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FIRST DATA /
REMARKS AND QUESTIONS ON

DRAFT BACKGROUNDDOCUMENT
"PETROLEUM REFINERIES for SO_2, NO_X and TSP (version 25/02/2004)"

[the red text shows the paragraphs of the draft background document to which the Belgian data and remarks refer]
[costs, application rates and applicabilities of the abatement measures proposed in draft background document are not yet discussed in note below]

DRAFT BACKGROUND DOCUMENT (version 25/02/2004)

2.2 Combustion in refinery: definition of reference installation

Two reference combustion installations have been defined in the background document:
- combustion unit on heavy fuel (reference code 01)
- combustion unit on (natural) gas (reference code 02)

A recent study on the reduction potential of air emissions in the Belgian refineries classified our refinery combustion installations into 3 main categories (using similar cost per emission reduced of reduction measures as criteria):
- combustion units (boilers / furnaces) with gas burners
- combustion units (boilers / furnaces) with oil burners
- combustion units (boilers / furnaces) with dual burners

For dual burners different measures or measures with different costs can be identified than for gas and/or oil burners (e.g. fuel switch / installation of low-NOX burners). Therefore - if information is available -the use of a third reference installation (code 03) seems preferable.

No distinction is made between new and existing installations: existing steam boilers in refineries will - more and more - be replaced by new gas turbine installations (CHP). These installations are treated in the background document on combustion. Remains the question how to consider new furnaces in the refinery sector. Together with existing installations under reference codes 01 and 02? As it is treated at the moment in the RAINS model? Or should new furnace installations (with lower emission characteristics and for which measures with higher removal efficiencies and with different costs are applicable) be considered separately (retrofit is more expensive)?

2.3.1 Combustion in refinery: PM emissions

The draft background document does not consider dust abatement techniques. This raises following questions:
1) compliance with LCP directive (elv's for dust) ?
2) compliance with IPPC directive (BREF refineries) ?
3) indirect impact of NO_X and SO_2 emission reduction measures on PM: how will this be considered ?

1) Compliance with LCP directive?
Starting from 1 January 2008 the LCP directive imposes a dust emission limit value of 50 mg/Nm³ for existing combustion plants on liquid fuel (100 mg/Nm³ in case of higher ash content in fuel). In stead of applying limit values a national emission reduction plan achieving equivalent reductions may be used. Belgium choose to

impose emission limit values, also for existing combustion plants in refineries. A limit value of 50 mg/Nm³ corresponds to about 15 g/GJ. To achieve this value reduction measures are necessary. The current average TSP emission factor for fuel combustion installations in Belgian refineries (code 01) amounts to about 55 g/GJ (200 mg/Nm³).

2) Compliance with IPPC directive?
According to the BREF on refineries the following measures can be considered as BAT to reduce PM emissions from liquid firing:

- (reducing the fuel consumption → to be considered through energy projections)
- maximising the use of gas and low ash content liquid fuels
- steam atomisation on the liquid fuels
- ESP or filters for furnaces and boilers on heavy fuel

Only fuel switch to gas is considered in the background document as abatement measure (to reduce emissions of heavy fuel firing).

Note: at the moment fuel switch as measure cannot be introduced in the RAINS model, not without changing the structure of the model. Fuel switch measures can only be taken into account indirectly, through modifying energy projections. It is not clear how EGTEI wants to proceed with fuel switch measures.

3) If no dust abatement techniques are considered for refinery boilers and furnaces, how will the indirect impact of NO_X and SO_2 emission reduction measures (e.g. wet scrubbers / SCR on heavy fuel firing needs to be combined with a dust removal technique) on the PM emissions be taken into account?

The total PM emissions of the combustion installations (boilers, furnaces, CHP) of the Belgian refineries:

- year 1990: 823 ton
- year 1995: 1282 ton
- year 2000: 1016 ton

2.3.2 Combustion in refinery: NO_X emissions

The background document considers following abatement measures:

- Low NO_X burner (abatement efficiency = 30 / 50 %)
- SNCR (abatement efficiency = 60 %)
- SCR (abatement efficiency = 85 %)

According to the BREF information and to other sources higher abatement efficiencies are possible with low NOX burners in new combustion installations (see remark on 2.2 'definition of reference installation') .
The BREF on refineries considers in addition flue gas circulation, reburning techniques and fuel switch as possible BAT's (in suitable combination with above techniques).

Table 2.3 in the background document assumes for gas fired combustion installations (natural gas and refinery gas) an uncontrolled NO_X emission factor of 200 mg/Nm³ (54 g/GJ). This is low compared to the current RAINS default value (70 g/GJ) and compared to the ELV of the LCP directive (existing installations on gas for 50 to 500 MWth: 300 mg/Nm³). Current measured values of uncontrolled NO_X emissions of gas fired refinery combustion plants in Belgium mostly range between 300 and 500 mg/Nm³.
For liquid fuel fired combustion installations an uncontrolled NO_X emission factor of 600 mg/Nm³ is proposed: this corresponds with values measured in the Belgian refineries.

Th e total NO_X emissions of the combustion installations (boilers, furnaces, CHP) of the Belgian refineries:

- year 1990: 7614 ton
- year 1995: 5776 ton
- year 2000: 5988 ton

Fuel switch is considered as measure for reduction of PM and SO_2 emissions. Why not specifically for NO_X? Switching from heavy fuel to gas also reduces NO_X emissions significantly.
Also, switching to gas + the installation of low NOX gas burners is possibly less costly than the installation of low NO_X oil burners.

“2.3.2.3. Methodology to calculate the application rate”: why is it explained to calculate application rates for fuel mixtures? Why aggregated and not separatly for reference installation 01 and reference installation 02?

2.3.3 Combustion in refinery: SO_2 emissions

The background document considers following abatement measures:

- fuel switch HF - gas
- wet scrubber

In addition the BREF on refineries considers the following measures as BAT to reduce SO_2 emissions:

- switching to other low-sulphur fuels than gas (lower sulphur residual fuel, gasoil)
- cleaning all refinery gas (and desulphurisation of liquid fuel)

In table 2.11 of the background document an emission factor of 20 mg/Nm³ SO_2 for gas fired combustion installations is proposed (reference installation code 02). Also no SO_2 abatement measures for the gas fired combustion installations are considered.
Does this means that the background document assumes that all sulphur containing gases used in the refineries are cleaned in amine scrubbers and that SO_2 emission from the combustion of not (fully) desulphurised refinery gases is not considered? If so, probably a significant SO_2 reduction potential in the European and non-European refineries is not taken into account. Cleaning of refinery gas (being BAT) should be considered as a reduction measure (in CLE or in the cost curve).
The small portion of the refinery gasses in the Belgian refineries which is currently still not cleaned in amine scrubbers, causes an emission of about 600 tons SO_2. (in addition: the combustion of the ‘cleaned’ refinery gasses in the Belgian refineries still gives a rest SO_2 emission of a few hundred tons).

For the reference installation code 01 a default value of 3400 mg/Nm³ (2 % S) is put forward as uncontrolled SO_2 emission factor.

Following table gives an overview of the fuel consumption (amounts and sulphur contents) in the Belgian refineries for the reference year 2000 (boilers, furnaces, CHP).

Fuel	consumption (kt/a)	Sulphur content (weight %)	
		average	min - max
Heavy fuel oil	150	3,2	2,0 -5,0
Fuel oil	345	1,0	0,53 - 1,81
Desulphurised fuel oil	15	0,1	0,07 - 0,12
Refinery gas	740		0,01 - 0,12
Sour gas (not desulphurised refinery gas)		2,35 vol %	1,3 – 10 vol %
Natural gas	270	0	0

Th e total SO_2 emissions of the combustion installations (boilers, furnaces, CHP) of the Belgian refineries:

- year 1990: 30321 ton
- year 1995: 25534 ton
- year 2000: 15798 ton

5.1 Fluid Catalytic Cracking Unit: general information

The background document states that the SO_2 emissions from an FCC in a refinery amount to some 20 to 30 % of the total refinery SO_2 emission. For NO_X and for particulates emissions from an FCC amount respectively to about 15 to 30 % and to about 30 to 40 % of their total refinery emissions.

In Belgium two refineries are equipped with FCC units: one refinery has two FCC units currently using light desulphurised feed (capacities recently increased in the period 2000 - 2003: one from about 1000 to about 1500 kt/a, another from about 3000 to about 4000 kt/a), another refinery has one FCC unit currently using deep desulphurised feed (current capacity about 1750 kt/a).

History of the total SO_2, NO_X and PM emissions of these three Belgian FCC units:

FCC emissions (tonnes)	1990	1995	2000
SO_2	5290	5877	3794
NO_X	2065	1662	1316
PM	631	320	441

The emissions from the three Belgian FCC units compared to their total refinery emissions (period 2000 - 2003) are somewhat different from the percentages presented in the background document.

FCC emissions (percentage of total refinery emission)	Background document	Belgian refinery A (2 FCC units) (period 2000 - 2003)	Belgian refinery B (1 FCC unit) (period 2000 - 2003)
SO_2	20-30 %	35-50 %	0,5-1 %
NO_X	15-30 %	25-35 %	10-15 %
PM	30-40 %	35-50 %	10-15 %

5.2 Fluid Catalytic Cracking Unit: definition of reference installation

For Belgium preferable two reference installations should be defined:

- FCCU using light desulphurised feed (≈ reference installation 01)
- FCCU using deep desulphurised feed

For the FCC unit using deep desulphurised feed certain reduction measures do not need to be considered.

At the moment the FCC activity does not exist in the RAINS module as a separate sector. In case it is decided to modify the RAINS structure to include FCC as a separate sector, but to proceed with just one reference installation for FCC, than the use of desulphurised feedstock should be considered as an abatement measure.

5.3.1 Fluid Catalytic Cracking Unit: NO_X emissions

The uncontrolled NO_X emission factors for FCC units presented in the background document range from 500 to 800 mg/Nm³. For the three Belgian FCC units following uncontrolled NO_X emission concentrations are reported in the period 2000 and 2003:

- FCC unit using light desulphurised feed: 340 - 400 mg/Nm³
- FCC unit using light desulphurised feed: 575 - 675 mg/Nm³
- FCC unit using deep desulphurised feed: 890 - 920 mg/Nm³

Actual separate feed throughput figures for FCCU have not been reported by the refineries. At the moment we are not sure if the refinery sector is willing to provide these figures. Emission factors in kg/t feed could therefore not be calculated, but estimations show coherence with figures presented in the background document.

For SCR a removal efficiency of 80 % is proposed in the background document. According to the BREF on Refineries removal efficiencies of 85 to 90 % are achievable with SCR on FCC units. According to our recent study on the reduction potential of air emissions in the Belgian refineries a removal efficiency of 90% is achievable with SCR on FCC units.
So far SCR (or SNCR) has not been installed on FCC units in the Belgian refineries.

For the future DENOX catalyst additive should be considered as a possible abatement measure (cost effective abatement measure with removal efficiencies up to 40 - 50 %).

5.3.2 Fluid Catalytic Cracking Unit: SO_2 emissions

The uncontrolled SO_2 emission factors for FCC units presented in the background document range from 3500 to 4000 mg/Nm³. For the three Belgian FCC units following SO_2 emission concentrations are reported in the period 2000 and 2003:

- FCC unit using light desulphurised feed: 1565 - 1830 mg/Nm³
- FCC unit using light desulphurised feed: 1535 - 1860 mg/Nm³
- FCC unit using deep desulphurised feed: 230 - 250 mg/Nm³

No DESOX catalyst additive or wet scrubber techniques are currently used in Belgian refineries. Proposed removal efficiencies for DESOX catalyst additive (45 %) and wet scrubber (90 %) in the background document are in line with our own data.

DESOX catalyst and wet scrubber are not suited for FCC using deep desulphurised feed.
The use of low sulphur feedstock should be considered as reduction measure (see also BREF). A possible way to go forward (if only one reference installation with a high uncontrolled emission factor is defined) is not to make a distinction between wet scrubber and low sulphur feed as abatement technique (similar rest emission concentrations are obtained by both abatement techniques).

The background document mentions SO_2 emission factors in kg/t feed which are a factor 1000 too low.

Actual separate feed throughput figures for the catalytic crackers have not been reported by the refineries. Emission factors in kg/t feed could therefore not be calculated.

5.3.3 Fluid Catalytic Cracking Unit: PM emissions

The uncontrolled PM emission factor for FCC units presented in the background document amounts to 600 mg/Nm³. For the three Belgian FCC units following PM emission concentrations are reported in the period 2000 and 2003:

- FCC unit using light desulphurised feed: 100 - 320 mg/Nm³
- FCC unit using light desulphurised feed: 140 - 325 mg/Nm³
- FCC unit using deep desulphurised feed: 240 - 260 mg/Nm³

Actual separate feed throughput figures for the catalytic crackers have not been reported by the refineries. Emission factors in kg/t feed could therefore not be calculated.

Proposed removal efficiencies for PM abatement measures in the background document are in line with our own data.

6 Sulphur Recovery Plants

The reference installation is defined as a standard Claus Unit (2 Claus stages) with a plant size of 33 kt/a.

Sulphur recovery plants in the Belgian refineries have following capacities and operate with following efficiencies and rest emissions.

Belgian refineries	capacity sulphur recovery plants (kt/a)	efficiency sulphur recovery plants (%)	emission factor (mg/Nm³)
refinery 1	2 x 145	99,9 [a]	500 - 1000
refinery 2	2 x 70	99,0 [b]	20000 - 25000
refinery 3	40	≤ 97,5 [c]	30000 - 35000
refinery 4	10	≤ 97,5 [c]	-

a) 3 Claus stages + TGTU (SCOT)
b) 2 Claus stages + TGTU (IFP)
c) 2 Claus stages

History of the total SO_2 emissions of sulphur production plants in Belgian refineries:

SRU emissions (tonnes)	1990	1995	2000
SO_2	5265	4691	4082

Actual sulphur production figures have not been reported. Emission factors in kg/t sulphur could therefore not be calculated, but estimations show coherence with figures presented in the background document.

ADDITIONAL ITEM: FLARES

The in total 7 refinery flares in Belgium emit a considerable amount of SO_2 (and to a lesser extent PM and NO_X): for SO_2 the refinery flares in Belgium currently emit a total of about 2,6 kton. It is estimated that the SO_2 emission from flaring will relatively increase (due to planned measures on other installations) and in 2010 will make up 20 to 25 % of the total SO_2 refinery emission in Belgium. The background document does not make any reflection on the emissions of flares. Besides the Fluid Catalytic Cracking units and the Sulphur Recovery plants, also flares should be considered as a significant source of process emissions.

CONCLUSIONS

According to our assessment the proposed abatement measures and other presented information in the draft background document do not seem to be in full compliance with the requirements of the LCP and IPPC directive (BREF notes).

Flares, an important source of (SO_2) emissions in the refineries, has been disregarded in the background document.

The country specific data that need to be collected to describe the refinery sector as proposed by the background document, are not for all parameters available in Belgium.

To end, Belgium has recently finalised its assessment of the Belgian RAINS data for the NEC review (bilateral consultations with IIASA were held in September of this year) and we are therefore hesitant to redo this work. Before putting new effort on obtaining and submitting all country specific data and before filling in detail the ECODAT database for refineries, we would like to know the view of other parties and some clarification on questions below:

- if endorsed, will IIASA use the background document and ECODAT for refineries has one source besides other sources of information to change the RAINS data on refineries or is the intent to fully use the work of the EGTEI expert group?
- will the structure of RAINS module be adapted to include new categories like the catalytic crackers and the sulphur production units?