Measures Necessary for the Implementation of Article 7a of the Fuel Quality Directive

Response to the European Commission Consultation

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TRANSPORT & ENVIRONMENT

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About Transport & Environment

Transport & Environment's mission is to promote transport policy that is based on the principles of sustainable development. That means minimising the use of energy and land and reducing harmful impacts on the environment and health while maximising safety and guaranteeing sufficient access for all.

The work of our Brussels-based team is focused on the areas where European Union policy has the potential to achieve the greatest environmental benefits. Such policies include technical standards for vehicle fuel efficiency and pollutant emissions, environmental regulation of international transport including aviation and shipping, European rules on infrastructure pricing and environmental regulation of energy used in transport.

Naturally our members work on similar issues with a national and local focus. But their work also extends to public transport, cycling policy and other areas largely untouched by the EU. Transport & Environment's role in this context is to bring our members together, adding value through the sharing of knowledge and campaigning strategies.

Established in 1990, we represent around 50 organisations across Europe, mostly environmental groups and sustainable transport campaigners.

We are politically independent, science-based and strictly not-for-profit.

Summary

T&E welcomed the proposal and adoption of article 7a of the Fuel Quality Directive. It provides a technologically-neutral tool to make the fuels consumed in the EU cleaner and less carbon intensive on a lifecycle basis. The appealing aspect of article 7a is the fact that fuel providers can decide to improve the greenhouse gas (GHG) performance of their fuels either by cleaning up the production processes for fossil fuels (i.e. improving efficiency in refineries, reducing flaring and venting, optimising extraction and using cleaner crudes) or by switching to alternative fuels (i.e. biofuels, natural gas, electricity). Maximising the range of options is the best guarantee for future effectiveness: the more mitigation options are left open to fuel suppliers, the more ambitious the reduction targets can be.

T&E is therefore very concerned that the solutions proposed in this public consultation will severely limit the scope of GHG reductions on the fossil side of fuel production, leaving the majority of lifecycle GHG reductions to alternative fuels. This would reduce the principle of technological neutrality and would therefore impair the future effectiveness of the law.

It’s also unfair to demand complete traceability of biofuels feedstock, while not demanding the same for petrol and diesel sold on the EU market, despite the fact that there are substantial differences in the carbon intensity of crude production.

We are convinced that the environmental benefits of accounting for different types of oil extraction and refining outweigh potential disadvantages. Reporting on lifecycle emissions needs to start now in order to create the necessary transparency for future reviews of the law.

1. Methodology for the calculation of life-cycle GHG emissions from fuels

Fuels used on the EU market will have to improve their carbon intensity by 10% by 2020 according to article 7a of the Fuel Quality Directive. As long as GHG savings of biofuels are uncertain due, for example, to the exclusion of the calculation of indirect land use change (ILUC), any percentage of savings that could come from the fossil fuels chain should be encouraged and rewarded. Furthermore, as oil completely dominates the transport sector and will probably do so for decades ahead, minor improvements in the fossil fuel chain are currently more important from a climate point of view than increased use of alternative fuels.

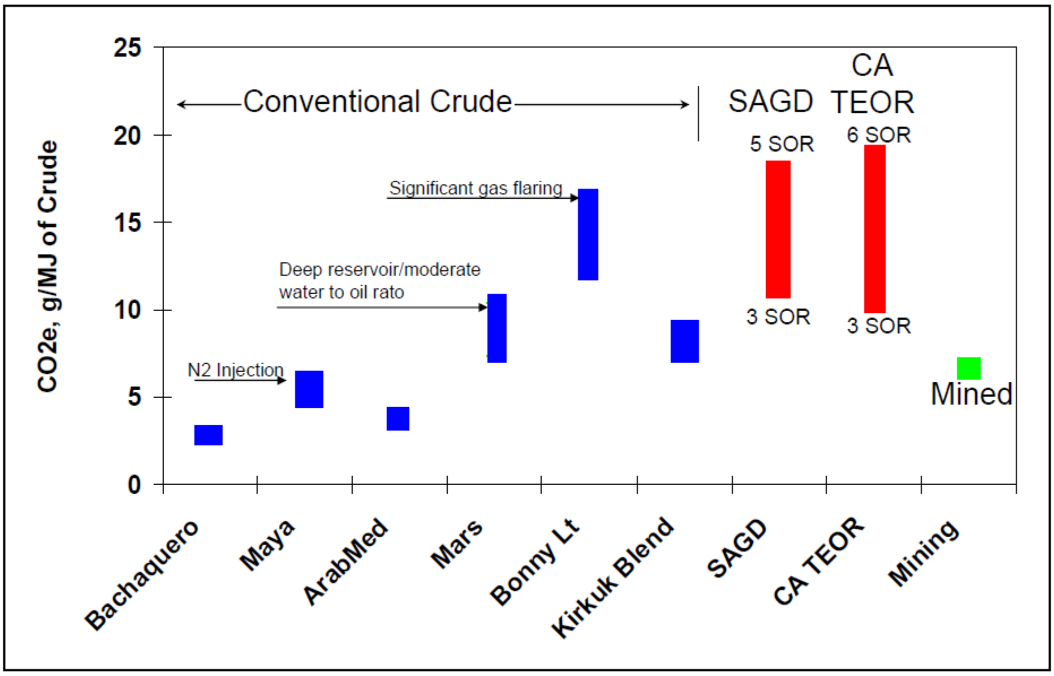
The Commission says that the difference in the total lifecycle emissions of fossil fuels regulated by this Directive is 4%. This is quite substantial considering that the required reduction in GHG emissions is 10% (6% mandatory and 4% voluntary GHG reductions). Differences become even more substantial, when looking into separate parts of the fossil fuel chain. On average, flaring accounts for 30-40% of the GHG emissions in the extraction phase. This is also the part of emissions that oil companies could reduce – if they only had an incentive to do so.

1.1 Accounting for different types of crude

If the Commission decides to propose one fixed default value for fossil fuels (extracted from crude oil)[1] as a baseline, there will be no diversification and hence no incentive for producers to use better crudes. Refiners would be able to buy low-quality crude or crude from producers with high extraction emissions and will still get the same default value. Cleaner sourcing would hence not be rewarded. Extraction emissions, particularly flaring, vary significantly from region to region and field to field (see the graph below). Ideally, the GHG intensity of crude extracted and exported from each field or each producer would be used, but this would be onerous to track and to verify.

[1] The structure of the tables on pages 16 and 17 of the consultation document is somewhat confusing. We assume that the values for "petrol" and "diesel" refer to fuels produced from crude oil. More unclear is what "tar sand" refers to - is that any kind of liquid or gaseous transport fuel extracted from tar sand? Similarly "diesel" can actually be produced from biomass. One way to clarify may be to diversify the default values both related to energy source (crude oil, tar sand, coal, wood etc.) and energy carrier (diesel, petrol, gas). It would also make sense to provide more than just one value for CCS, as this is a largely unproven technology and its GHG reduction potential may be smaller than suggested by the current default values.

GHG Emissions from Crude Production—Conventional and Unconventional Production



Graph 1: Jacobs consultancy 2008: 9.

Legend:

- *Conventional crudes—crude production by conventional means*
- *SAGD—bitumen production by steam injection using the SAGD process*
- *CA TEOR—California thermal enhanced oil recovery using cyclic steam injection in the central valley of California (Kern River)*
- *Mined—bitumen produced by surface mining. Bitumen must be separated from clay and sand*

For the above reasons it is desirable and practical to use conservative regional default values differentiated for extraction characteristics and technology used, in order to reflect the variation in carbon intensity of oil extraction and production. If companies feel they perform better than the default, they can prove it with evidence. This arrangement would limit the administrative burden, as companies would not be forced to calculate the GHG intensity of each consignment of fuels. But this approach would add to the transparency and accuracy of GHG reporting. Also, only such a framework would make GHG reductions from using different crudes feasible.

Since different oil from different regions/fields has different characteristics, refineries normally have to keep track of the oil they are processing and set their refining process accordingly. Refineries typically process only certain types of crude, and will have to analyse crude before they start processing it. As part of their business, refineries have to keep track of what goes in and out of their production. Hence, it would be just one additional step to keep track of sources of crude (by region/country), their GHG intensity and report it to the relevant authority. This would bring two benefits. Firstly, it would add to transparency and provide verifiable information on the GHG intensity of oil consumed in the EU - valuable data as the EU seeks to substantially lower its GHG emissions. Secondly, it would put a price premium on cleaner crudes based on fair reporting. This impact could multiply as more countries follow and adopt a similar low carbon fuel standard.

Of course, the default values would need to be set carefully and conservatively to get the desired result. The emissions from crude production have a considerable range. If the default values are set too optimistically, this would not provide any incentive to increase efficiency of production for more carbon-intensive crudes. If they are set at a more conservative level, the companies would have an incentive to look into ways to reduce emissions and prove that they are better than the default. For this reason it is crucial that the default values chosen are conservative and therefore provide incentive for action by producing companies.

Using one country value could be problematic. Crude emission values can vary substantially across countries. Investments made by one company may reduce emissions by e.g. 20% but the default country value may go down only by e.g. 3% (weighted average of all crudes). The net result will be that the company will not make the investment. In fact the investment will be contingent in theory on the view of the future path of the default value. Although it seems like there is certainty with a default value (there is if it remains in place for ever) there is great uncertainty about the future actual value which could lead to less investment in emission reduction strategies. In the case of Russian gas flaring – as fields mature it is likely that the crude emissions factor will increase – assuming nothing is done to reduce emissions – even with falling production.

To conclude, it would be optimal to use conservative default values that are differentiated by:

- energy source (crude oil, tar sands or Coal-to-liquid (CTL)
- energy carrier (diesel, petrol)
- region/nation
- production/extraction method.

Only truly reflecting the carbon intensity of the crude will bring the desired results in reducing GHG intensity of oil used in the EU. In short, one default value (for fuels derived from crude oil) seriously limits the opportunity to achieve GHG savings on the fossil fuel side. Default values also need to be regularly (i.e. annually) updated, otherwise there is no incentive to reduce emissions, as companies do not get benefits for their investments.

1.2 Accounting for differences in refinery performance

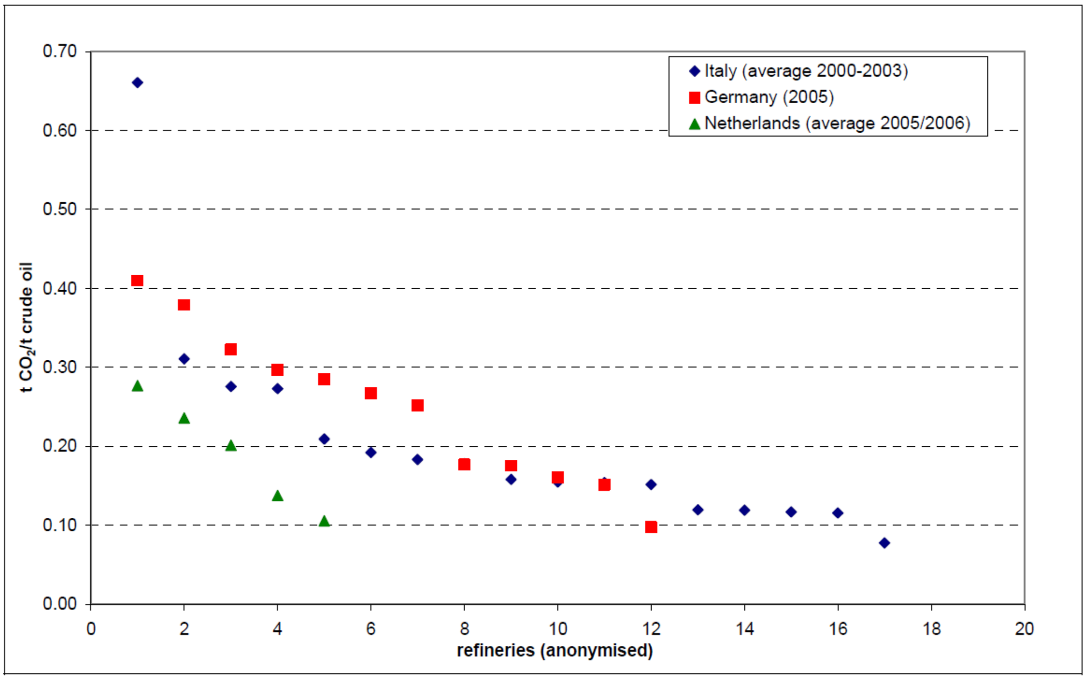
It is worrying that the Commission has attempted to exclude efficiency improvements from refineries from the GHG methodology. As discussed above, technological neutrality is a key principle of the FQD and limiting it would penalise "good" companies which invest in improving their efficiency. As several studies suggest, increasing efficiency decreases production costs and thus adds to the competitiveness of the refinery. Furthermore, refineries are already part of the ETS, so improving the efficiency of their production would bring them double benefits under the existing regulatory framework, provided that they are included in the FQD methodology for article 7a.

The Commission makes an argument that "using a precise method to estimate GHG impacts of products from each individual refinery could run the risk of leading to incorrect or perverse conclusions… as the level of GHG emissions of a refinery reflects primarily its size and complexity rather than its carbon efficiency".

The Öko-Institut and Ecofys analysis of refineries in three EU Member States (Germany, Netherlands and Italy – see Graph 2 below) shows that specific CO2 emissions are extremely divergent and that the Dutch refineries are in general more efficient than in two other Member States. Furthermore, the research on the case of Germany has also shown that there is no correlation between complexity of refinery (Nelson index) and emission levels (see Graph 3 below). As a consequence, a complex refinery does not emit more than a refinery with less units (Öko-Institut and Ecofys 2008: 72).

We would also like to draw the attention of the Commission to the Salomon index of refinery efficiency, which is adjusted to complexity and compares the energy use of one refinery with its "peer group". In recent years, Salomon has also developed a methodology to benchmark greenhouse gas emissions from refineries, resulting in a GHG Intensity index (GHGII) and they are currently developing a Carbon Emission Intensity (CEI) index.[2] In 2006 85-90% of the refining capacity in the EU27 was included in the Salomon survey, which means that there is an excellent basis for evaluation.

Figure 15 Indicative CO_2 emission data per t of crude oil for refineries in Germany, Italy and the Netherlands[31]

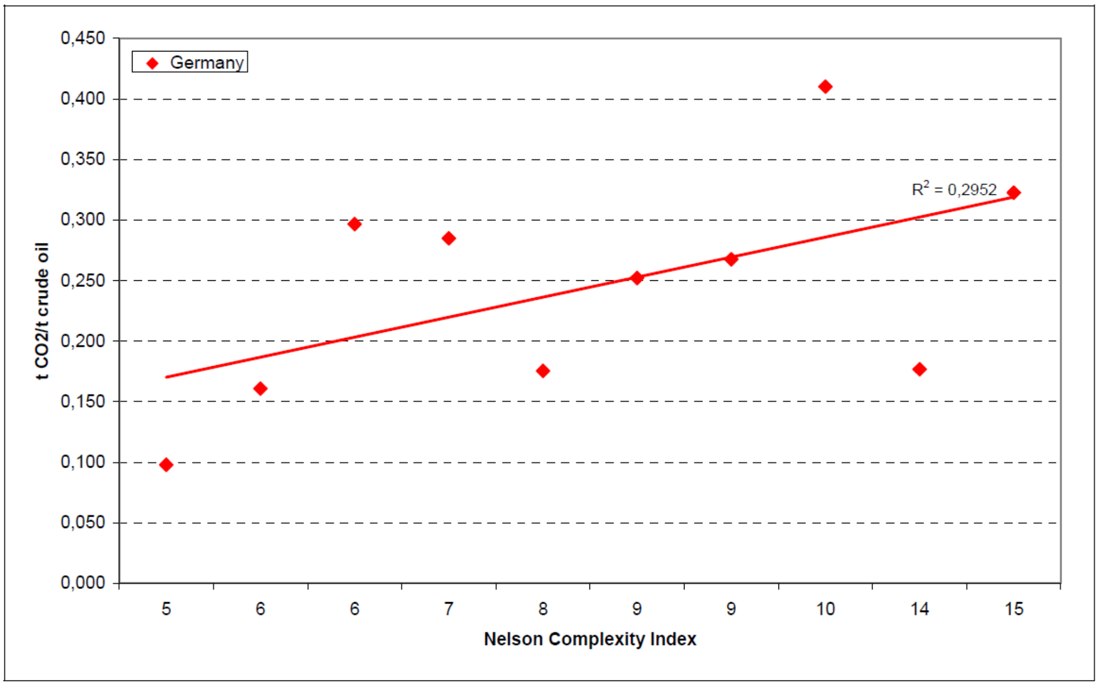


Source: Information provided by Member States

Graph 2: Ecofys and Öko-Institut 2008: 72.

[2] In addition to CO2 emissions from direct fuel consumption, sources include flare losses, CO2 emissions from catalyst regeneration and CO2 from hydrogen production. It also includes CO2 emissions from purchased electricity and steam and methane from venting, flaring and fugitive emissions (Öko-Institut and Ecofys 2008: 64).

Figure 16 CO_2 emissions per t of crude oil in relation to the Nelson Complexity Index for German refineries



Source: Information provided by Member States, OGJ (2007)

Graph 3: Ecofys and Öko-Institut 2008: 72.

Even if refineries do not want to take part in the Salomon survey, their carbon emissions can be evaluated through the so-called “Complexity-Weighted Barrel” methodology, which provides a credible basis for comparing GHG intensity – simply expressed as “metric tons of GHG per CWB”. To obtain a refinery’s CWB, each process unit technology type within a refinery is assessed to give a “process carbon emissions” factor (PCETM) which is a measure of CO2 intensity for the process type relative to the basic process of crude distillation. PCE is multiplied by the throughput for that process type to arrive at the CWB for that process type (Öko-Institut and Ecofys 2008: 68-69).

Besides these globally developed efficiency indices, there are also attempts to develop a CO2 benchmark in the framework of the ETS Directive, which could potentially be extended and adjusted for the evaluation of the refinery emissions under the Fuel Quality Directive.

We urge the Commission to look into ways to reward refinery efficiency improvement and fuel switching, which increase efficiency of refineries and keep it part of the GHG methodology from fossil fuels under article 7a. Refinery complexity does not seem to be a convincing argument not to go ahead, and therefore we do not agree with the associated security disadvantages mentioned in the consultation document either. Reporting has to start in order to create the necessary transparency.

1.3 Accounting for flaring and venting emissions

We would like to emphasise that the only practical way to take into account flaring and venting reductions is a) to assign conservative default values to crudes from different regions and different production processes and b) offer companies the opportunity to outperform the default. If there is only a single global default value, there is no way of differentiating fuels from sources with very different carbon intensities.

Globally, flaring is responsible for 400 MT of GHG emissions annually. These data are based on satellite images, as countries often do not adequately report flaring data. The information on venting is even more restrained, as it is often not reported and cannot be registered by satellites.

However, there is a trend of a reduction in flaring and it is also the most cost-effective way to comply with this Directive. Flaring in Russia could be reduced with a 0-60$/te CO2e abatement cost. Venting costs around 20-600 $/te CO2e to abate. Biofuels and other alternative fuels are much more expensive to use. Moreover, it is also not clear, what the real GHG emissions reductions from biofuels are due to the current failure to account for indirect emissions.

However, it is problematic to account flaring reductions on the basis of CDM projects. According to experts, CDM project-based flaring reductions are very expensive to implement and carry a very significant administrative burden. For this reason, not many projects are in the pipeline - out of almost 5,000 projects in the CDM pipeline, there are only 16 active flaring reduction projects. Also country reporting of flaring levels is incomplete and often unreliable. For example, Russia currently reports officially 14 bcm/year flaring of gas, while satellite data indicate a much higher level of 35-45 bcm/y.

For this reason, we believe that the verification could be based on satellite images and be updated on a yearly basis for different countries. With appropriate care, satellite data can provide a reasonable estimate (+/-30% of flaring emissions), are not subject to misreporting and deliberate underreporting and can be assigned to a specific geographic location. This data should still be subject to annual updating and some on-the-ground verification in order to ensure reliability (although on-the-ground verification might be subject to limitations, restrictions or corruption). Validation of the process will be critical. It is also possible to calculate emissions per barrel of oil flared and assign GHG intensity to the barrel of oil produced. Establishing extraction GHG intensity could be an incentive not only for flaring reduction but for reducing GHG from other operating sources (i.e. emissions from hydrocarbon expert systems, artificial liftings, re-injection processes, gas conditioning systems, energy baseload, etc.).

The methodological option of applying CDM procedures for baselines, monitoring and emission reductions verification in upstream flaring, on a project-by-project basis, may not be, at the scale and efficiency needed, a sufficient incentive for companies. This is because so far the existing methodologies for claiming emission reduction in upstream have been too restrictive and very limited in scope, with respect to applicability conditions. This approach could become an instrument for awarding emission savings only if CDM methodologies are streamlined and become more generally and practically applicable. If the CDM rules (following up-coming negotiations in Copenhagen) evolve into a form of technical benchmark or sectoral carbon-intensive methodology, then upstream GHG savings could be accommodated in implementation of the Directive.

Flaring reductions should be appropriately rewarded, meaning that it does have to be linked with “co-product allocation” and that it can be allocated across the time period, starting from when they are proved to have occurred in line with actual reduction of GHG achieved, but also in line with estimates of how much gas would have been flared until 2020.

2. Methodology for calculating the Life cycle GHG baseline

The methodological approach proposed by the Commission seems reasonable and we would support option 3 - average based on energy - on how the proportion of different fuels should be weighted. Regarding the calculation of the baseline, we would urge that it is based on accurate reporting of the actual quantity of each fuel used in the EU in the reference year.

3. Issues relating to electricity

Use of electricity can, under some conditions, lead to GHG reductions from transport energy use. However, it is absolutely essential that the accounting of electricity is based on accurate measuring, monitoring and reporting on the GHG intensity of the electricity used. Furthermore, we believe that in line with the approach for the GHG methodology for transport fuels, the GHG intensity of electricity and hydrogen should also be based on the full lifecycle evaluation. This means that the average energy use for feedstock production or extraction (i.e. uranium and coal mining, natural gas recovery) as well as transport of this feedstock to the electricity production sites should be included in the GHG methodology.

The EU average is not the most accurate way of accounting for GHG emissions from the electricity used in transport. Firstly, it would mean that many countries, where prevailing power sector emissions are high would be able to claim that their electric cars are actually cleaner by using the EU average for their calculation. Secondly, it would exclude from the calculation the impact different charging times have on electricity demand and consequently production. It is becoming increasingly clear that electric cars might encourage increased demand for marginal electricity, which might be coal or natural gas, depending on the regional mix of power generators. The second issue should be further evaluated through appropriate research.

Until then we would support a more diversified approach to GHG accounting of electricity. National averages are in this respect better than the EU average, but there are also other options, such as specific metering or asking suppliers to report on the GHG intensity of electricity supplied.

Specific or “smart” metering, especially for “home charging”, seems to be a prerequisite for the regulation of electricity used in cars, both in terms of quantity and quality. This is not an impossible task, as some providers are already promising a special plug that would come together with an electric car. Therefore, providing a special meter for home charging or even equipping each electric car with a special meter, from which it could be clear, how much electricity the car has consumed – in a similar way as conventional cars measure the number of km driven – could be considered as an option.

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