacuum Distillation Unit (VDU)
  - Unit 1200: Steam Methane Reformer (SMR)
  - Unit 1500: Visbreaker Unit (VBU)
  - Unit 2000: Amine Regeneration Unit (ARU)
  - Unit 2100: Sour Water Stripper Unit (SWS)
  - Unit 2200: Sulphur Recovery Unit (SRU)
  - Unit 2300: Waste Water Treatment (WWT)
  - Unit 2500: Power Plant (Electricity and Steam Production)
  - Unit 3000: Utilities
  - Unit 4000: Off-sites

- Base Case 3: High Conversion Refinery
  - Capacity: 220,000 bbl/d
  - Major Processes:
    - Unit 100: Crude Distillation Unit (CDU)
    - Unit 200: Saturated Gas Plant (SGP)
    - Unit 250: LPG Sweetening (LSW)
    - Unit 280: Kerosene Sweetening (KSW)
    - Unit 300: Naphtha Hydrotreater (NHT)
    - Unit 350: Naphtha Splitter (NSU)
    - Unit 400: Isomerization Unit (ISO)
    - Unit 500: Catalytic Reformer (CRF)
    - Unit 550: Reformate Splitter (RSU)
    - Unit 600: Kerosene Hydrotreater (KHT)
    - Unit 700: Diesel Hydro-desulphurisation Unit (HDS)
    - Unit 800: Vacuum Gasoil Hydrotreater Unit (VHT)
    - Unit 900: Hydrocracker Unit (HCK)
    - Unit 1000: Fluid Catalytic Cracker (FCC)
    - Unit 1050: FCC Gasoline Post-Treatment Unit (PTU)
    - Unit 1100: Vacuum Distillation Unit (VDU)
    - Unit 1200: Steam Methane Reformer (SMR)
    - Unit 1400: Delayed Coker Unit (DCU)
    - Unit 2000: Amine Regeneration Unit (ARU)
    - Unit 2100: Sour Water Stripper Unit (SWS)
    - Unit 2200: Sulphur Recovery Unit (SRU)

- Unit 2300: Waste Water Treatment (WWT)
- Unit 2500: Power Plant (Electricity and Steam Production)
- Unit 3000: Utilities
- Unit 4000: Off-sites

- Base Case 4: High Conversion Refinery
  - Capacity: 350,000 bbl/d
  - Major Processes:
    - Unit 100: Crude Distillation Unit (CDU)
    - Unit 200: Saturated Gas Plant (SGP)
    - Unit 250: LPG Sweetening (LSW)
    - Unit 280: Kerosene Sweetening (KSW)
    - Unit 300: Naphtha Hydrotreater (NHT)
    - Unit 350: Naphtha Splitter (NSU)
    - Unit 400: Isomerization Unit (ISO)
    - Unit 500: Catalytic Reformer (CRF)
    - Unit 550: Reformate Splitter (RSU)
    - Unit 600: Kerosene Hydrotreater (KHT)
    - Unit 700: Gasoil Hydro-desulphurisation Unit (HDS)
    - Unit 800: Vacuum Gasoil Hydrotreater Unit (VHT)
    - Unit 900: Hydrocracker Unit (HCK)
    - Unit 1000: Fluid Catalytic Cracker (FCC)
    - Unit 1050: FCC Gasoline Post-Treatment Unit (PTU)
    - Unit 1100: Vacuum Distillation Unit (VDU)
    - Unit 1200: Steam Methane Reformer (SMR)
    - Unit 1300: Solvent Deasphalting Unit (SDA)
    - Unit 1400: Delayed Coker Unit (DCU)
    - Unit 2000: Amine Regeneration Unit (ARU)
    - Unit 2100: Sour Water Stripper Unit (SWS)
    - Unit 2200: Sulphur Recovery Unit (SRU)
    - Unit 2300: Waste Water Treatment (WWT)
    - Unit 2500: Power Plant (Electricity and Steam Production)
    - Unit 3000: Utilities
    - Unit 4000: Off-sites

2.2.2 Additional Unit Processes – Oil Refinery with CO_2 Capture Cases

The project has a focus on evaluating the cost of retrofitting CO_2 capture in a refinery. The refinery will be retrofitted for CO_2 capture from the following units:

1. Major refinery fired heaters
2. Fluid Catalytic Cracker (FCC)
3. Steam reformer for H_2 production
4. CHP plant

An end-of-pipe CO_2 capture scenario using mono-ethanol amine (MEA) is considered the most mature technology for CO_2 capture. This capture technique will be applied to all the units listed above. Different capture scenarios will be developed to cover a range of CO_2 capture ratios from these different process units. Plot plan and stack layout considerations in addition to the size of the emissions will be taken into account in defining the capture scenarios of each base case refinery.

Another CO_2 capture route that will be considered in this project is CO_2 capture from the syngas for H_2 production in the steam reformer. The main scenario for this capture route is only capture from existing steam methane reformers.Additionally, scenarios will be considered where the fuel for the major fired heaters are switched to a mixture of H_2 and refinery fuel gas as a way to decrease CO_2 emissions from these process units.Additional H_2 production capacity with CO_2 capture will be considered for the latter scenarios.

Oxy-combustion technology, where the oxidising agent is highly pure oxygen rather than air, can also be used to reduce CO_2 emissions in refinery. The capture route will mainly be applied to the FCC unit. Additionally, scenarios will be considered for converting major fired heaters to utilize oxy-combustion.

Details of the different scenarios will be arrived at after performig the base case refinery balances and developing their plot plan and layouts.

The additional unit processes and utilities to be included in the analysis for oil refineries with CO_2 capture could be summarized as:

- Post-Combustion Capture Cases
  - Major Processes:
    - Unit 5000: CO_2 Capture System
    - Unit 7000: CO_2 Compression and Drying Unit

- Pre-Combustion Capture Cases
  - Major Processes:
    - Unit 6000: (Reserved for ATR)
    - Unit 7000: CO_2 Compression and Drying Unit

- Oxyfuel Combustion Capture Cases
  - Major Processes:
    - Unit 8000: Air Separation Unit
    - Unit 9000: CO_2 Processing Unit

2.2.3 Utility and Off-site Units

The different utility and offsite units considered in the study include the following:

- Cooling Water System
- Steam System
- Demineralized, Condensate Recovery Water Systems
- Plant/Instrument Air Systems
- Inert Gas System
- Fuel gas System
- Fuel Oil System
- Fire Fighting System
- Flare system
- Interconnecting (ducting/piping/cables, etc…)
- Tank Farms
    - Feedstock Storage
    - Intermediate Storage
    - Product Storage
- Additives Handling and Storage
    - Bio-ethanol
    - Bio-diesel
    - MTBE
- Sulfur Handling and Storage
- Coke Handling and Storage
- Chemicals

2.3 Seasonal Variations

Typical oil refineries operate with seasonal variations to meet varying demand of products during certain period of the year.

However, this study will only evaluate annual production average and will not include any seasonal variations into considerations for its production.

2.4 Capacity Factor

This study assumed that the oil refinery will achieved 350 days of full operation per year.

During the construction and retrofit of the CO_2 capture plant, it is desired to have minimum impact to the normal operation of the refinery in order to reduce the economic loss due to reduced or lost production period.

Thus, this study assumed that the construction and commissioning of the CO_2 capture plant should be implemented during pre-turnaround schedule. All modifications and connection work required should be undertaken during the general turnaround schedule.

However, in cases where completion of the retrofit work will require longer general turnaround period, then the capacity factor of the refinery will be adjusted accordingly based on the analysis and recommendations provided by Amec Foster Wheeler.

3 FEEDSTOCK AND ADDITIVES SPECIFICATIONS

3.1 Crude Oil

The following crude oil selected for this project is enumerated below.

- Ekofisk
- Bonny Light
- Arabian Light
- Urals Medium
- Arabian Heavy
- Maya Blend (50% wt. Maya Oil with 50% wt. Arabian Light).

This represents a suite of very light to heavy crude and sweet to sour crude typically used in European refineries.

Figure 1 below presents the distillation curve of the different crude oil selected. Table 4 presented next page summarized the main crude oil properties.

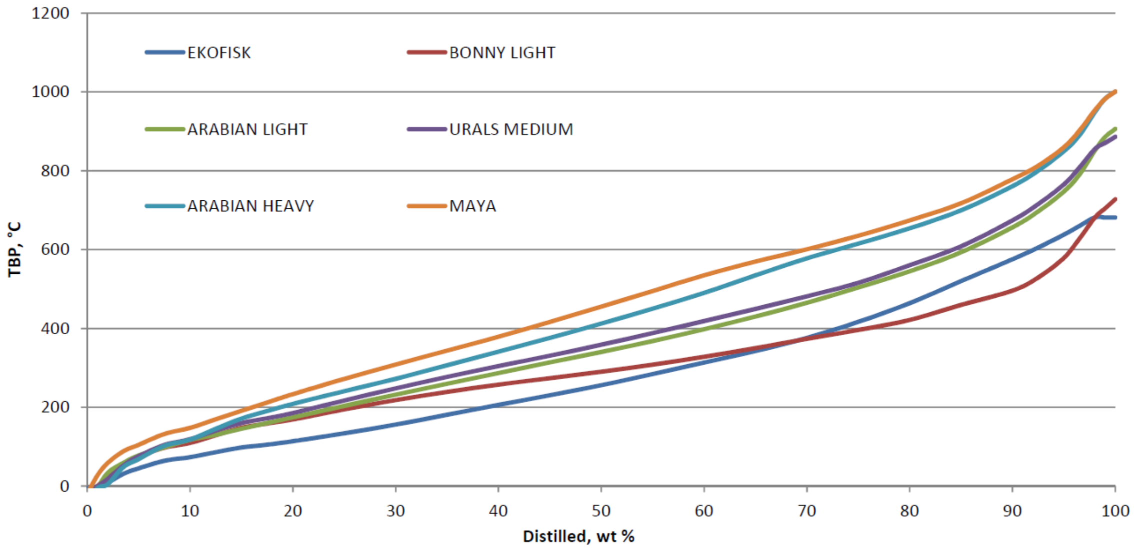


Figure 1: Distillation curves of the different crude oil selected for this project

Table 4: Summary of Crude Oil Properties (Data from Amec FW)

EKOFISK

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-5.8	32.8	268.3	0.000
1	0.2	36.2	582.2	0.000
2	8.9	41.5	589.8	0.000
3.5	30.9	55.9	711.0	0.000
5	45.1	66.3	715.4	0.000
7.5	64.2	81.0	722.6	0.000
10	73.4	88.4	729.5	0.000
12.5	86.0	99.1	736.3	0.000
15	97.9	109.1	742.8	0.001
17.5	105.0	115.5	749.2	0.001
20	113.8	123.2	755.2	0.002
25	133.9	141.4	766.9	0.003
30	156.1	161.5	778.8	0.005
35	180.9	184.1	789.9	0.006
40	206.0	207.0	798.3	0.008
45	230.5	229.4	807.1	0.021
50	256.0	252.5	820.3	0.045
55	284.2	277.7	839.6	0.069
60	313.5	303.8	854.3	0.092
65	342.6	329.9	866.3	0.166
70	375.9	361.4	879.9	0.249
75	416.7	401.3	892.7	0.296
80	464.1	447.1	901.5	0.331
85	520.1	497.6	912.8	0.440
90	575.6	542.0	924.5	0.525
92.5	605.3	562.4	929.8	0.596
95	638.0	581.6	937.2	0.676
96.5	659.8	592.2	942.4	0.728
98	681.5	601.2	947.9	0.783
99	681.5	601.2	951.5	0.819
100	681.5	601.2	955.1	0.855

BONNY LIGHT

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-30.1	18.6	349.7	0.000
1	-0.7	37.2	582.8	0.000
2	27.1	57.9	657.0	0.002
3.5	55.3	78.1	724.7	0.002
5	75.2	93.9	734.7	0.003
7.5	97.3	112.3	750.3	0.005
10	109.5	122.6	764.7	0.007
12.5	129.0	139.6	778.0	0.008
15	148.1	156.5	790.1	0.010
17.5	158.6	165.9	800.8	0.013
20	169.0	175.3	810.4	0.016
25	194.6	198.6	826.4	0.023
30	218.2	219.9	838.5	0.031
35	239.0	238.7	847.5	0.038
40	257.4	255.4	854.8	0.045
45	273.9	270.5	861.0	0.054
50	290.1	285.5	866.1	0.061
55	308.0	302.1	870.3	0.086
60	328.1	320.9	881.0	0.145
65	350.2	341.7	900.1	0.185
70	373.6	363.9	913.4	0.210
75	396.0	385.4	922.6	0.229
80	421.6	410.1	931.7	0.248
85	459.7	446.1	939.0	0.273
90	496.0	474.4	958.6	0.306
92.5	529.2	494.3	970.4	0.333
95	578.9	527.1	998.3	0.403
96.5	627.5	565.6	1023.0	0.445
98	681.2	596.0	1052.6	0.485
99	704.5	602.6	1074.1	0.511
100	727.7	609.3	1095.6	0.537

ARABIAN LIGHT

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-29.5	21.7	291.3	0.000
1	-4.0	37.9	657.0	0.077
2	33.8	64.4	667.9	0.070
3.5	58.9	83.6	683.5	0.060
5	77.6	98.5	698.1	0.051
7.5	98.5	115.7	720.5	0.039
10	117.5	131.9	740.5	0.032
12.5	130.4	143.1	757.9	0.030
15	145.4	156.3	772.1	0.031
17.5	160.1	169.4	782.7	0.038
20	174.5	182.4	790.8	0.048
25	203.5	208.6	804.0	0.070
30	232.0	234.2	821.5	0.112
35	259.6	259.0	835.4	0.223
40	286.9	283.6	840.5	0.676
45	314.0	308.0	854.1	1.061
50	340.3	331.4	877.9	1.479
55	368.0	356.0	894.4	2.119
60	398.0	382.5	906.6	2.525
65	430.2	411.3	916.8	2.608
70	465.2	444.0	928.1	2.714
75	503.9	481.0	940.3	2.849
80	545.1	521.0	953.1	3.165
85	593.4	566.5	966.4	3.625
90	656.6	614.6	980.3	4.234
92.5	697.0	635.8	987.5	4.592
95	747.5	669.7	994.7	4.985
96.5	790.0	702.8	999.2	5.237
98	850.7	738.1	1004.5	5.503
99	885.5	746.1	1012.5	5.687
100	906.3	754.0	1025.6	5.875

URALS MEDIUM

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-33.1	21.2	344.6	0.000
1	-1.6	41.5	580.9	0.000
2	18.0	55.2	690.1	0.003
3.5	51.7	80.3	700.6	0.000
5	75.8	99.2	710.8	0.000
7.5	104.4	122.7	726.9	0.000
10	119.0	135.0	742.1	0.009
12.5	140.6	153.6	756.4	0.023
15	160.1	170.7	769.8	0.044
17.5	172.0	181.3	782.2	0.064
20	185.4	193.3	793.6	0.091
25	217.1	221.9	813.3	0.236
30	248.0	249.5	830.4	0.422
35	277.1	275.5	845.9	0.692
40	304.5	300.1	860.3	1.002
45	330.8	323.6	874.3	1.361
50	358.7	348.4	887.9	1.611
55	388.2	374.5	900.9	1.662
60	418.7	401.5	913.2	1.708
65	449.5	429.2	924.5	1.844
70	481.6	459.1	934.5	2.037
75	515.7	491.8	944.3	2.314
80	560.5	534.3	959.3	2.575
85	608.4	578.4	981.3	2.818
90	674.2	634.9	1009.5	3.094
92.5	715.4	666.8	1025.9	3.243
95	765.4	700.9	1043.9	3.398
96.5	807.9	723.4	1055.1	3.495
98	854.9	743.6	1066.9	3.594
99	870.6	748.2	1076.5	3.662
100	886.3	752.7	1086.5	3.730

ARABIAN HEAVY

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-54.2	17.0	325.0	0.000
1	-6.0	44.5	567.4	0.000
2	4.7	53.5	504.2	0.016
3.5	47.7	84.0	659.4	0.009
5	68.5	99.8	678.3	0.001
7.5	102.2	126.5	707.3	0.000
10	118.0	139.5	733.1	0.004
12.5	145.4	162.6	755.6	0.035
15	171.2	184.8	775.2	0.070
17.5	190.4	201.7	792.1	0.105
20	208.6	217.7	806.7	0.180
25	240.8	246.3	830.8	0.587
30	272.2	273.6	852.6	1.123
35	306.6	303.6	872.5	1.666
40	341.2	334.1	891.8	2.154
45	375.9	365.2	904.0	2.501
50	412.5	398.7	911.9	2.542
55	450.1	433.6	933.0	2.645
60	490.3	471.1	948.4	2.785
65	534.7	513.1	960.8	3.094
70	578.0	555.0	977.9	3.514
75	615.1	590.9	994.4	4.083
80	653.9	627.7	1010.1	4.780
85	699.8	669.6	1025.9	5.606
90	761.0	721.6	1041.8	6.561
92.5	800.4	752.0	1049.7	7.087
95	849.6	785.9	1057.7	7.645
96.5	889.9	809.1	1062.5	7.995
98	948.2	835.5	1067.7	8.357
99	982.8	843.2	1075.4	8.604
100	1000.9	850.9	1088.4	8.855

MAYA

Percent	TBP [C]	ASTM D86	Density	Sulphur
0	-19.4	46.4	334.3	0.000
1	27.2	74.8	605.2	0.039
2	58.9	96.4	694.7	0.040
3.5	88.2	117.8	707.0	0.063
5	104.7	130.3	716.2	0.080
7.5	132.2	152.0	734.4	0.119
10	147.8	164.7	752.9	0.194
12.5	169.5	182.7	775.5	0.297
15	190.8	200.8	792.1	0.383
17.5	212.2	219.4	804.5	0.556
20	233.2	237.9	816.7	0.827
25	272.0	272.4	840.6	1.465
30	308.5	304.4	868.1	2.042
35	343.7	335.6	899.9	2.458
40	378.9	367.2	918.9	2.635
45	416.4	401.2	930.6	2.726
50	455.3	437.2	939.8	2.831
55	494.9	474.1	954.7	3.030
60	534.6	511.3	972.0	3.299
65	569.7	544.7	991.7	3.633
70	600.9	575.0	1013.9	4.030
75	636.2	608.3	1038.5	4.490
80	674.0	645.2	1065.6	5.015
85	717.7	685.4	1095.1	5.603
90	778.5	737.1	1127.0	6.254
92.5	813.0	764.0	1143.9	6.604
95	859.9	796.3	1161.6	6.970
96.5	901.6	819.9	1171.7	7.197
98	953.3	842.2	1182.8	7.430
99	982.3	849.7	1195.0	7.588
100	1001.0	857.2	1210.7	7.748

THEORETICAL YIELDS

Ekofisk:

Name	Begin T [C]	End T [C]	Fraction
Off Gas	-6	10	2.1%
Lt St Run	10	80	9.3%
Naphtha	80	150	17.3%
Kerosene	150	240	18.2%
Light Diese	240	360	20.8%
Heavy Dies	360	380	2.8%
LVGO	380	420	4.8%
HVGO	420	530	10.5%
Residue	530	681	14.1%
			100.0%

Bonny Light:

Name	Begin T [C]	End T [C]	Fraction
Off Gas	-30	10	1.4%
Lt St Run	10	80	4.2%
Naphtha	80	150	9.9%
Kerosene	150	240	19.8%
LGO	240	360	31.8%
HGO	360	380	4.3%
LVGO	380	420	8.3%
HVGO	420	530	12.8%
Residue	530	728	7.5%
			100.0%

Arabian Light:

Name	Begin T [C]	End T [C]	Fraction
Off Gas	-29	10	1.3%
Lt St Run	10	80	3.9%
Naphtha	80	150	10.5%
Kerosene	150	240	15.7%
LGO	240	360	22.1%
HGO	360	380	3.5%
LVGO	380	420	6.4%
HVGO	420	530	14.8%
Residue	530	906	21.8%
			100.0%

Urals Medium:

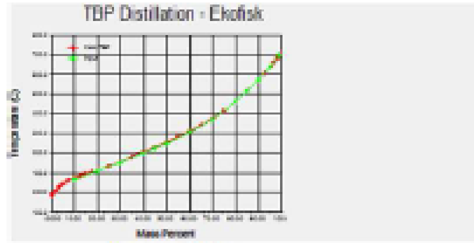
Name	Begin T [C]	End T [C]	Fraction
Off Gas	-33	10	1.6%
Lt St Run	10	80	3.8%
Naphtha	80	150	8.2%
Kerosene	150	240	15.1%
LGO	240	360	21.5%
HGO	360	380	3.4%
LVGO	380	420	6.6%
HVGO	420	530	16.5%
Residue	530	886	23.3%
			100.0%

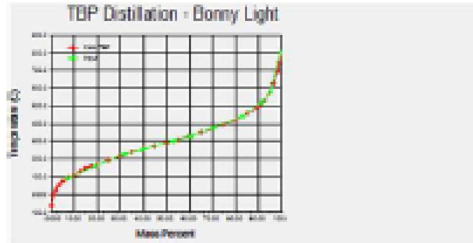
Arabian Heavy:

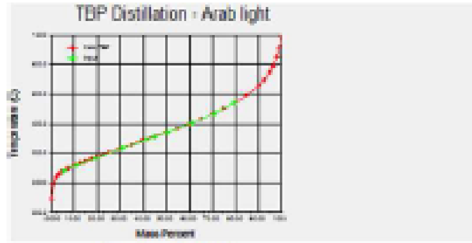
Name	Begin T [C]	End T [C]	Fraction
Off Gas	-54	10	2.2%
Lt St Run	10	80	3.7%
Naphtha	80	150	7.1%
Kerosene	150	240	12.0%
LGO	240	360	17.9%
HGO	360	380	2.8%
LVGO	380	420	5.4%
HVGO	420	530	13.5%
Residue	530	1001	35.5%
			100.0%

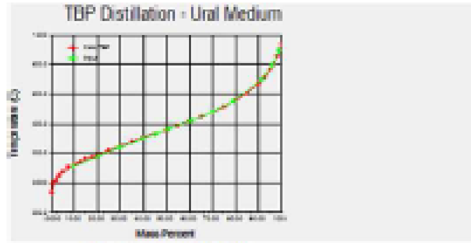
Maya:

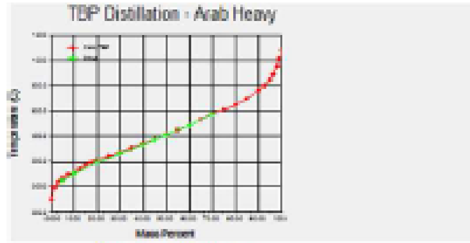
Name	Begin T [C]	End T [C]	Fraction
Off Gas	-19	10	0.6%
Lt St Run	10	80	2.4%
Naphtha	80	150	7.3%
Kerosene	150	240	10.5%
LGO	240	340	13.6%
HGO	340	380	5.7%
LVGO	380	420	5.3%
HVGO	420	530	13.9%
Residue	530	1001	40.6%
			100.0%

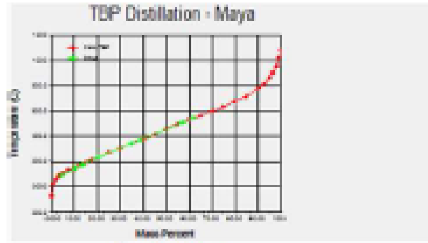


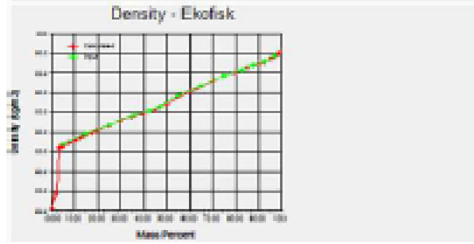


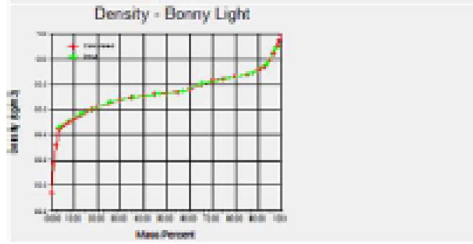


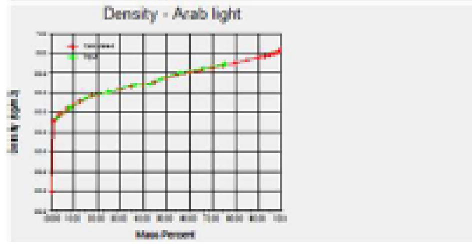


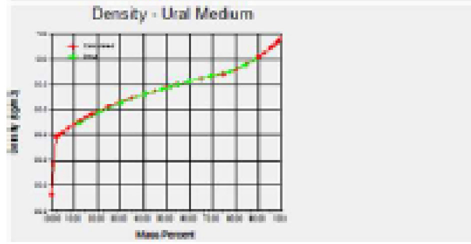


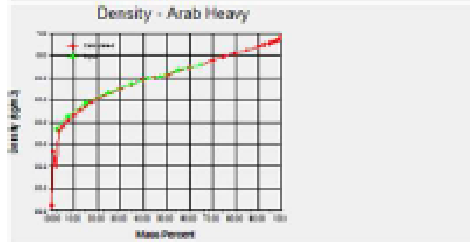


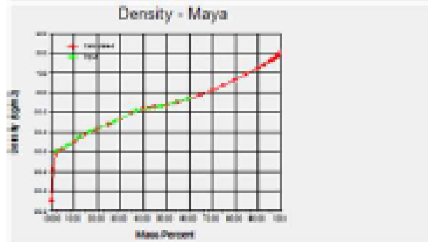












As specified below, the complete crude oil properties the key properties of the main crude fractions are reported in Annex B.

- Crude Oil Data Assay
    - Specific gravity
    - Reid Vapor Pressure (RVP)
    - Viscosity at 20^{o}C, 40^{o}C
    - Pour Point
    - Ultimate Analysis (C, H, O, N, Ash, S)
    - H_2S content
    - Salt, sediment and water content
    - Total N content
    - Acidity
    - Wax and Asphaltene contet
    - CCR
    - Ni, V, other metals content
    - Analysis of light HC content

- Distribution Curves of the Crude Oil
    - True Boiling Point curve (by volume and weight)
    - Specific gravity
    - Sulfur
    - Molecular Weight
    - Viscosity @ 50, 100 °C

3.2 Natural Gas

Natural gas will be used as supplementary fuel or feedstock to the oil refinery to be evaluated. Table herewith presents its properties.

Table 6 Natural Gas Properties

Natural Gas Analysis (vol.%)	
Methane	89.0
Ethane	7.0
Propane	1.0
Butane	0.1
Pentane	0.01
CO_2	2.0
Nitrogen	0.89
Sulfur (as H_2S)	5 ppmv*
Total	**100.00**

HHV, MJ/kg	51.473
LHV, MJ/kg	46.502

Conditions at plant B.L.	
Pressure, Bar	70.0

*5 ppm_v of H_2S are assumed to be present in the Natural gas for design purposes

3.3 Imported Intermediate Products

3.3.1 Vacuum Gasoil

Vacuum gasoil could be imported if needed to saturate the heavy gasoil conversion units (e.g. Fluid Catalytic Cracking). The properties of the imported VGO are considered to be similar to the VGO properties obtained from Urals Crude. See Annex B for details.

3.4 Additives and Process Chemicals

The following additives and process chemical used in the refineries are:

- Bio-ethanol
- Bio-diesel
- Sulphuric Acid
- Caustic Soda

4 PRODUCTS AND BY-PRODUCTS SPECIFICATIONS

4.1 Refinery Products

The refinery products to be considered in this study are enumerated below:

- LPG
- Propylene
- Gasoline U95 Europe
- Gasoline U92 USA Export
- Jet fuel
- Road Diesel
- Marine Diesel
- Heating Oil
- Low Sulphur Fuel Oil
- Medium Sulphur Fuel Oil
- High Sulphur Fuel Oil
- Coke Fuel Grade
- Sulphur

These products are typically produced by European refineries. Annex C presents the different specifications of the refinery products to be sold to the market.

Low Sulfur Fuel Oil is assumed to be used as the only liquid fuel burnt within the refinery. Composition and fuel properties of the low sulfur oil is presented in Table 7.

Table 7: Properties of Fuel Oil

Low Sulfur Fuel Oil Analysis (wt. %)	
C/H Ratio	7.671
Sulfur	0.50
Ash	0.80
Total	**100.00**

HHV, MJ/kg	43.39
LHV, MJ/kg	40.96
API Gravity	17.40

4.2 Refinery Off-Gases

Various off-gases is expected to be produced by various processes. Generally, all off-gases are used as primary fuel of the refinery. Any off-gases that are not used are flared. However, minimum flaring is expected and assumed in this study.

Table 8 below presents the typical range of properties of the refinery off-gas. It should be noted that the composition of the off-gases are very specific to the process units where they are derived.

Table 8: Properties of Refinery Off-Gases (Typical Range)

Refinery Off-Gas Analysis	Range (wt.%)	Average [(1)] (wt.%)	Average [(1)] (vol.%)
Hydrogen (H_2)	2 – 12	8.0	60.9
Methane (CH_4)	4 – 20	12.0	11.5
Ethane (C_2H_6)	12 – 24	18.0	9.2
Propane (C_3H_8)	22 – 26	24.0	8.4
Butane (C_4H_{10})	17 – 59	38.0	10.0
Molecular Weight	10 – 30		15.35
Dew Point at 5 Barg (°C)	-34 / 16		-15
LHV (MJ/kg)	48.116 – 56.484		52.634
H_2S (ppmv)	50 (max.)		50 (max.)

Conditions at Unit B.L.	(See Note 2)	
Pressure (Barg)	Min.	3.0
	Norm.	4.0
	Max.	5.0
	Design	7.0
Temperature (°C)	Min.	-
	Norm.	30
	Max.	45
	Design	130

(1.) Average data shall be used for combustion calculation.
(2.) Pressure and temperature at process unit battery limit.

4.3 Hydrogen

It is expected that oil refinery to be evaluated should be self-sufficient with regard to their on-site hydrogen requirement.

Hydrogen produced from the SMR or other units will have the following properties.

H_2	99.99+% vol. (min)
$CO + CO_2$	10 ppm max
CO	10 ppm max
H_2S, HCl, COS, HCN, NH_3	free
N_2 + Ar	balance
Pressure at B.L.	about 2.5 MPa
Temperature	40 °C

4.4 Electricity

The site is expected to have access to the grid. Any surplus electricity produced on-site will be sold. Table herewith represents the grid connection to the oil refinery.

High voltage grid connection:	380 kV
Frequency:	50 Hz

5 CO_2 SPECIFICATION

CO_2 is delivered from the plant site to the pipeline at the following conditions and characteristics. The CO_2 product purity should be greater than 95%.

Table 9: Properties of CO_2

CO_2 conditions at plant B.L.	
Pressure, MPa	11
Maximum Temperature, °C	30

CO_2 maximum impurities, vol. Basis (0)	
H_2	4% (1,3)
N_2 / Ar	4% (2,3)
CO	0.2% (5)
H_2O	10 ppm (4)
O_2	Case Specific No. (6)
H_2S	20 ppm (4, 7)
SO_X	10 ppm (7)
NO_X	10 ppm (7)

(0) Based on information available in 2012 on the requirements for CO_2 transportation and storage in saline aquifers

(1) Hydrogen concentration to be normally lower to limit loss of energy and economic value. Further investigation is required to understand hydrogen impact on supercritical CO_2 behaviour.

(2) The limits on concentrations of inert are to reduce the volume for compression, transport and storage and limit the increase in Minimum Miscibility Pressure (MMP) in Enhanced Oil Recovery (EOR).

(3) Total non-condensable content (N_2 + O_2 + H_2 + CH_4 + Ar): maximum 4% vol. Basis.

(4) Water specification is to ensure there is no free water and hydrate formation. Likewise to prevent any possibility for corrosion in the presence of corrosive gases such NOx, SOx and H_2S.

(5) H_2S and CO limits are set from a health and safety perspective.

(6) O_2 limit is tentative in view of the lack of practical experience on effects of O_2 in underground reservoirs. EOR may require tighter specification. A discussion on O_2 concentration in the CO_2 product stream will be provided for the different capture scenarios.

(7) SOx, and NOx specification is for a corrosion and pipeline integrity perspective.

6 BASIC ENGINEERING AND DESIGN BASIS

6.1 Plant Location

The site of the plant is assumed to be located at the coast of The Netherlands, with no major site preparation required and no special civil works or constraints on delivery of equipment are assumed.

Plant area is expected to have some restrictions according to typical European refinery setting. This is defined in Task 6.

The site is assumed to have good access to harbor and roads for delivery of raw materials and export of products, by-products and solid waste.

Fresh water supply and high voltage electricity transmission lines, high pressure natural gas pipeline are considered available at plant battery limits.

For cases of oil refineries with CO_2 capture, it is assumed that access to CO_2 pipeline are available at the plant battery limit. Any equipment pertinent to the operation of the pipeline are excluded in the battery limit.

6.2 Site Conditions

- Site Elevation: 6m above mean sea level
- Atmosphere Type: Coastal area with salt pollution.

6.3 Climatic and Meteorological Data

Main climatic and meteorological data are listed in the following. Conditions marked (*) are considered reference conditions for plant performance evaluation.

- Atmospheric pressure 101.3 kPa (*)

- Relative humidity
  - Average 80% (*)
  - Maximum 95%
  - Minimum 40%

- Ambient temperatures
  - Average air temperature 9°C (*)
  - Maximum air temperature 30°C
  - Minimum air temperature -10°C
  - Dry bulb design temperature for air cooled heat exchangers: 25°C

- <u>Wind data: (See Table 10 and Figure 2)</u>
  Wind (Design - Maximum Speed): 35 km/h

<u>Table 10: Wind Profile of the Site</u>

Wind Speed (m/s)	Occurrence (h/y)	Frequency (%)	Cumulative (%)
0-1	224	2.57	100.00
1-2	662	7.59	97.43
2-3	1000	11.47	89.84
3-4	1135	13.01	78.38
4-5	1162	13.32	65.36
5-6	1083	12.42	52.04
6-7	898	10.30	39.62
7-8	743	8.52	29.33
8-9	554	6.35	20.81
9-10	391	4.48	14.46
10-11	286	3.28	9.97
11-12	203	2.33	6.69
12-13	139	1.59	4.37
13-14	94	1.08	2.77
14-15	57	0.65	1.69
15-16	38	0.44	1.04
16-17	22	0.25	0.61
17-18	14	0.16	0.35
18-19	8	0.09	0.19
19-20	4	0.05	0.10
20-21	2	0.02	0.06
21-22	1.4	0.02	0.03
22-23	0.7	0.01	0.02
>23	0.7	0.01	0.01

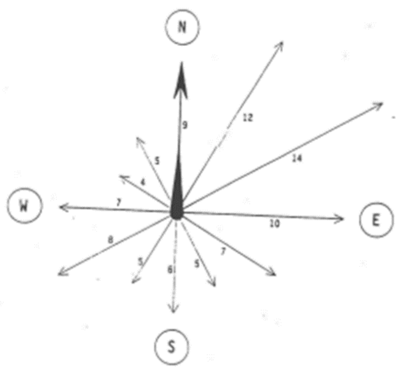


Figure 2: Average Wind Direction (% of Time)

- Other data:

Rainfall (Design):	25 mm/h
	50 mm/day
Snow (Design):	50 kg/m^2
Winterization:	winterization is required
Earthquake:	not applicable

6.4 Utilities and Service Fluids Characteristics/Conditions

Following sections list main utilities and service fluids used within the Oil Refinery.

6.4.1 Water Supply

Potable Water

- Source: from grid
- Type: Potable water
- Operating pressure at grade: 0.80 barg (min)
- Operating temperature: Ambient
- Design pressure: 5.0 barg
- Design temperature: 38 °C

Raw Water

- Source: from grid
- Type: Potable water
- Operating pressure at grade: 0.80 barg (min)
- Operating temperature: Ambient
- Design pressure: 5.0 barg
- Design temperature: Ambient

Plant water

- Source: from storage tank of raw water
- Type: Raw water
- Operating pressure at grade: 3.5 barg
- Operating temperature: Ambient
- Design pressure: 9.0 barg
- Design temperature: 38°C

Demineralised Water

- Type: Treated raw water
- Operating pressure at grade (min): 5.0 Barg
- Design pressure: 9.5 Barg
- Operating temperature: Ambient
- Design temperature: 38°C
- Characteristics:
  - pH 6.5 – 7.0
  - Total Dissolved Solids 0.1 mg/kg (max)
  - Conductance at 25°C 0.15µS (max)

- Iron — 0.01 mg/kg as Fe (max)
- Free CO_2 — 0.01 mg/kg as CO_2 (max)
- Silica — 0.015 mg/kg as SiO_2 (max)

6.4.2 Cooling Water

The study assumed that once –through seawater cooling circulation is used in the older part of the refinery (with maximum capacity of 5000 m^3/h). Units using the seawater cooling system are identified in Base Case report.

For the (more modern) conversion and treatment units, as well as for the additional CO_2 capture facilities, cooling water from a closed loop system with cooling towers will be used. This is to reflect that the refineries are built and expanded in various phases. As the refinery, they are required to meet more stringent environmental regulations to their recent upgrading/revamping projects. Units using the closed loop cooling system are identified in the Base Case Report.

Furthermore, maximum use of air coolers, where applicable, shall be considered as an alternative to the water cooling system.

Primary System: Seawater Cooling

- Source: sea water in once through system
- Type: clear filtered & chlorinated, without suspended solids and organic matter.
- Salinity: 22 g/l
- Supply temperature:
  - average supply temperature (on yearly basis): 12°C
  - max supply temperature (average summer): 14°C
  - min supply temperature (average winter): 9°C
  - max allowed sea water temperature increase: 7°C
- Return temperature:
  - average return temperature: 19°C
  - max return temperature: 21°C
- Design temperature: 50°C
- Operating pressure at Users inlet: 0.9 Barg
  - Max allowable ΔP for Users: 0.5 Barg
  - Design pressure for Users: 4.0 Barg
  - Design pressure for sea water line: 4.0 Barg
- Cleanliness Factor (for steam condenser): 0.9
- Fouling Factor: 0.0002 h °C m^2/kcal

Secondary System: Closed Loop Cooling Water (with Cooling Towers)

Closed loop cooling water system is based mechanical draft cooling system. The operating parameters are as follows:

- Temperature
  - Supply Temperature: 30°C
  - Return Temperature: 40°C
  - Design Temperature: 70°C

- Operating Pressure:
  - Supply Pressure (See Note 1) 5.0 Barg
  - Return Pressure (See Note 1) 2.5 Barg
  - Design Pressure 12.0 Barg
- Fouling Factor(See Note 2): 0.0004 h °C m^2/kcal

Notes:

(1.) Pressure and temperature at unit battery limit measured at grade.
(2.) For shell and tube exchangers only.

6.4.3 Air Cooling System

Inlet temperature of the air to be considered for the design of any air cooling system is based on 25ºC.

6.4.4 Instrument and Plant Air and Nitrogen

Instrument Air

- Operating pressure (See Note 1)
  - normal: 7 Barg
  - minimum: 5 Barg
- Design pressure: 10 Barg
- Operating temperature (max): 40°C
- Design temperature: 70°C
- Dew point @ 7 barg: -30°C

Plant Air

- Operating pressure (See Note 1): 7.5 Barg
- Design pressure: 10 Barg
- Operating temperature (max): 40°C
- Design temperature: 70°C

Nitrogen (Low Pressure)

- Supply pressure (See Note 1): 7 Barg
- Design pressure: 11.5 Barg
- Supply temperature (min): 15°C
- Design temperature: 70°C
- Min Nitrogen content: 99.9 % vol.
- Max. oxygen content: 10 ppm vol.

(1) Supply pressure at process units battery limits

6.4.5 Refinery Process Steam and Condensate – Conditions and Characteristics

Process Steam

Conditions at Steam Generators/Producers								
Service	Pressure, barg (1)				Temperature, °C (1)			
	Max	Norm	Min	Design	Max	Norm	Min	Design
High Pressure	44.5	44.0	42.0	49.5	400	380	350	425
Medium Press.	13.0	13.0	10.5	15.0	320	310	300	350
Low Pressure	5.5	5.0	4.0	7.3	240	220	220	270

Conditions at Process Units Battery Limit								
Service	Pressure, barg (1)				Temperature, °C (1)			
	Max	Norm	Min	Design	Max	Norm	Min	Design
High Pressure	44.5	42.0	40.0	49.5	400	370	340	425
Medium Press.	13.0	12.0	9.5	15.0	320	260	240	350
Low Pressure	5.5	4.5	3.5	7.3	240	190	170	270

(1) Pressure and temperature at unit battery limit.

Fouling factor: 0.0001 m^2 °C h/kcal

The steam conditions listed above shall be used as battery limit supply and exhaust conditions for steam turbines. An allowance of 0.5 bar pressure drop from each supply/exhaust header to the supplied equipment flange shall be assumed.

Process Condensate

Steam condensate will be flashed within the process units whenever possible to recover steam and piped back to the condensate collection header.

The condensate collection header shall have the following characteristics:

- Operating pressure for other Units B.L.: 1 Barg
- Operating temperature: 94 °C
- Design pressure: 15 Barg
- Design temperature: 250 °C

6.5 Chemicals

Typical chemicals used within the plant include the following:

- Chemical Packages Used for Treating Boiler Feed Water
  - Oxygen scavenger (Nalco Elimin-OX 100%, or equivalent),
  - Phosphate injection (50% Na_2HPO_4 in water solution), and
  - pH control injection (Morpholine 100%, or equivalent)

  Design Pressure: atmospheric pressure plus full tank of liquid solution
  Design Temperature: 80°C

- Chemical Packages Used within the Plant

  - Caustic Soda

    Concentrated NaOH (50% by wt.) will be supplied and diluted with demineralized water before distribution to users.

    Design Parameters

▪ Supply temperature	Ambient
▪ Design temperature	80°C
▪ Supply pressure (at grade) at unit BL	3.5 Barg
▪ Design pressure	9.0 Barg
▪ NaOH concentration	20% wt.

  - Hydrochloric Acid

    Concentrated HCl (20% by wt.) will be supplied and diluted with demineralized water to users if necessary.

    Design Parameters

▪ Supply temperature	Ambient
▪ Design temperature	80°C
▪ Supply pressure (at grade) at unit BL	2.5 Barg
▪ Design pressure	5.0 Barg
▪ HCl concentration	20% wt.

6.6 Environment Limits

The environmental limits set for the different cases are outlined in this section of the report.

6.6.1 Gaseous emissions

This study assumed that the EU Industrial Emissions Directive (IED) 2010/75/EU will be enforced.

The emissions limits to be employed to the specific unit processes are based on the specification presented in this section of the report. Additionally, any large combustion plants must meet the specific requirements for existing plants set out in the BREF BAT Document for the Refining of Mineral Oil and Gas and Chapter III and Annex V of IED.

The overall gaseous emissions from the plant do not exceed the following limits:

1. Any large combustion plants firing any commercial solid or liquid fuels with greater than 50MWth (covering all COGEN, boilers, fired heaters, and others; but excluding gas turbine, gas engine, combustion plants using distillation or conversion residues as fuel or part of the multi-fuel, catalyst regeneration from catalytic crackers and emissions from conversion of H_2S to sulfur).

   a. SOx (as SO_2) - mg/Nm^3

Thermal Plant	Solid Fuel	Liquid Fuel
50-100	400	350
100-300	200	200
>300	150	150

   b. NOx (as NO_2) - mg/Nm^3

Thermal Plant	Solid Fuel	Liquid Fuel
50-100	300	450
100-300	200	150
>300	150	100

   c. CO - mg/Nm^3

Thermal Plant	Solid Fuel	Liquid Fuel
50-100	100	100
100-300	100	100
>300	100	100

   d. Particulate Matters (as dust) - mg/Nm^3

Thermal Plant	Solid Fuel	Liquid Fuel
50-100	20	20
100-300	20	20
>300	10	10

2. Any large combustion plant firing gaseous fuels with greater than 50MWth (except for gas turbine and gas engine)

    a. SOx (as SO_2) – mg/Nm^3
        - General cases (typical values for NG) 35 mg/Nm^3
        - For liquefied gas 5 mg/Nm^3
        - For syngas from gasification of refinery residues 800 mg/Nm^3

    b. NOx (as NO_2) - mg/Nm^3
        - General cases (typical values for NG) 200 mg/Nm^3
        - For commercial NG 100 mg/Nm^3
        - For refinery off-gases 300 mg/Nm^3
        - For syngas from gasification of refinery residues 200 mg/Nm^3

    c. CO - mg/Nm^3
        - General cases (typical values for NG) 100 mg/Nm^3
        - For liquefied gas 5 mg/Nm^3

    d. Particulate Matters - mg/Nm^3
        - General cases 5 mg/Nm^3

3. Any combustion plant firing gaseous or liquid fuels in gas turbine and gas engine.

    a. NOx (as NO_2) - mg/Nm^3
        - Gas turbine (including CCGT) using liquid fuels 90 mg/Nm^3
        - Gas turbine (including CCGT) using commercial NG 50 mg/Nm^3
        - Gas turbine (including CCGT) using refinery off-gases 120 mg/Nm^3
        - Gas engine 100 mg/Nm^3

    b. CO - mg/Nm^3
        - Gas turbine (including CCGT) 100 mg/Nm^3
        - Gas engine 100 mg/Nm^3

4. Average emissions limit values specific to any combustion plants firing multi fuels produced or used within the refineries and FCC.

    a. Fired Heaters, boiler, and others specifically using distillation or conversion residues - alone or together with other fuels (i.e. multi-fuel combustion plants within refineries).
        - SOx (as SO_2): 1000 mg/Nm^3 as average emission limit values across combustion units
        - NOx (as NO_2): 450 mg/Nm^3
        - CO: 100 mg/Nm^3
        - Particulate Matter (as dust): 50 mg/Nm^3

    b. Fluid Catalytic Cracker (FCC) Regeneration Units (at full burn conditions)
        - SOx (as SO_2): for full combustion mode 800 mg/Nm^3
        - SOx (as SO_2): for partial combustion mode 1200 mg/Nm^3
        - NOx (as NO_2): for full combustion mode 300 mg/Nm^3
        - NOx (as NO_2): for partial combustion mode 400 mg/Nm^3

- CO: 100 mg/Nm^3
- Particulate Matter: 50 mg/Nm^3

Notes:

- Unless specified, all emission expressed in mg/Nm^3 are @ 3% O_2, dry basis for liquid and gaseous fuel (except for gas turbine and gas engine); @ 6% O_2 dry basis for solid fuels; and @15% O_2 dry basis for gas turbine and gas engine.

- Article 29 of IED covers any emissions from two or more combustion plants that are discharged in a common stacks.

- Article 40 and Part 1 and 7 of Annex V of IED covers any emissions from multi-fuel combustion plant.

6.6.2 Liquid Effluent

The liquid effluent of the oil refinery and the additional effluent from the CO2 capture facilities are sent to the waste water treatment plant.

Characteristics of waste water discharged from the plant comply with the standard limits included in the EU directives currently in force (including the IED).

Waste solvents and other chemicals used by the CO2 capture facilities are to be processed by specialize companies outside the B.L..

6.6.3 Solid Wastes

Spent catalysts will be in their oxidized/inert state and, as such, non-hazardous. They should be handled in accordance with the catalyst vendor’s instructions and the owner’s established procedure. Reformer catalyst contains nickel, which can often be recovered. The other spent catalyst would normally be disposed in a landfill.

6.6.4 Noise

All the equipment of the plant are designed to obtain a sound pressure level of 85 dB(A) at 1 meter from the equipment.

6.7 Units of Measurement

The units of measurement are in SI or Metric units.

Table 11: Preferred units of measurement

Quantity	Units for general application
BASE UNITS	
Length	**m** mm (1) (2)
Mass	**kg** t
Mole	**kmol** mol
Temperature	**°C** K
Area	**m^2** mm^2
Volume	**m^3** l (litre)
Time	**s** **h** d y
Velocity	**m/s**
Molecular Weight	kg/kmol
Frequency	**Hz** kHz MHz
Concentration	Vol%, wt%, ppmw
Pipe Size	Inches (1)
FLOW (MASS OR VOLUME PER UNIT TIME)	
Mass Flow	**kg/h** kg/s t/d kt/y
Molar Flow	**kmol/h** kmol/s
Volumetric Flow	**m^3/h** l/s
Normal Volumetric Gas Flow	Nm^3/h (4)
Standard Volumetric Liquid Flow	Sm^3/h (3) BPSD
MASS PER UNIT VOLUME (DENSITY)	
Density / Flowing Density	**kg/m^3** / kg/m^3 at flowing conditions
Liquid Specific Gravity	Density @15.5°C/Density of Water @ 4.4°C
MECHANIC	
Pressure (Absolute)	bara
Pressure (Vacuum)	mmHg
Pressure (Heaters Draft)	mmH_2O
Pressure (Gauge)	barg
Pressure Drop	bar mbar
Energy, Work	MJ kJ
Rotational Frequency	rpm
Dynamic Viscosity	**cP** (centipoise) Pa s
Kinematic Viscosity	**cSt** (centistokes) m^2/s
Surface Tension	**dynes/cm** mN/m

Quantity	Units for general application
HEAT	
Heat Quantity	**kcal** kJ
Heat Flow Rate	**kcal/h** kW MW kJ/h
Heat Flux	**kcal/m² h** kW/m² kJ/m² h
Thermal Conductivity	**kcal/h m °C** W/m °C
Coefficient of Heat Transfer	**kcal/h m² °C** W/m² °C
Thermal Resistivity / Fouling factor	**m² °C h/kcal** m² °C/W
Specific Heat Capacity	**kcal/kg °C** kJ/kg °C
Specific Energy / Enthalpy, Latent Heat	**kcal/kg** kJ/kg
Calorific Value (mass basis)	**kcal/kg** kJ/kg
Calorific Value (volume basis)	**kcal/m³ kcal/Nm³** kJ/m³ kJ/Nm³
ELECTRICITY AND MAGNETISM	
Electric Current	kA A mA
Electric Potential	kV V mV µV
Electrical conductivity	µS/cm S/m
Power (Active)	MW kW W
Electrical Energy	**kWh** MWh kJ J
Frequency	**Hz** kHz MHz

Notes:

1. *Use mm for equipment dimensions and corrosion allowance.*
2. *The inch-pound units shall be used for all piping system sizing & rating.*
3. *Standard conditions are at 15.5°C and 1.01325 Bara.*
4. *Normal conditions are at 0°C and 1.01325 Bara.*
5. *Preferred units are in bold.*

6.8 Codes and standards

The design of the process and utility units are in general accordance with the main International and EU Standard Codes (such as API, ASME, ANSI, IEC, ISA, NFPA, PED and other Euro Norms).

7 UNIT AND EQUIPMENT NUMBERING

7.1 Unit Numbering

The assigned numbers of each Unit Process are presented in Table 12.

Table 12: Process, Utility, and Offsite Units Number

Process Units		
Unit No.	**Abbreviation name**	**Extended Name**
0100	CDU	Crude Distillation Unit
0200	SGP	Saturated Gas Plant
0250	LSW	LPG Sweetening
0280	KSW	Kerosene Sweetening
0300	NHT	Naphtha Hydrotreater
0350	NSU	Naphtha Splitter Unit
0400	ISO	Isomerization
0500	CRF	Catalytic Reforming
0550	RSU	Reformate Splitter Unit
0600	KHT	Kero HDS
0700	HDS	Gasoil HDS
0800	VHT	Vacuum Gasoil Hydrotreating
0900	HCK	Vacuum Gasoil Hydrocracking
1000	FCC	Fluid Catalytic Cracking
1050	PTU	FCC Gasoline Post-Treatment Unit
1100	VDU	Vacuum Distillation
1200	SMR	Steam Reforming
1300	SDA	Solvent Deasphalting
1400	DCU	Delayed Coking
1500	VBU	Visbreaking Unit
1700	PSA	Pressure Swing Adsorption
Auxiliary Units		
2000	ARU	Amine Washing and Regeneration
2100	SWS	Sour Water Stripper
2200	SRU	Sulphur Recovery & Tail Gas Treatment
2300	WWT	Waste Water Treatment / API Separator
Power Units		
2500	CPP	Power Plant
Utility Units		
3100	CWS	Cooling Water System
3200	SRW	Service & Potable Water Systems
3300	DEW	Demineralized Water System
3400	BFW	Boiler Feed Water System
3500	FFW	Fire Water and Fire Fighting System
3600	STS	Steam System
3700	CON	Condensate Recovery System
3800	AIR	Plant and Instrument Air System
3900	FGS	Fuel Gas System

Process Units		
4000	FOS	Fuel Oil System
4100	NGU	Nitrogen System
4200	CHE	Chemical Systems
Off-Sites Units		
4600	FLA	Flare System
4700	TAN	Tankage and Pumping System
4800	INT	Interconnecting System
5000	SWI	Sea Water Intake
5100	COH	Coke Handling System
5200	SEW	Sewer Systems
5300	TLA	Trucks Loading Area
	BUI	Buildings, DCS, S/S

7.2 Equipment Numbering

Equipment are numbered in accordance to the following system:

Basic format: AA-UUXX

where:

1. AA: No. 2 max. uppercase letters, in accordance with table 5.2.1, identifying the type of equipment,
2. UU: Unit Number (two digits, in accordance with table 5.1.1)
3. XX: Sequential number (starting from 01)

Parallel or series equipment will have the same number but with the "A" or "B" added at the end as a suffix, e.g. P-3010 A.

The assigned numbers of each major equipment are presented in Table 13.

Table 13: Equipment Type List

Equipment Code and Description	
Primary Equipment (1)	
A	Miscellaneous
C	Compressors, Blowers
CO	Concrete Basin, Pits, Sumps
CT	Cooling Towers
D	Pressure vessels
DR	Dryers
DS	Desuperheaters
E	Heat Exchangers (S&T, Double Pipe, Kettles)
EA	Air Coolers
F	Filters
FL	Flares
GT	Gas Turbines

Equipment Code and Description	
H	Furnaces
J	Ejectors and Eductors
LA	Loading Arms
M	Mixers, Agitators
P	Pumps
PK	Packages
R	Reactors
SG	Boilers (Fired Equipment)
ST	Steam Turbines
T	Towers
TK	Tanks
TU	Underground tanks (LPG bullets)

Equipment Code and Description	
Ancillary Equipment	
EG	Electrical Generators
FA	Flame Arrestors
ME	Air Coolers Motor
MF	Fan's Electric Motor
MK	Compressor's Electric Motor
MM	Mixer's or Agitator's Electric Motor
MP	Pump's Electric Motor
SC	Sample Connections
SL	Silencers
TB	Fan's/Blower's Turbine Driven
TC	Compressor's Turbine Driven
TP	Pump's Turbine Driven
TR	Steam Traps

1. *Only Primary Equipment will be shown on PFDs.*

8 GENERAL DESIGN CRITERIA - EQUIPMENT

The following design criteria are intended to be used for the design of new equipment and systems in the CO_2 capture units.

They reflect the state-of-the-art, general criteria normally adopted for the design of refinery process plants.

Exceptions are possible, but they shall be minimized and justified.

8.1 Design Pressure

The design pressure is the max. and/or min. pressure for which the mechanical calculations are performed.

The design criteria presented below covers the following range of operating pressures:

- 0 to 12.0 Barg — max. norm. operating pressure + 1.8 bar (*)
- 12.0 to 21.1 Barg — max. norm. operating pressure × 1.15
- 21.1 to 31.6 Barg — max. norm. operating pressure + 3.2 bar
- 31.6 to 70.0 Barg — max. norm. operating pressure × 1.10
- > 70 barg — special design case

(*) *Minimum design pressure for equipment protected by a pressure relief valves discharging to flare shall not be lower than 7.0 Barg.*

Below summarises the criteria to be followed:

- Design pressure defined in accordance with the above criteria does not include liquid static head, which will be added by the Vessel Design Group, based on high liquid level.

- Maximum normal operating pressure used for calculation of design pressure shall not be lower than maximum cold liquid vapour pressure at ambient temperature.

- Design pressure for storage vessels for LPG and liquids with boiling point lower than 45°C shall not be less than vapour pressure at 50°C.

- Full vacuum design conditions shall be specified for equipment normally operating under vacuum conditions or those that are subject to evacuation during start up, shut down, and/or regeneration.

- Full vacuum shall also be specified for:

  - Vessels and heat exchangers which handle fluids having a vapour pressure lower than atmospheric pressure at minimum ambient temperature, normally operate liquid full and that can be blocked in and cooled down

  - Fractionating columns and associated equipment that can undergo a vacuum condition through loss of heat input.

- Steam turbine condenser

  All vessels not in vacuum service but subject to steam shall be designed for half-vacuum at maximum operating steam temperature.

- Equipment in pumped (centrifugal pumps) circuits:

  - If a control valve or block valve is installed downstream of the equipment, the design pressure shall be calculated as the design pressure of equipment where pump is taking suction + maximum suction static head + an estimated pump shut off head equal to 120% of the centrifugal pump rated head, in case of electric motor driver.

  - In case of a steam turbine driven centrifugal pump, the design pressure shall be calculated as:
    - maximum suction pressure + an estimated pump shut-off head equal to 135% of the centrifugal pump rated head in case of governor NEMA Class A
    - maximum suction pressure + an estimated pump shut-off head equal to 121% of the centrifugal pump rated head in case of governor NEMA Class C or D

  - For equipment protected by a downstream installed safety valve the design pressure shall be calculated as the design pressure of the equipment where the safety valve is installed + 120% the estimated pressure drop from the affected equipment and the equipment where the safety valve is installed + static head (if any).

  - In general, the suction side of pumps including the suction isolation valves shall be designed for the discharge design conditions.

- Heat exchangers shall be designed by following the “10/13 rule” in accordance with the latest edition of ASME VIII Div.1. This means to set a design pressure of the lower pressure side of a heat exchanger not lower than 77% of the design pressure of the higher pressure side. This design rule allows to protect the equipment against tube rupture without installing a PSV. The design pressure set following the “10/13 rule” will be extended also to inlet and outlet piping connected to the lower pressure side of the heat exchanger including the isolation valves.

8.2 Design Temperature

The design temperature is the maximum and/or minimum temperature value for which the mechanical calculation of the equipment shall be performed.

The following summarizes the criteria to be followed to set the minimum design temperature:

- Maximum normal operating temperature + 28°C.

- When increased operating flexibility is required or future operating conditions are expected, the above design margin can be higher.

- Maximum temperature during start up, shut down, drying, purging, catalyst regeneration or during upset conditions excluding fire (e.g. Reactor runaway, loss of cooling, etc.)

- Flare blow down vessels shall be designed for –29°C/343°C.

- Minimum Design Metal Temperature (MDMT) shall be specified. It shall be the lowest among the following values:
    - The minimum ambient temperature,
    - The lowest temperature expected in service,
    - The minimum temperature, which can be achieved during upset operating conditions.

8.3 Equipment Design Life and Corrosion Allowance

Unless otherwise dictated by process reasons, the corrosion allowance and design life will be specified in accordance with the following guidelines:

- <u>Thick-walled Reactors and Vessel</u>
  Corrosion allowance for 20 yrs design life.

- <u>Column & Vessel Carbon Steel and Alloy Construction (including non-removable internal)</u>
  Corrosion allowance for 20 yrs design life.

- <u>Heat Exchanger</u>

  Shell of Carbon Steel and Alloy Construction (including non-removable internal)
  Corrosion allowance for 20 yrs design life.

  Bundle of Stainless Steel Construction
  Corrosion allowance for 10 yrs design life.

  Bundle of Carbon Steel and Alloy Steel Construction
  Corrosion allowance for 5 yrs design life.

- <u>Furnace Tubes</u>
  Corrosion allowance for 10 yrs design life.

- <u>Process Piping</u>

  Carbon Steel Construction
  Corrosion allowance for 10 yrs design life.

  Alloy Steel Construction
  Corrosion allowance for 15 yrs design life.

Stainless Steel Construction
Corrosion allowance for 15 yrs design life.

- Other Equipment and Removable Vessel Internals

Carbon Steel Construction
Corrosion allowance for 10 yrs design life.

Alloy Steel Construction
Corrosion allowance for 15 yrs design life.

Stainless Steel Construction
Corrosion allowance for 15 yrs design life.

8.4 Design Oversizing Factors

The criteria of design oversizing factors to be used to determine the dimensions and/or rating capacity of equipment and machinery are listed herein below.

8.4.1 Fired Heaters

Unless otherwise dictated for process reasons, 10% overdesign margin shall be considered on duty (the inlet temperature shall be adjusted and specified accordingly).

8.4.2 Drums

No oversizing is considered. Suitable hold-up times are considered according to the services the drums are specified for.

The following minimum liquid surge time shall be provided between low and high liquid level in new drums, unless otherwise dictated by process reason:

Service	Surge Time, min
Drums feeding other equipment for further processing	15
Feedstock surge drum	20
Overhead receivers	Note 1
Reboiling by heater	Note 2
Reboiling by thermosyphon	Note 3
Product to storage	2
Flow to sewer or drain	1
Water pot	2

Note 1: *5 min. hold up shall be considered with respect to the reflux flow rate or 2 min. with respect to the net product flow rate whichever is the greater.*
Note 2: *15 min. on feed to fired heater.*
Note 3: *10 to 30 seconds on feed to thermosyphon reboiler.*

The same sizing rules shall be applied also to hold-up capacity of columns.

8.4.3 Columns

Unless otherwise dictated for process reason, new columns shall be sized in order to obtain a percent flooding not higher than 75% based on the maximum normal loading rate.

The above should not apply to pump-around sections, where higher flooding is acceptable.

8.4.4 Pumps

Unless otherwise dictated for process reasons, the rated pump capacity, for new pumps, shall be the maximum normal flow-rate multiplied by the following factors:

Capacity/Control	Factor
Pumps capacity under flow control	1.10
Pumps capacity under level control or heat removal	1.20

8.4.5 Compressors

Unless otherwise dictated for process reasons, design margins, for new compressors, shall be 1.10.

8.4.6 Drivers

Motors shall have power ratings, including the service factor (if any), at least equal to the percentages of power at pump rated conditions given in the table below:

Motor Nameplate Rating	Percentage
< 22 kW	125
≥ 22 but < 55 kW	115
≥ 55 kW	110

Steam turbine drivers shall be sized to deliver continuously 110% of the maximum power required for the purchaser's specified conditions, while operating at corresponding speed with specified steam conditions.

8.4.7 Heat Exchangers

Unless otherwise dictated for process reasons, a design margin of 10% shall be specified on required surface for new coolers/condensers (including air), and reboilers.

The overdesign on pump-around exchangers will be evaluated on a case by case basis, considering the specific service and temperature approach.

In addition to the above requirements, for heat recovery systems (i.e. feed/effluent and feed/bottom) the following overdesign criteria shall also be verified:

- Effluent cooler and feed heater: 10% of cooler or heater duty or 5% of feed/effluent duty, whichever is greater;
- Reboiler: 5% of feed/bottom duty or 10% of reboiler duty, whichever is greater;

- Bottom cooler: 10% of cooler duty or 5% of feed/bottom duty, whichever is greater.

8.4.8 Control Valves

Unless otherwise dictated for process reasons, the pressure drop of control valves, not in gravity flow, shall be the greater of:

- 0.7 bar at maximum flow, or
- 20% of circuit frictional pressure drop at normal operating flow or
- 10% of operating pressure (Op. Press. ≤ 15.0 barg) or
- 1.5 bar (15.0 barg < Op. Press. ≤ 30.0 barg), or
- 5% of operating pressure (Op. Press. > 30.0 barg).

For control valves in systems such as reflux or recirculation loops, pressure drop shall be the greater of:

- 10% of pumps differential pressure, or
- 30% of circuit friction loss, or
- 0.5 bar.

The flow rate considered in control valve sizing is the max. normal operating flow rate.

9 SOFTWARE TOOLS

For the design of the plant for the different study cases, four software tools have been mainly used, as applicable:

- Aspen Plus v8.2/ Aspen HYSYS v8.6: amine sweetening process (MEA, MDEA) for CO_2 removal.

- Aspen HYSYS v8.6 (by AspenTech): Process Simulator used for H_2 Plant modelling and CO_2 compression and drying, as well as for modelling of other process units (e.g. Crude Distillation and Vacuum Distillation).

- Aspen Economic Analyzer : cost estimation

- Haverly GRTMPS v5.0: Linear Programming software, used to produce the refinery balances.

Evaluating the Cost of Retrofitting CO_2 Capture in an Integrated Oil Refinery

Reference Document 2: Cost and Economic Assumptions

Responsible Organization:
IEA Greenhouse Gas R&D Programme
Cheltenham, UK

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Evaluating the Cost of Retrofitting CO_2 Capture in an Integrated Oil Refinery

Task 2 - Part II: Reference Document – Economic Assumptions

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1. Introduction

This report presents the key criteria and assumptions used in the assessment of the cost of the oil refining without CCS and of the additional cost of implementing CO_2 capture and compression. This includes the key assumptions for calculation of the total plant cost (TPC) and total capital requirement (TCR), as well as operating costs and Key Performance Indicators (KPIs).

2. Evaluation of the costs of refinery without capture and implementation of CO_2 capture

In the power generation industry, the CO_2 avoided cost is defined as the difference between the levelised cost of electricity (LCOE) with and without CCS divided by the difference in nominal climate impact of electricity without and with CCS as shown below. In this case, the CO_2 avoided needs to be calculated based on both the power plant with and without CCS as the plant net power output or the plant fuel in-take is modified when CCS is included.

$$CO_2 \text{ avoided cost} = \frac{(\mathrm{LCOE})_{\mathrm{CCS}} - (\mathrm{LCOE})_{\mathrm{ref}}}{(\mathrm{t_{CO2}/MWh})_{\mathrm{ref}} - (\mathrm{t_{CO2}/MWh})_{\mathrm{CCS}}}$$

where

- $(\mathrm{LCOE})_{\mathrm{CCS}}$ is the levelised cost of electricity of produced by the plant with CCS [€/MWh]
- $(\mathrm{LCOE})_{\mathrm{ref}}$ is the levelised cost of electricity of the reference plant without CCS [€/MWh]
- $(\mathrm{t_{CO2}/MWh})_{\mathrm{CCS}}$ is the CO_2 emission rate to the atmosphere of the plant with CCS [$\mathrm{t_{CO2}/MWh}$]
- $(\mathrm{t_{CO2}/MWh})_{\mathrm{ref}}$ is the CO_2 emission rate to the atmosphere of the reference plant without CCS [$\mathrm{t_{CO2}/MWh}$]

However in the case of CCS from industry (refinery, cement, steel, etc.), if the implementation of CCS does not modify the product outputs of the plant and the additional cost linked to CCS implementation can reported separately from the main plant, the above equation can be simplified as follow:

$$CO_2 \text{ avoided cost} = \frac{\text{Annualized CCS CAPEX} + \text{Annualized CCS OPEX}}{\text{Annual amount of } CO_2 \text{ avoided}}$$

In the ReCap project, the refinery input (number of barrels of crude and crude mix) and output (product quantity and mix) are assumed to remain identical when CO_2 capture is added.The cost of the refinery is reported without CCS and the cost of CO_2 capture and conditioning is calculated solely based on the additional cost generated by the implementation of the CO_2 capture and conditioning.

2.1 Cost of the refinery without CCS

The cost of the refinery without CCS is reported in absolute CAPEX and OPEX values (M$) as well as in a normalised refinery processing cost. Although crude and product prices are necessary to establish the optimum product yield of the four refinery Base Cases, it is worth noting that the prices of crudes and others refinery feedstocks are not necessary to calculate the refinery processing cost.

$$\text{Refinery processing cost } (\$/\text{bbl}_{\text{crude}}) = \frac{\text{Annualized refinery CAPEX} + \text{Annual refinery OPEX}}{\text{Annual amount of crude processed}}$$

where the annualized CAPEX is calculated based in order to ensure a constant repayment of the investment over the project duration. Based on the discount rate (8%) and the project economic duration (25 years), the annualized CAPEX is defined as 8.67% of the total capital requirement.

2.2 Cost of implementing the CO_2 capture and conditioning

The cost of CO_2 capture and conditioning is calculated based on the *additional* cost for a given refinery with unchanged production. This additional cost is connected to the implementation of CO_2 capture (i.e. the costs of CO_2 capture, conditioning, compression and additional CHP), as well as refinery modifications (e.g. moving of tanks) and interconnections.

While investment and operating cost are reported, the cost of CO_2 capture and conditioning is defined as the sum of the annualized investment and the annual operating cost divided by the annual amount of CO_2 avoided.

$$\text{Cost of CO}_2\text{ capture and conditioning} = \frac{\text{Annualized CAPEX} + \text{Annual OPEX}}{\text{Annual amount of CO}_2\text{ avoided}}$$

where the annualized CAPEX is calculated based in order to ensure a constant repayment of the investment over the project duration. Based on the discount rate (8%) and the project economic duration (25 years), the annualized CAPEX is defined as 8.67% of the total capital requirement.

3. Financial assumptions

- The “Reference” Integrated Oil Refinery is assumed to be located along the Coastal Region of The Netherlands.
- All cost are reported in US$ (2015Q4 basis). When necessary, updates of cost are performed using indexes such as the CEPCI and currency are converted based on a 1.1078 $/€ exchange rate.
- Project evaluations are performed based on an economic lifetime of 25 years.
- The discount rate and cost of capital assumed to be both equal to 8%.
- There is no major recurring capital expenditure expected for the refinery. It is assumed that major CAPEX items needed are included in the annual maintenance cost.
- Decommissioning and remediation of the land at the end of the project is excluded. It is assumed that the residual value of the plant and the selling of the land should cover any cost related to the decommissioning of the plant.
- Inflation assumptions are not included. No allowance for escalation of fuel, raw materials, labour and other cost relative to each other is taken into account.

- Depreciation is not included. The calculation of cost Key Performance Indicators are calculated based on an EBITDA basis (Earnings Before Interest, Taxes, Depreciation and Amortisation).

4. Total Capital Requirements

The Total Capital Requirement (TCR) includes:

- Total Plant Cost (TPC)
- Spare parts cost
- Start-up costs
- Owner's costs.
- Interest during construction
- Working capital

The estimate accuracy is in the range of +35% / -15% (AACE Class IV).

4.1 Total Plant Cost (TPC)

The TPC (also reported as total investment cost) of the main refinery processes, the hydrogen production unit and the power and steam generation plant are based on the estimates reported for a typical Turnkey Plant.

The TPC of the CO_2 capture plant and associated modification to the refinery is estimated in more detail. This consists of the total installed cost of the plant including contingencies. The TPC is broken down into the main process units, and for each unit, the cost is reported according to the following items:

- Direct materials cost
- Construction cost
- Other costs
- EPC services
- Contingency

Meanwhile, the direct material costs for the CO_2 capture plant and refinery modifications are evaluated based on a Bottom Up approach relying on detail equipment sizing. In this approach, all material costs are assessed based on cost estimation software, AMEC Foster Wheeler and SINTEF Energy Research internal database, vendors' quotation, etc. The construction cost, other cost, EPC services are estimated using an internal database and general practice in the oil refining industry.

Finally, the project contingencies, meant to include a 50%/50% probability of cost over-run/under-run, are assumed to represent a percentage of direct material cost, construction cost, other costs and EPC services. For the refinery Base Cases, the project contingency is 10%, and for the implementation of CO_2 capture, the contingency is 15%.

4.2 Spare Parts, Start-up Cost, Interest during construction, Owner's cost

The cost of spare parts, start-up, interest during construction, Owner's cost are assessed using the standard IEAGHG practices.

- Spare parts cost are assumed to represent 0.5% of TPC
- Start-up costs consist of:

- 2% of TPC, to cover modifications to equipment that will be needed to bring the unit up to full capacity.
  - 25% of the full capacity fuel cost for one month, to cover inefficient operation that occurs during the start-up period
  - Three months of operating and maintenance labour costs, to include training
  - One month of catalysts, chemicals and waste disposal costs.
- Owner's costs are assumed to represent 7% of TPC. Owner's costs cover the costs of feasibility studies, surveys, land purchase, construction or improvement to roads and railways, water supply etc. beyond the site boundary, owner's engineering staff costs, permitting and legal fees, arranging financing and other miscellaneous costs.
- Interest during construction is based on a construction period of 3 years with a cost allocation of 20/50/30 over this period
- Working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). It is assumed that the cost of these materials shall be recovered at the end of the plant life.

5. Annual operating and maintenance cost

5.1 Maintenance, Insurance and labour costs (Fixed O&M Cost)

The fixed operating costs which covers labour, maintenance and insurances are assessed as follow:

- *Labour costs:* Labour costs include operating labour, administrative and support labour and are calculated based on the total number of employees and an annual average salary of 80 000$/y. The number of personnel engaged is estimated for each cases with the consideration of a 5 shift work pattern.
- *Insurance and local property taxes:* The total annual cost of insurance, local property taxes and miscellaneous regulatory and overhead fees is to be a total of 0.5% of TPC.
- *Maintenance cost:* Maintenance costs include cost of preventive maintenance, corrective maintenance (repair and replacement of failed components). In this study the following assumption are used in estimating the annual maintenance cost:
  - Whole Refinery Major Processes 3.0% of TPC
  - Hydrogen Production Unit 1.5% of TPC
  - Power Plant 2.5% of TPC
  - Flue gas desulfurization unit 2.0% of TPC
  - Utilities and Off-sites Unit 1.0% of TPC
  - CO_2 Capture Plant 2.0% of TPC

5.2 Energy, chemicals and consumables (Variable O&M Cost)

The variable operating costs include costs associated with the consumption of natural gas, chemicals and catalyst, raw process water (make-up), solvents (for CO_2 capture plant), waste Disposal (for CO_2 capture plant). The costs are evaluated based on the assessed utilities and make-up consumption combined with the utilities costs given in Table 1.

Table 1: Utility cost

Utility	Cost
Natural Gas [$/GJ]	6.6
Raw process water make-up [$/m^3]	0.1
MEA make-up [$/t]	2000
MEA sludge disposal [$/t]	225
Calcium carbonate cost [$/t]	44
Molecular sieve adsorbent [$/t]	7 200

5.3 Potential revenue for the CCS section

As the aim of the study is to identify the cost of retrofitting CCS on refinery, no carbon tax or quota is considered in the calculation of the cost of CO_2 capture and compression. However, in some cases, excess electricity may be produced by the additional CHP plant installed to supply heat and power to the CO_2 capture and compression. In such cases, this excess electricity is valued considering an electricity price of 74$/MWh.

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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