CRUDE OIL GREENHOUSE GAS EMISSIONS CALCULATION METHODOLOGY FOR THE FUEL QUALITY DIRECTIVE

Report by the international Council on Clean Transportation to the European Commission Directorate-General for Climate Action

THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

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Overview: Calculation and regulation of upstream emissions from crude oil

In 2009 the European Union (EU) amended the Fuel Quality Directive (FQD)[1] to introduce a target for European transport fuel suppliers[2] to reduce the lifecycle carbon intensity of their fuel[3] by at least 6% by the end of 2020. This makes the FQD part of a growing international trend to regulate life cycle emissions from the fuel sector. These include efforts in the USA (Renewable Fuel Standard) and several of its states, most notably California (Low Carbon Fuel Standard), as well as in Canada. It is a parallel policy to the EU's Renewable Energy Directive (RED)[4], which sets targets for the use of renewable energy in the transport fuel pool. The FQD is a performance-based standard under which performance is assessed through lifecycle analysis (LCA). The lifecycle approach seeks to measure the amount of carbon equivalent emissions that result from the whole process of production of transportation fuels, from their extraction or cultivation to their refinement or processing (so called "well-to-wheel" emissions). The measurement of these emissions defines the carbon intensity (henceforth 'CI') of each fuel type.

The carbon intensity reduction target is expected to be met largely by substituting fossil fuels with lower carbon intensity fuels such as biofuels, liquefied petroleum gas, natural gas, electricity and/or hydrogen. The Directive also includes the possibility to deliver carbon savings by reducing the upstream emissions (i.e. emissions occurring before the feedstock reaches the refinery gate) of fossil fuels. The FQD includes a detailed methodology for assessing the CI of biofuels, but for gasoline and diesel only a single default carbon intensity value of 83.8 gCO_2e/MJ is provided. The European Commission is required to develop an Implementing Measure laying out a methodology for the calculation of the greenhouse gas (GHG) emissions from fossil fuels. The Commission has made an initial proposal (see Committee on Fuel Quality, 2012), but the European Council requested further impact analysis and to date nothing has been adopted.

The purpose of the work that follows is to provide information on possible calculation frameworks to estimate and report the lifecycle GHG emissions from transport fossil fuels placed on the EU market. In particular, the focus of this work is on possible 'hybrid' reporting schemes. Under a hybrid scheme, transport fuel suppliers would be given the option to either 'opt-in' to report a default value for each batch of fuel, or 'opt-out' and provide an actual calculation of the carbon intensity of that fuel batch. The goal is to identify a system that is implementable, would impose a reasonable level of burden on economic operators and Member State regulators alike, and would be able to deliver real emissions savings to contribute to the European Union's 2020 6% reduction target.

Implementing a hybrid-reporting scheme would introduce additional opportunities for regulated parties to reduce the reportable carbon intensity of

1Directive 2009/30/EC
[2] The FQD primarily applies to road transport fuel. The precise definition of which fuels are affected by the target is available in the Directive, http://ec.europa.eu/environment/air/transport/fuel.htm
[3] Including electricity supplied for transportation.
[4] Directive 2009/28/EC

the fuels they supply in Europe, and thus comply with the FQD. Some of these reportable carbon intensity reductions would represent real emissions savings, for instance cases in which oil companies invest in reducing the carbon intensity of oil extraction. By placing a value on the carbon intensity of crude oil, implementing a hybrid-reporting scheme could also influence investment decisions and play a role in shifting investment from higher carbon crudes towards lower carbon opportunities. However, other reportable savings would exist on paper only and would not reflect real global reductions in net emissions. Firstly, under a hybrid-reporting scheme it would be possible to report default emissions intensities for the higher carbon intensity crudes supplied, while reporting actual values for the lower intensity crudes. This would tend to have the effect of underestimating the overall carbon intensity of the fuel mix, and thereby make the target effectively less stringent, reducing the total net emissions savings achieved. Secondly, there is the possibility of 'crude switching', with lower carbon intensity crudes being preferentially supplied into Europe and higher carbon intensity crudes being used elsewhere. While, as noted above, this could have the effect of shifting some investment decisions in favor of lower carbon intensity oil extraction, such crude switching would not directly be associated with net global emissions reductions.

As well as affecting the carbon intensities reportable by regulated fuel suppliers, introducing hybrid reporting could shift the overall level of emissions reductions required to meet the 6% target. In particular, if reportable defaults are elevated compared to estimated average emissions intensities, this would have the effect of increasing the total emissions savings that would be required to record a 6% reduction. Similarly, if the underlying trend in the carbon intensity of the European crude supply were towards increasing carbon intensity, then recognizing that in the regulatory assessment would preserve the environmental goals of the program, but at the cost of increasing the burden of compliance on regulated parties.

This report finds that the direct administrative cost of hybrid reporting should be modest to both regulated parties and administrators, given an efficient implementation of reporting rules. In particular, the cost of tracking carbon intensity information under a hybrid system is likely to be negligible compared to the cost of a barrel of oil (measured in fractions of a eurocent per barrel). A larger cost burden or cost saving will potentially be caused by changes in the total number of tonnes of carbon dioxide emissions reductions that would be needed for compliance. Creating new opportunities to report emissions reductions should make the compliance less burdensome overall, but increases in the reportable carbon intensity of the crude mix (due either to real changes or elevated defaults) would make compliance more burdensome. The highest potential costs from implementing crude differentiation would come in the case that a general increase in the carbon intensity of the crude mix was combined with elevated defaults and the imposition of iLUC factors. In general, the environmental benefits of hybrid reporting increase as the costs of the program increase – the costs come from delivering increased emissions savings. The most burdensome reporting scheme (Option 3, elevated by feedstock/MCON) will also deliver the largest environmental benefits.

It is important to note that crude oil carbon intensity reporting would not be the only GHG emissions reduction policy that may potentially be affected by carbon leakage. Concerns regarding indirect land use change emissions from biofuel production are well documented, while both renewables and efficiency policies may suffer from ‘rebound’ effects (where changing prices reduce the net displacement of fossil fuel combustion that is achieved). Still, it is important for policy makers to consider these issues before introducing disaggregated fossil fuel carbon intensity reporting. It is also important to place crude oil carbon intensity reporting in the context of a longer-term climate change strategy. If regulating the carbon intensity of oil extraction is a long-term strategic objective, a hybrid reporting scheme could represent a balanced first step towards that goal.

Beyond analysis of the cost and benefits of hybrid reporting, the report outlines the basis of a reporting system for both default and actual carbon intensities at the crude trade name level. These methodologies are based on the use of the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), an upstream carbon intensity estimation tool already used for regulatory reporting in California under the Low Carbon Fuel Standard (LCFS). Building on work presented by Malins et al. (2014), the report suggests a methodology based on ‘representative crudes’ for setting default values. This methodology is designed to accommodate the limitations in data availability that is often faced when assessing upstream crude oil extraction emissions. In contrast, the proposed methodology for actual carbon intensity calculations is based on the premise that a regulated party choosing to opt-out of defaults and instead use actual values would have access to data directly from oil field operators. It is therefore proposed that a relatively extensive data set should be required for actual value reporting. The most rigorous program implementation would require that data be routinely collected by upstream operators, and hence there would be no meaningful difference in data handling costs for reporting tens of data points as compared to only a handful. For European refiners, the data tracking exercise would be trivial compared to data handling routinely undertaken within any modern industry. Finally, the report presents estimates of carbon intensities calculated with OPGEE for a set of crude oils that represent the bulk of the European crude oil mix.

Overview of this final report on greenhouse gas emission reduction opportunities from venting and flaring

CHAPTER	ELEMENTS
Executive summary	Executive summary of overall findings Policy recommendations from this report
Chapter 1 (Tasks 1 and 5)	Review of key studies outlining compliance, administrative and other costs of hybrid reporting schemes Overview of fraud prevention options Comparison of baseline and hybrid reporting options in terms of administrative burden, emission reduction potential and compliance costs
Chapter 2 (Task 2)	Overview of the proposed default value estimation methodology using OPGEE Overview of the OPGEE model and data input requirements Review of fossil fuel pathways not directly modelled by OPGEE, including gas-to-liquids and coal-to-liquid pathways, oil shale, tight oil fracking, tar sands, CO_2 enhanced recovery and deep water offshore.
Chapter 3 (Task 3)	Association of oilfields with trade names Calculation of average GHG emissions for crudes by trade name List of default emission values for crudes refined in the EU, including values for North American MCONs (based on data from California ARB)
Chapter 4 (Task 4)	Consideration of key assumptions in default value setting Review of issues relating to setting elevated values Consideration of appropriate frequency of update
Chapter 5 (Task 6)	Proposed requirements and methodology for reporting actual values
Annex A	Full list of fields by MCONs and carbon intensity

Executive Summary

The European Union's Fuel Quality Directive (FQD, Directive 2009/30/EC) sets a target to reduce the carbon intensity of fuel and energy supplied for use in EU road vehicles and non-road mobile machinery by 6% by 2020, compared to a 2010 baseline. In this context, the European Commission has been working to establish an accounting methodology for estimating the carbon intensity of fossil fuels consumed in the EU. In this report, the ICCT has been given the task of evaluating different regulatory options for a hybrid-reporting scheme for fossil fuels under the FQD based on our prior work for the commission under service contract CLIMA.C.2/SER/2011/0032r. The options that have been considered are:

1. Option 0: average EU default values per crude/feedstock trade name without the option to report actual values estimated by the supplier ('the baseline').
2. Option 1: suppliers may choose to report either own actual values for each feedstock/crude (by trade name) or a set of elevated EU default values per fuel type ('elevated by fuel').
3. Option 2: suppliers may choose to report either own actual values on the basis of feedstock/crude trade name or a set of opt-in average EU default values per fuel type ('average by fuel').
4. Option 3: suppliers may choose to report either own actual values on the basis of feedstock/crude trade name or elevated default values per feedstock/crude trade name ('elevated by feedstock/MCON').

In this report, the term 'actual values' is used to distinguish the use of default carbon intensity values assigned to fuel categories by the European Commission from the calculation of fuel specific carbon intensity values by a regulated party, based on the European Commission's approved methodology. A proposal for an actual value calculation methodology is presented in Chapter 5. 'Actual values' therefore represent best estimates of the real carbon intensity of each fuel.

This summary highlights key findings and conclusions drawn from the body of the report.

ES.I. Task 1 & 5: Review and assessment of costs and environmental benefits related to hybrid reporting options

For this task, existing studies on the potential costs of implementing fossil fuel accounting under the FQD are reviewed, and based on that review potential costs are assessed for the four implementation options specified in this report. The studies reviewed are a report by CE Delft for the NGO Transport and Environment, an ICF report for the European Commission DG Clima and a Wood Mackenzie study for the European refining industry. Each of these studies considered the implications of one or more differentiated crude carbon intensity reporting options, with crude differentiation at the level of feedstock, or individual crude types. There is considerable divergence in terms of the costs associated with crude carbon intensity reporting anticipated in these different studies. However, in all cases the administrative cost of reporting and data tracking is minimal compared to compliance cost for the policy as a whole, and even more so compared to the cost of crude oil. We see no reason to believe that costs to regulated parties should rise beyond the order of a eurocent per barrel of oil for either a hybrid system or for a system (e.g. Option 0, the baseline) in which simple readily available information is tracked (i.e. feedstock or MCON name).

ES.I.i. CE Delft Report

CE Delft assess a reporting system under which fuel suppliers would be required to identify the feedstocks used to produce fossil transport fuels from a list of conventional oil, bitumen, kerogen, coal or gas. Each of these categories of fuel would have a default carbon intensity assigned to it. This would have some similar to some options covered in the current report (mainly Option 0 in that there would be no accommodation for actual value reporting) but the feedstock level defaults would be used for compliance accounting by regulated parties. The CE Delft reporting requirements would require implementing data tracking for the feedstock origin of crudes entering the EU. In general, this would not require any additional chain of custody, and a refiner should be aware of any non-conventional crude (e.g. bitumen or syncrude) being processed from the assay. Dealing with imports of intermediate and finished products (representing the equivalent of between 20-25% of crude imports) would be more difficult, as in general data tracking systems are not in place to easily identify the origin or feedstock of the crudes processed into these products. Regulating intermediates and finished products would therefore require new systems to be developed and implemented.

Based on about 100 EU refineries, CE Delft estimate an annual cost of compliance to the EU refinery sector of 35 to 64 million euros. On top of this, they estimate that costs incurred by traders could represent an additional 20%, giving a total compliance cost range of 42 to 77 million euros. Assuming that costs scale linearly, the CE Delft estimated range would be increased between 56 to 103 million euros for the full number of refineries (129) in the EU. These administrative costs would be very modest compared to the cost of oil, amounting to approximately 1 eurocent per barrel of crude.

ES.I.ii. ICF Report

In 2012, the European Commission contracted ICF to undertake an impact analysis comparing the implications of several options for fossil fuel accounting under the FQD, "Impact Analysis of Options for Implementing Article 7a of Directive 98/70/EC (Fuel Quality Directive)." The results of this impact analysis are taken as key inputs for this report.

The ICF study considered six accounting options (see Table ES.1). We will refer henceforth to the options from the ICF report as ICF 0, ICF 1, ICF 2, etc. We have focused on the options ICF 1, 3 and 4 since these are the most comparable to the options considered in this report. ICF's baseline, ICF 0, is a case in which a single default value is used for all fossil fuels and is not updated over time. As with the options analyzed within this report, to aid clarity we will sometimes also refer to these ICF options with shorthand descriptions. ICF 0 is the ‘ICF baseline’, ICF 1 is ‘ICF, defaults by feedstock’, ICF 3 is ‘ICF hybrid, average defaults’ and ICF 4 is ‘ICF hybrid, elevated defaults’. The ICF report analyzes the costs potentially associated with ICF options 1 to 3 in detail. We assume that the administrative costs of ICF 4 would be similar to those of ICF 3.

Table ES.1. Crude oil emissions accounting options from the ICF study

OPTION		METHOD TYPE	LEVEL OF DISAGGREGATION FOR UNIT GHG INTENSITY		UNIT GHG INTENSITY SPECIFIC TO FEEDSTOCK MIX OF:
			Fuel or feedstock	Feedstock categorization	
ICF 0		Default unit GHG intensity for the European Union	Fuel	N/A	EU
ICF 1		Default unit GHG intensity for the European Union by feedstock	Feedstock	10 categories, specified in EC proposal (Note 2)	EU
ICF 2		Default unit GHG intensity for each Member State (MS)	Fuel	N/A	MS
ICF 3	Opt-In	Default GHG intensity for opt-in suppliers by each feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)	All suppliers choosing to Opt-In
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers choosing to Opt-out
ICF 4	Opt-In	Conservative default GHG intensity for the European Union by feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)	EU
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers
ICF 5		Actual GHG intensity for each supplier	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers

When comparing these options, ICF considered both administrative costs and changes in compliance costs. Compliance costs are based on marginal abatement cost (MAC) curves, including options for compliance through alternative fuels and through upstream emissions reductions. ICF also consider the potential to deliver reportable emissions reductions through crude switching. The central case considered by ICF assumes that iLUC factors are not implemented for regulatory accounting. They also consider a sensitivity case in which ILUC accounting would be introduced, increasing the marginal abatement costs as some compliance options would no longer be available. With iLUC accounting included, the carbon abatement cost of biofuels increases, and some fuels become ineligible, making the marginal compliance cost more expensive. Without iLUC accounting, ICF anticipate only modest changes in compliance costs, ranging between 6 to 9 million euros. When accounting for ILUC, the picture changes substantially because of the need for alternative compliance strategies to make up for a reduced biofuel supply. As a result, compliance costs range closely above 1.5 billion euros for each of the options. In terms of administrative costs, ICF include monitoring, reporting and verification (MRV) costs for both suppliers and public authorities. Overall the administrative costs for the options covered in the ICF study range from 4.5 to 6.8 million euros with the most expensive item being the development of an LCA framework.[5] Finally, the cost to public authorities is calculated at around 50,000 euro per year for either ICF 1 or ICF 3.

Overall, the absolute costs for the ICF options range from 9 to 15 million euros as shown in Table ES.2. Introducing iLUC accounting dramatically reduces the supply of biofuels in the baseline (eliminating most biodiesel) and increases the additional emissions savings required to meet the FQD. There is therefore a compliance cost associated with implementing any reporting option accompanied by iLUC accounting, over 1.5 billion euros. It should, however, be understood that ICF also associate iLUC accounting with a cost *saving* of nearly 6 billion euros largely due to replacing biodiesel with cheaper fossil diesel. The 1.5 billion euro cost of achieving the FQD emissions reduction target would therefore be more than offset by savings from reduced biofuel deployment, in ICF's assessment. The fossil fuel emissions accounting options (ICF 1 [ICF defaults by feedstock], and ICF 3 [ICF hybrid, average defaults]) that introduce additional compliance opportunities (such as crude switching) reduce the overall cost of compliance by up to 50 million euros. That said, the difference between costs of the different reporting options is small compared to overall compliance costs, and very small compared to the cost of the fuel itself.

It should be noted that ICF did not undertake a full economic analysis, and therefore the costs quoted in the impact analysis do not consider any economic benefits or disbenefits across the system as a whole associated with the use of alternative fuels.

[5] The initial costs reported by ICF are based on a miscalculation of an assumption taken from the CE Delft study. Whereas as Delft showed that costs to traders should be around 20% of total costs, ICF applied this for each individual operator rather than as a whole.

Table ES.2. Total additional costs incurred by regulatory options ICF 0 (baseline), ICF 1 (ICF defaults by feedstock) and ICF 3 (ICF hybrid, average defaults)

ABSOLUTE COSTS			NON-ILUC			ILUC		
			ICF 0	ICF 1	ICF 3	ICF 0	ICF 1	ICF 3
Transport energy demand		PJ	10,879	10,879	10,879	10,837	10,839	10,840
GHG emissions		$MtCO_2e$	903	902	902	899	898	898
Final intensity (full joint reporting)		g/MJ	83.0	82.9	82.9	83.0	82.8	82.8
Compliance costs	biofuels	€m	-6	-6	-6	406	351	351
	UERs	€m	12	12	12	1211	1167	1167
	crude switching	€m	0	1	1	0	32	44
	product switching	€m	0	2	2	0	17	21
	total	**€m**	**6**	**8**	**9**	**1618**	**1567**	**1584**
Administrative costs*	low	€m	2	5	5	2	5	5
	average	€m	3	5	6	3	5	6
	high	€m	3	5	7	4	5	7
Total costs (with average administration costs)		**€m**	**9**	**13**	**15**	**1621**	**1572**	**1570**

ES.I.iii. Wood Mackenzie

Wood Mackenzie (2012) considered a more disaggregated emissions accounting, with 10 example crude carbon intensities – ranging from about 2 gCO_2e/MJ to about 13 g CO_2e/MJ. This is similar to CE Delft reporting requirements, but with disaggregation at the level of crude type rather than only feedstock. It is closer to Option 0 than the CE Delft approach due to allowing additional disaggregation, but again differs in that it would require accounting of disaggregated emissions for compliance purposes at the regulated party level. On compliance cost, Wood Mackenzie claim that crude and product 'shuffling' is likely to be the most cost effective way of complying with emissions reductions under the FQD. Hence, they expect that by shuffling crude supply refiners can save more money compared to a case where there is no crude differentiation. The study estimates that 13 million tonnes of reportable emissions reductions would be achievable through crude and product shuffling under the carbon intensity accounting system. Overall, they expect an additional $2-3/bbl price differential between the lowest and highest carbon crudes available. Woods Mackenzie does not seem to allow for the possibility that differentiating crude pricing by carbon intensity could result in changes in production practices or investment decisions. They expect that crude shuffling will cause an increase in shipping emissions of about 1.4 $MtCO_2e$ per year. Woods Mackenzie do not present estimates for administrative or compliance costs.

ES.I.iv. Fraud prevention

By introducing pricing of lifecycle carbon intensity, a hybrid reporting option would introduce additional incentives for fraudulent behavior. While it may be possible with additional research to develop analytical chemistry techniques to support the identification of crude origin, in the near term the risk of fraud must be managed through rigorous data handling through the chain of custody. ICF and CE Delft anticipate that data assurance for FQD fossil fuel carbon intensity reporting could be managed by the International Auditing and Assurance Standards Board (IAASB). Member State authorities will play an important role in ensuring that procedures are adequate and enforceable, whoever takes the lead in designing a system.

ES.I.v. Assessment of costs for Options 0 (baseline), 1 (elevated by fuel), 2 (average by fuel) and 3 (elevated by feedstock/MCON)

The cost estimates for the options in this study are based upon the analysis presented in the ICF study. As explained in detail in Chapter 1, the ICF cost assessment has been adjusted to reflect the options in this report, and to address some inconsistencies. It should be understood that the compliance costs presented here for alternative fuels are based on the difference in price between different fuel options (as assessed by ICF). These costs do not reflect any benefits or disbenefits to the EU economy resulting from changing the supply of alternative fuels.

The administrative cost to operators is not expected to vary substantially regardless of the option taken. For Option 0 this cost (covering data tracking, verification and reporting) is expected to be of the order of €9 million per year. The administrative costs of Options 1, 2 and 3 are anticipated to be higher but similar. Depending on the level of opt-out reporting, the total cost to economic operators could be raised by up to €3 million, with Option 3 representing the highest administrative burden as it is expected that it will involve a higher rate of actual value reporting.

Costs to public authorities to implement the scheme are expected to be less. This is partly based on the assumption, which follows the expectations of the CE Delft and ICF reports that the cost of verification will be born by regulated parties. Public authority costs should be minimal for Option 0 as only very slight modifications to existing data handling would be required, while for the rest of the options the costs are expected to be of the order of €1 million per year, perhaps rising to €1.5 million for Option 3. The range of total administrative costs is assessed as ranging from €8.6 million to €13.6 million. Both administrative and compliance costs are shown in Table ES.3.

Table ES.3. Overview of Options (low and high cost span possibilities from no change to a +1 gCO_2e/MJ change in underlying carbon intensity of the crude mix)

OPTION	OPTION 0	OPTION 1	OPTION 2	OPTION 3
% Of opt-out reporting	0	40	20	60
Administrative cost, in M€ and in parentheses in € per barrel of oil[6]				
Low cost (million euro)	8.6 (0.002)	10 (0.002)	9.6 (0.002)	10.5 (0.002)
High cost (million euro)	8.9 (0.002)	12.4 (0.003)	11.3 (0.002)	13.6 (0.003)
Compliance cost (M€) and in parentheses estimated cost in euro per barrel of oil				
Low cost (no iLUC)	0 (0.00)	-80 (-0.02)	-121 (-0.02)	76 (0.02)
High cost (no iLUC)	138 (0.03)	-5 (0.00)	-6 (0.00)	147 (0.03)
Low cost (iLUC)	0 (0.00)	-964 (-0.2)	-1399 (-0.28)	929 (0.19)
High cost (iLUC)	1711 (0.35)	-450 (-0.09)	-668 (-0.14)	1604 (0.33)
Environmental performance				
Emissions savings delivered by FQD program ($MtCO_2e$)	58 – 68	54-65	50 – 60	64 – 74
Change in emissions savings from case with single default value for crude ($MtCO_2e$)	0 – 10	-4.5 – 5.5	-7.4 – 2.6	6.4 – 16.4
Level of actual reporting	None	Moderate	Lower	Higher

Compliance costs are expected to vary significantly from option to option. Compliance costs arise largely because the average reported carbon intensity of EU crudes is expected to vary from the baseline value depending on which option is implemented. If the reported average is lower than in the baseline, there is a lower compliance burden – a higher reportable emissions average means a higher compliance burden. For example, under Option 0, the only additional compliance cost (as compared to adopting a fixed value for EU average emissions) would be the cost of offsetting any increases in the carbon intensity of the underlying EU crude mix to 2020. Previous studies have anticipated an increase in that average carbon intensity by between 0.1 and 1 gCO_2e/MJ.

For Options 1, 2 and 3, as well as changes in the carbon intensity of the underlying crude slate compliance costs are also sensitive to the level of 'selective reporting' anticipated under the hybrid reporting system, and the level of elevation in any defaults. 'Selective reporting' refers to the case that regulated parties report

[6] Based on 2013 EU oil demand of 13.5 million barrels per day.

actual data only for low carbon intensity crudes, skewing the calculated average carbon intensity lower. Applying elevation to reportable default values skews the reportable average carbon intensity higher. The impact of selective reporting is expected to be largest in Option 1, where the incentive is greatest, and also important in Option 2. Either of these options is anticipated to allow reporting reduced average carbon intensities, thus a lower overall compliance burden (even given the elevation in Option 1). Under Option 3 there would be less scope for selective reporting, as defaults would be set at the MCON level. Given the application of an elevation factor to default CI values, a significantly increased reportable average carbon intensity is expected, and thus increased compliance costs.

In all options, the compliance cost implications are amplified (in either direction) in the case that iLUC accounting is implemented, because the marginal emissions savings available are moved further to the right on the cost curve.

The overall picture is that cost implications of implementing any of these options are exceedingly modest compared to the value of the EU fuel market. Administrative costs in all cases would amount to only hundredths of a eurocent for every litre of petrol or diesel sold in Europe. In the highest case for increased compliance costs, Option 3 (elevated defaults by feedstock/MCON) with iLUC reporting and a 1 gCO_2e/MJ background increase in fossil fuel carbon intensity, the cost comes to only about a fifth of a eurocent per litre of fuel.

ES.I.vi. Environmental benefits and leakage

Hybrid reporting under FQD could deliver environmental benefits in four ways:

- Driving increased emissions savings by making the target more difficult to meet;
- Driving real reductions in carbon intensity in the crude oil supply chain;
- Reducing investment in high carbon intensity oil extraction in favor of lower carbon intensity options;
- By setting the groundwork for future, more ambitious, regulatory approaches in the oil sector.

The first option, increased savings through more stringent compliance targets, would deliver genuine benefits but would be incidental to the purpose of hybrid reporting. For instance, implementing Option 3 could create a need for up to an additional 16 $MtCO_2e$ of carbon savings to achieve compliance (plus the 58 $MtCO_2e$ of total FQD compliance), but the same could be done by simply increasing the percentage target. The opportunity to deliver net emissions savings in the oil supply chain through hybrid reporting is difficult to assess, and no quantitative expectation is anticipated here. Certainly, there are opportunities to deliver efficiencies in oil extraction. Analogously, regulation of biofuel carbon intensity under the RED and in California under the LCFS has been seen to put increasing focus on process efficiency and deliver real benefits. However, it should be understood that emissions savings in the supply chain might not be the dominant effect (as opposed to selective reporting or crude switching). Additional research on opportunities to improve oil extraction efficiency will help quantify these potential benefits. It is similarly challenging to quantify the potential impacts on investment decisions of oil differentiation under FQD. While CE Delft present estimated benefits of up to 19 $MtCO_2e$/year due to changing investment decisions, this assessment is considered highly uncertain.

In contrast with potential benefits, there is space for environmental costs in some cases. Just as some hybrid schemes could incidentally increase program stringency, others could reduce it, reducing overall emissions. Woods Mackenzie has argued that crude switching could increase shipping emissions. While their evaluation seems to be based on an unreasonable assumption that all crude shipping routes are currently optimized for transport emissions, there is a real possibility that shipping distances could increase.

Overall though, the likely environmental benefits or costs of hybrid reporting are likely to be modest compared to the overall program goals, and the effect on program stringency seems likely to dominate the environmental impact. At a political level, the important question may be whether hybrid reporting is seen as a stepping-stone to more active regulation of oil extraction emissions. If the answer is yes, then using hybrid reporting as an opportunity to develop databases, reporting systems and assessment tools may be an appropriate step towards larger benefits in future.

ES.I.vii. Conclusions on costs and benefits

In general, it is expected that administrative costs will scale with the extent to which a hybrid scheme drives an increase in actual reporting. However, overall administrative costs will be very similar for any of the Options, and relatively negligible compared to the price of oil. Compliance costs and environmental benefits would largely reflect changes in the carbon intensity of the European crude mix. If the carbon intensity of the crude mix increases, there would be a compliance cost associated with offsetting that increase. Options with elevated defaults (1 and 3) would generate additional environmental benefits at additional cost. Option 2 (with average defaults) would generate some relative cost savings due to reduced environmental benefit. Anticipated total costs from implementing any of the hybrid options never reach more than a fraction of a eurocent per liter of fuel. In the strongest case considered, offsetting the combination of a 1 gCO_2e/MJ increase in crude oil carbon intensity and the elevated defaults applied in Option 3 could deliver 16 $MtCO_2e$ of emissions savings as compared to a system with a single static upstream carbon intensity for all crude.

ES.II. Task 2: Methodology for estimating crude default emission intensities

The second task of this report is to present a methodology for estimating upstream, average default values per crude/feedstock trade name (MCON) that could be included in the legislation. The proposed methodology for assigning carbon intensities to crude oils is based on the use of the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), which at the time of writing is the world's only open source lifecycle analysis model for crude oil production. The OPGEE is an engineering-based lifecycle assessment tool for the measurement of greenhouse gas emissions from the production, processing, and transport of crude petroleum. OPGEE is an upstream model - the system boundary extends from initial exploration of the oil field to the point at which crude oil is delivered to the refinery gate. OPGEE includes within its system boundaries more than 100 emissions sources from oil and gas production. Very small emissions sources are however neglected as being likely insignificant in magnitude. Importantly, the OPGEE tool is already in use for crude oil LCA under the California Low Carbon Fuel Standard (LCFS), in which context it has been subject to extensive review and public consultation.

The estimation of carbon intensities using OPGEE relies on the user entering basic data regarding the oil field being modeled. OPGEE includes embedded default values for each parameter, allowing a carbon intensity estimate to be generated even for very limited data inputs. The OPGEE defaults model a 'typical' conventional oilfield. Defaults are also available for typical bituminous oil extraction. In a previous study (ICCT 2014), the ICCT proposed a methodology for assessing the carbon intensity of a given crude grade. The methodology requires that one or more 'representative fields' feeding that crude grade should be identified, and that for each field being modeled at least half of the following parameters should be available: **field age, reservoir depth, oil production volume, number of producing wells, reservoir pressure, API gravity, gas-oil-ratio and water-oil-ratio**. The MCON carbon intensity is then calculated as the average carbon intensity of all those representative fields for which adequate data is, weighted by the quantity of oil produced at each field.

For feedstocks not modeled by OPGEE, it is proposed that default values should be based on studies in the existing literature. The main limitation on the accuracy of the assessment of default values is data availability, which is limited both at the field and MCON level. While some fields can be relatively well described, especially in regions with publicly available production data, many others have limited data, to the extent that we have only been able to model a fraction of the oil fields in the world, and several MCON carbon intensities have had to be based on data from single fields.

OPGEE models conventional oil production, but in the future fossil fuels utilized by the transportation sector are increasingly expected to be produced using enhanced extraction technologies and alternative feedstocks, such as bitumen, kerogen and/or coal. There are several pathways that are not modeled within the OPGEE framework but that are of interest for the assessment of MCONs being supplied to Europe, and which are likely to be fully included in future versions of the tool. In order that MCONs produced using these technologies can be included in the proposed reporting methodology, we have undertaken literature review for pathways using hydraulic fracturing, CO_2 enhanced recovery and deepwater offshore production, and for oil produced from tar sands bitumen, oil shale kerogen, coal and gas.

For gas to liquids (GtL) synthetic oil production, the JEC WTW study is considered an appropriate source for the upstream carbon intensity, reported as 18.7 gCO_2e/MJ. For coal to liquids (CtL), the JEC WTW study is also used, with an upstream value of 129 gCO_2e/MJ. For kerogen, a value of 52 gCO_2e/MJ is recommended based on Brandt (2011). For hydraulic fracturing, it is proposed that an additional 1.5 gCO_2e/MJ should be added to the emissions calculated by

OPGEE. Similarly, for CO_2 injection a correction factor of +3 gCO_2e/MJ is suggested.

ES.III. Task 3: Average greenhouse gas emissions for crudes by trade name

ES.III.i. Associating fields with crude names

In order to estimate the carbon intensity by crude name (MCON) of the crudes imported to Europe with the representative fields methodology, it is necessary to associate fields to individual MCONs. This data is not generally readily available in the public domain. We have associated fields to MCONs in the list used by the US Energy Information Administration (EIA) for oil import reporting using a combination of data from the CIMS database, public sources and GIS pipeline analysis.

ES.III.ii. Field data

The field data is based on the ICCT oil database detailed in Malins et al. (2014) augmented for North American crudes by data from the California Air Resources Board (ARB, 2014).

ES.III.iii. MCON carbon intensities

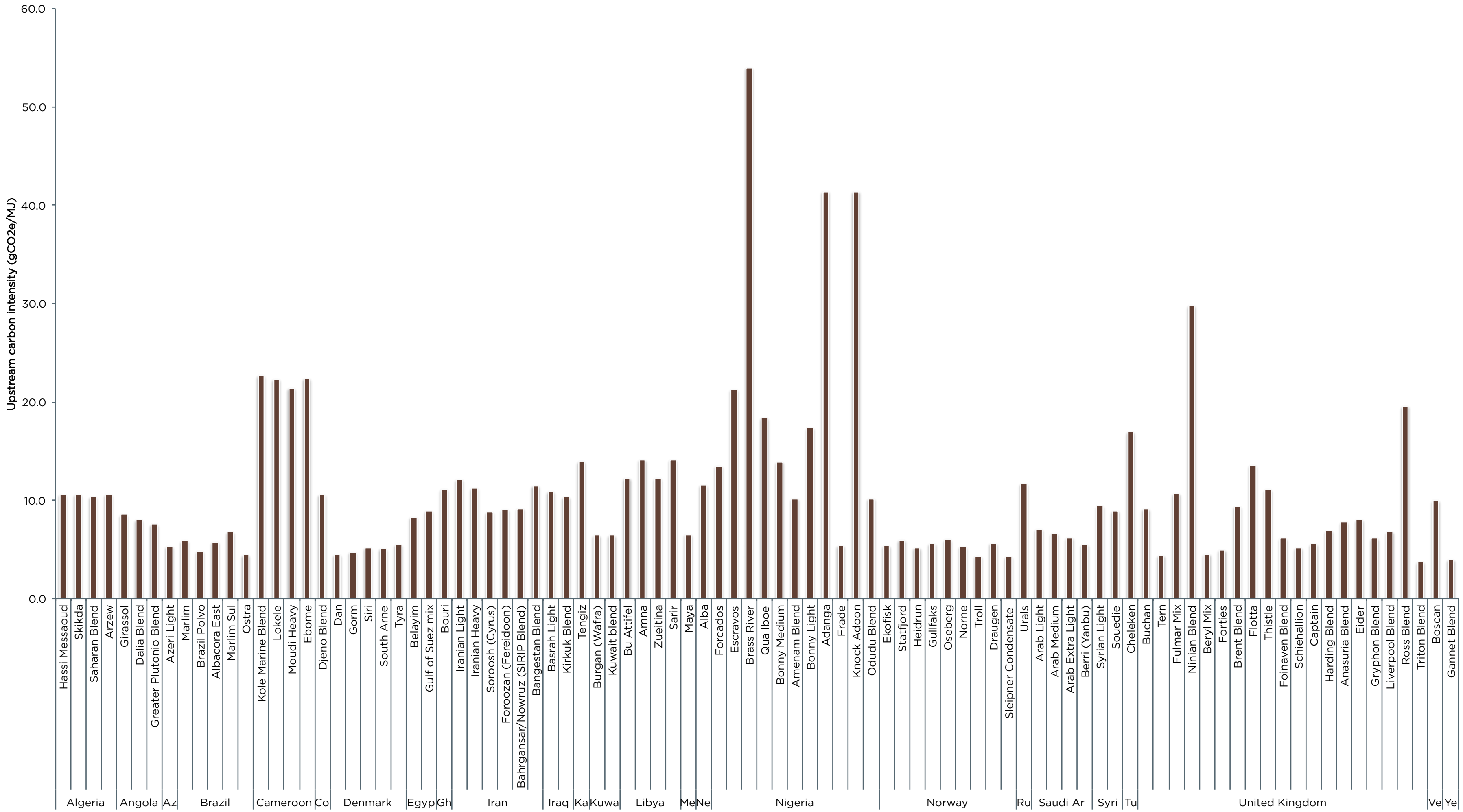

Figure A. Carbon intensity of MCONs associated with crudes refined in Europe

ES.IV. Task 4: Discussion on critical assumptions

ES.IV.i. Elevation

In a hybrid-reporting scheme, it is sometimes desirable to provide additional incentive for actual reporting by imposing higher-than-average carbon intensities as default values. An example of this is biofuel carbon intensity reporting under the RED and FQD, where 40% is added to the emissions from the processing stage of the lifecycle, and is seen as an incentive to improve biofuel production efficiencies. While applying elevated defaults creates an enhanced incentive for reporting, as shown in Chapter 1 it can also result in changes to program stringency. In the biofuel example, increasing the default emissions means that a higher volume of biofuel supply is needed to meet the FQD target.

While various approaches to elevating default values are possible (including systematic conservativeness, adding an emissions term, elevating one lifecycle stage as in the biofuel methodology, among others), it is suggested that the preferred approach for Options 1 and 3 should be a simple factor elevation. In this report, the factor suggested is a 20% increase on the upstream emissions, based on the authors' expert judgment.

ES.IV.ii.Updates to default values

Both the tools used to estimate upstream carbon emissions and the data used in those tools are subject to regular amendment and expansion. The OPGEE itself is regularly updated, largely driven by the regulatory process of the California Air Resources Board (ARB), where updates to regulatory MCON carbon intensities and the OPGEE version used for regulatory purposes are intended to occur every three years. As well as the ARB, the model development team at Stanford may release interim versions of OPGEE, and as an open source model other experts and stakeholders may consider forking new versions of the software (as indeed a version has been developed for the analysis in this report). It would not be appropriate within the European regulatory framework for default values to be updated every time a new version of OPGEE is released, but on the other hand it is important that new data and model improvements be reflected. Similarly, as the Commission, Member States and other stakeholders collect additional data on MCON carbon intensities, it is important that default values should be updated to reflect a current understanding, but over-regular amendments would introduce uncertainty and administrative burden. It is suggested that regardless of the reporting option adopted a final set of regulatory defaults should be released in 2019 for use in 2020, based on 2018 data. An additional update to the values presented in this report could be undertaken in 2016 or thereabouts, at the discretion of the Commission.

ES.V. Task 6: methodology for opt-out reporting ("actual values")

In Malins et al. (2014) and in Chapter 2 of this report, a methodology is presented for assessing the estimated typical default value for the carbon intensity of a given crude category (MCON or other aggregation). This methodology is designed with reference to the general paucity of oil field data in the public domain, and therefore allows values to be estimated based on a limited amount of data for a given field. For actual value reporting, however, allowing values to be calculated based on a very limited data set would introduce several issues. For one, it would allow cherry picking of data points that would result in the lowest possible carbon intensity. For another, part of the normal rationale for implementing hybrid carbon intensity reporting is to encourage operators to pay more attention to the carbon intensity of their production practices – a very limited data reporting requirement is unlikely to succeed in this regard.

While data for default value estimation is limited by the lack of oil field operators willing to share data, hybrid reporting need only occur in cases where a regulated party has an active relationship with an upstream operator and could request data from that operator. With the cooperation of the upstream operator it should be possible to collect more extensive data relatively easily. Where the upstream operator is unwilling to share data, it may not be possible to report actual values, but in that case opt-in reporting is still available.

It has been shown that the OPGEE can generate somewhat accurate results based on quite limited data, but with a full dataset the accuracy should be much improved. The key inputs for OPGEE are those listed on the 'User Inputs and Results' sheet of the OPGEE workbook. It is proposed that this full set (where applicable) should be required for actual value reporting for conventional oil. A different set is requisite for reporting on bitumen production. It should be relatively trivial for an upstream operator to collect this data, and there is no significant cost increase associated with applying chain of custody requirements to a set of dozens of data points instead of a handful.

The required data input have been split into two categories – one for which data should reflect the previous calendar year, and a second less time-sensitive set for which data should be not more than three years old. Rules are outlined for several special cases, such as where wells at the same field use different production practices or where production practices change during a calendar year.

Having established rules for an actual value assessment on an individual field, requirements are proposed at the MCON level. An MCON may draw from many oilfields, and it is suggested that to balance accuracy with reporting burden it should be required that 90% of the oil (by volume) feeding an MCON should come from fields for which data is reported.

1. Task 1 and 5: review and assessment of costs related to hybrid reporting options

1.1. Summary

The first task in this report sets out to review key studies on compliance and administrative costs for the regulation of fossil fuel carbon intensity in the FQD, and informed by that review to assess the likely costs and environmental implication of each of the four options.

There are three primary sources that are considered for Task 1. The first is a report by CE Delft titled “Oil reporting for the FQD: An assessment of the feasibility and cost to oil companies” for the NGO Transport and Environment. The second, and the most important source for this report, is by ICF titled “Impact Analysis of Options for Implementing Article 7a of Directive 98/70/EC (Fuel Quality Directive)” for the European Commission DG Clima. The third, and the source with the least detail provided, is a report by Wood Mackenzie for the European refining industry. The following provides a brief overview of the assumptions and conclusions from each of these studies.

1.1.1. CE Delft Report

CE Delft assess a reporting system under which fossil fuels would be disaggregated with different default emission factors based on the feedstock used: conventional oil, bitumen, kerogen, coal or gas. This would require implementing data tracking for the feedstock origin for crudes entering the EU. In general, CE Delft find that this would not require any additional chain of custody, and refiner will already be aware of any non-conventional crude (e.g. bitumen or syncrude) being processed. Dealing with imports of intermediate and finished products (representing the equivalent of between 20-25% of crude imports) would be more difficult, as in general data tracking systems are not in place to easily identify the origin or feedstock of the crudes processed into these products.

Based on about 100 EU refineries, CE Delft estimate an annual cost of compliance to the EU refinery sector of 35 to 64 million euros. On top of this, they estimate that costs incurred by traders could represent an additional 20%, giving a range for total compliance cost of 42 to 77 million euros. Assuming that costs scale linearly, the CE Delft estimated range would be increased to 56 to 103 million euros for the full number of refineries (129) in the EU. These administrative costs would be very modest compared to the cost of oil, amounting to approximately 1 eurocent per barrel of crude.

1.1.2. ICF Report

In 2012, the European Commission contracted ICF to undertake a study comparing the implications of several options for fossil fuel accounting. The ICF study considered six accounting options as follows:

Table 1.1. Crude oil emissions accounting option from the ICF study

OPTION		METHOD TYPE	LEVEL OF DISAGGREGATION FOR UNIT GHG INTENSITY	
			Fuel or feedstock	Feedstock categorization
ICF 0, 'ICF baseline'		Default unit GHG intensity for the European Union	Fuel	N/A
ICF 1, 'ICF defaults be feedstock'		Default unit GHG intensity for the European Union by feedstock	Feedstock	10 categories, specified in EC proposal (Note 2)
ICF 2		Default unit GHG intensity for each Member State (MS)	Fuel	N/A
ICF 3, 'ICF hybrid, average defaults'	Opt-In	Default GHG intensity for opt-in suppliers by each feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier
ICF 4, 'ICF hybrid, elevated defaults'	Opt-In	Conservative default GHG intensity for the European Union by feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier
ICF 5		Actual GHG intensity for each supplier	Feedstock	Actual feedstocks per product per supplier

These options do not precisely match up with the options identified by the Commission for this study, but there are similarities. The main difference between ICF's options and the options analyzed in this report is that they aggregate their reporting at the feedstock level – much like CE Delft – rather than considering reporting at the MCON level. Administrative costs, which include monitoring, reporting and verification (MRV), are based on ICF's assessment of the staff commitment required to design and operate data handling procedures. ICF consider three possible systems for assessing actual emissions, and conclude that the use of pre-defined LCA models such as OPGEE would be the least expensive. Changes in compliance costs are based on marginal abatement cost curves for low carbon compliance options (biofuels, UERs and fuel or crude switching). ICF anticipate only moderate differences in administrative and compliance costs between their options. If iLUC accounting is not implemented, total costs from FQD implementation (against a baseline of compliance with the RED) are expected to range between 6 to 9 million euros. The difference in costs between options largely stems from crude and product switching, which allows reductions in the cost of compliance. If ILUC accounting is introduced, the variations in compliance cost are amplified because it is assumed that the marginal cost (or saving) of additional (or fewer) tonnes of carbon savings will be greater. However, the difference between options is still only of the order of €50 million. The absolute costs for the ICF options compared to ICF's baseline are shown in Table 1.2). Note that in the iLUC options a much larger increase in emissions reductions compared to the FQD-free baseline is required to meet the target – this explains the much higher compliance cost for all options when iLUC is accounted.

Table 1.2. Total additional costs incurred by regulatory options ICF 0 (ICF baseline), ICF 1 (ICF defaults by feedstock) and ICF 3 (ICF hybrid, average defaults)

ABSOLUTE COSTS			NON-ILUC			ILUC		
			ICF 0	ICF 1	ICF 3	ICF 0	ICF 1	ICF 3
Transport energy demand		PJ	10,879	10,879	10,879	10,837	10,839	10,840
GHG emissions		Mt CO_2e	903	902	902	899	898	898
Final intensity (full joint reporting)		g/MJ	83.0	82.9	82.9	83.0	82.8	82.8
Compliance costs	biofuels	€m	-6	-6	-6	406	351	351
	UERs	€m	12	12	12	1211	1167	1167
	crude switching	€m	0	1	1	0	32	44
	product switching	€m	0	2	2	0	17	21
	total	€m	6	8	9	1618	1567	1584
Administrative costs*	low	€m	2	5 (15)	5 (18)	2	5 (15)	5 (18)
	average	€m	3	5 (15)	6 (23)	3	5 (15)	6 (23)
	high	€m	3	5 (16)	7 (28)	4	5 (16)	7 (28)
Total costs (with average administration costs)		**€m**	**9**	**13**	**15**	**1621**	**1572**	**1570**

1.1.3. Wood Mackenzie

Wood Mackenzie (2012) undertook an assessment for EUROPIA, the European refining industry association, of the "Impact of FQD Crude GHG Differentiation." In the study they considered a more disaggregated emissions accounting, with 10 example crude carbon intensities – ranging from about 2 gCO_2e/MJ to about 13 g CO_2e/MJ.

Wood Mackenzie claim that crude and product 'shuffling' is likely to be a cost effective way of reporting emissions reductions under the FQD. Specifically, they argue that 13 million tonnes of reportable emissions reductions would be achievable through crude and product shuffling. They find that this shuffling would also result in a 1.4 $MtCO_2e$ increase in shipping emissions. This would save the obligated parties (refiners) resources relative to cases where there is no crude differentiation. No consideration is made regarding whether crude oil carbon intensities or investment decisions would be affected by carbon pricing – the implication is that they would not, or that the possibility has not been assessed. Wood Mackenzie estimate that differentiated carbon defaults could generate an additional $2-3/bbl price differential between the lowest and highest carbon crudes available. The Wood Mackenzie study does not present any specific estimates of administrative cost or compliance cost, nor does it provide a transport cost estimate.

1.1.4. Assessment of Options 0 (baseline), 1 (elevated by fuel), 2 (average by fuel) and 3 (elevated by feedstock/MCON)

For this section, a model based on the ICF analysis is used to assess the administrative and compliance costs for each option, and the potential resulting change in emissions savings. For the baseline option, Option 0, the administrative cost (covering data tracking, verification and reporting) is expected to be of the order of €9 million per year. Because Option 0 would track any changes in the carbon intensity of the EU crude mix, if the underlying crude carbon intensity increases then that would have to be offset with additional carbon savings. For a 0.1 gCO_2e/MJ increase in average crude carbon intensity, the increased compliance cost to offset the 2 $MtCO_2e$ increase in carbon emissions is expected at €11 million in the case without iLUC accounting.

The administrative costs of Options 1, 2 and 3 are anticipated to be higher but similar. Depending on the level of opt-out reporting, the total cost to economic operators could be raised by up to €4.5 million, which is the expected extra cost of Option 3 in the high cost case. This representing the highest administrative burden as it is expected that it will involve a higher rate of actual value reporting.

While in Option 0 changes in compliance cost relate only to changes in the underlying crude mix, in Options 1, 2 and 3 compliance requirements could also be affected by some combination of suppliers selectively opting out to report actual data on their lowest carbon crudes and by (for Options 1 and 3) elevation of reportable default values. For Option 1 and 2, these are expected to reduce the overall compliance burden. For Option 3, elevated defaults are expected to increase the compliance burden, requiring an additional 6 $MtCO_2e$ of savings for a 20% elevation of default values (this assumes that the 2010 comparator against which the 6% carbon intensity reduction should be measured would be set on average carbon intensities). In all events, the costs are small compared to the overall compliance cost of the program, or to the price of oil.

As well as changing costs, hybrid reporting could introduce environmental benefits. Aside from increases n stringency of the target due to the use of elevated defaults, hybrid reporting could drive improvements in oil extraction efficiency, and investment shifts from higher to lower carbon intensity sources. It may also be seen as a step towards more ambitious regulation of crude carbon intensities in future. In contrast with potential benefits, there is also a risk of carbon leakage associated with hybrid reporting. Woods Mackenzie argued that crude switching could increase shipping emissions. While this evaluation seems to be based on an unreasonable assumption that all crude shipping routes are currently optimized for transport emissions, such increases are a risk of the policy. There is also a risk of carbon leakage due to crude switching, in the case that high carbon crudes are removed from the European crude mix only to be consumed in a different market instead.

1.2. Introduction

The FQD requires a 6% reduction in the carbon intensity of the European fuel slate by 2020. The Directive provides clear accounting rules for the use of biofuels to contribute to this target, but the accounting approach that should be used for fossil fuels supplied in Europe requires an additional implementing measure.

Depending on the implementing approach chosen, there may be additional compliance options that become available for fuel suppliers, additional emissions sources that must be offset and/or additional administrative costs to both economic operators and public authorities. For this task, existing studies on the potential costs of implementing fossil fuel accounting under the FQD are reviewed, and based on that review potential costs are assessed for the four implementation options specified in this report.

1.3. Studies

There are three primary sources that are considered for Task 1. The first is a report by CE Delft for the NGO Transport and Environment. The second, and the most important source for this report, is by ICF for the European Commission DG Clima. The third, and the source with the least detail provided, is a report by Wood Mackenzie for the European refining industry.

1.3.1. CE Delft

The 2012 CE Delft report "Oil reporting for the FQD An assessment of effort needed and cost to oil companies" provides an evaluation of the feasibility and cost of implementing the feedstock-based accounting system for crude oil under Fuel Quality Directive (FQD) that was proposed by the European Commission (2012). It was commissioned by the NGO Transport and Environment. Under the draft implementing measure, fuel suppliers would be required to identify the feedstocks used to produce fossil transport fuels – from a list of conventional oil, bitumen, kerogen, coal or gas, and each of these categories of fuel would have a default carbon intensity assigned to it. The proposed system of feedstock reporting would be similar to Option 0, the baseline in this report, with two major differences. For one, the Delft system would occur at a more aggregate level – Option 0 would include default values at the MCON level, thus providing substantially more resolution on conventional oil especially. Secondly, Option 0 would use reported data to adjust the estimated average carbon intensity of EU crude, but these figures would not be used to set individual obligated party compliance obligations.

Because both systems would require the imposition of a chain of custody to track the origins of crude oils, one might expect that the administrative costs would be similar for both. The data burden is not significantly different between the two, as in both cases, the challenge is essentially to set up chain of custody to track the origin of the oil. However, in the Delft study this reporting would create a disincentive to supply bitumen-derived fuel or other higher carbon fuels, as the higher carbon intensity associated with these fuels would need to be offset to achieve FQD compliance. This type of incentive is not present in Option 0, as there would be no requirement to offset the use of higher carbon MCONs.

Delft note that for much of the fuel produced in Europe, there would be no need to set up any additional chain of custody to track feedstock data – for crude oil shipped to refineries in Europe, the refiners would generally already know the origin (country and crude name), as well as the assay information. Identifying feedstock would require that those crude blends including natural bitumen or syncrude should be identified, but that should be relatively simple and would only be necessary for a small number of countries. Currently, in most cases national origin would be adequate to show that a crude did not contain natural bitumen. ICF (2013a) similarly observe that EU refineries should already have chain of custody in place for the basic information required to report origin and feedstock for crudes they refine.

For refined products, however, including final products, intermediates and feedstocks from the chemicals industry, Delft note that existing systems are not adequate to identify origin and feedstock. They also note that imports of final products and intermediates make a substantial contribution to EU fossil fuel supplies – equivalent to 20-25% of crude imports.

CE Delft make an estimate for the cost to refiners of implementing data tracking under FQD based on the number of full time employees (FTE) required to introduce and operate systems. Based on about 100 EU refineries, they estimate an annual cost of compliance incurred by the EU refinery sector of 35 to 64 million euros (see Table 1.3). This includes an initial one-year commitment of 5 to 15 FTEs to set up crude tracking systems, and an ongoing commitment of 1 to 4 FTEs to operate these systems. This assumes that each refinery will need to set up systems separately. They make a further rough estimate that the costs to traders will represent an additional 20%, giving a total range of 42 to 77 million euros. ICF (2013a) report that there are 129 refineries likely to be affected by the FQD, 39 of which would be outside of the EU. This is an additional 12 complex refineries and 19 simple refineries on top of those considered by Delft.[7] If costs scale linearly for this additional number, the Delft estimated range would be increased to 56 to 103 million euros. The costs estimated by ICF are discussed below in Section 1.3.2.

[7] Refinery complexity is a measure of a refinery's capacity to process lower sulfur crudes, meet precise product specifications (such as low sulfur fuel) and vary its product slate, for instance between petrol and diesel. Complexity can be measured with the Nelson complexity index.

Table 1.3. CE Delft's indicative cost estimate for development and maintenance of refinery tools for FQD tracing of crude origin and CO_2 intensity of fuel products

CALCULATION BASIS: ADAPTION EXISTING REFINERY OPTIMISATION TOOL				
	UNIT	COMPLEX	SIMPLE	TOTAL
Once-off Investment				
Min. Manpower required	FTE	10	5	
Max. Manpower required	FTE	15	7	
EU-27 Refineries	# of Refineries	30	68	98
Cost per FTE	thousand €	120	120	
Min. Once-off Investment – Refineries	million €	36	41	77
Max. Once-off Investment - Refineries	million €	54	57	111
Annualised Investment Cost				
Min. Once-off Invest – Depreciation/10 yr	million €	5	5	10
Max. Once-off Invest – Depreciation/10 yr	million €	7	7	14
Annual cost				
Min. Annual Manpower per Refinery (Reporting)	FTE	2	1	
Max. Annual Manpower per Refinery (Reporting)	FTE	4	2	
Min. Annual Cost Verification per Refinery	thousand €	150	75	
Max. Annual Cost Verification per Refinery	thousand €	300	150	
Min. Total Cost Annual – Refineries	million €	12	13	25
Max. Total Cost Annual – Refineries	million €	23	27	50
Min. Total cost Refiners + Traders	**million €**			**42**
Max. Total cost Refiners + Traders	**million €**			**77**

Source: CE Delft (2012), table 4

Delft note that these administrative costs would be modest compared to the greenhouse gas emissions reduction goals of the FQD. They calculate an expense of the order of 0.01 euro per barrel of crude.

CE Delft (2012) do not consider compliance costs associated with such a fossil fuel reporting methodology, nor do they undertake a quantitative assessment of possible fuel supplier responses to such a framework. They do not, for instance, consider the implications of potential fuel shuffling.

1.3.2. ICF "Impact Analysis of Options for Implementing Article 7a of Directive 98/70/EC (Fuel Quality Directive)" (August 2013)

In the context of the ongoing discussion over implementation of Article 7a of the FQD, the European Commission contracted ICF International to undertake a study comparing the implications of several options for fossil fuel accounting. The study is divided into three tasks:

- Development of a baseline;
- Cost benefit analyses of options;

- Competitiveness analysis.

The ICF study considers six accounting options as follows:

Table 1.4. Crude oil emissions accounting options from the ICF study

OPTION		METHOD TYPE	LEVEL OF DISAGGREGATION FOR UNIT GHG INTENSITY		UNIT GHG INTENSITY SPECIFIC TO FEEDSTOCK MIX OF:
			FUEL OR FEEDSTOCK	FEEDSTOCK CATEGORIZATION	
ICF 0, 'ICF baseline'		Default unit GHG intensity for the European Union	Fuel	N/A	EU
ICF 1, 'ICF defaults be feedstock'		Default unit GHG intensity for the European Union by feedstock	Feedstock	10 categories, specified in EC proposal (Note 2)	EU
ICF 2		Default unit GHG intensity for each Member State (MS)	Fuel	N/A	MS
ICF 3, 'ICF hybrid, average defaults'	Opt-In	Default GHG intensity for opt-in suppliers by each feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)	All suppliers choosing to Opt-In
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers choosing to Opt-out
ICF 4, 'ICF hybrid, elevated defaults'	Opt-In	Conservative default GHG intensity for the European Union by feedstock type	Feedstock	10 categories, specified in EC proposal (Note 2)	EU
	Opt-Out	Actual GHG intensity for each supplier or supplier group by feedstock type	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers
ICF 5		Actual GHG intensity for each supplier	Feedstock	Actual feedstocks per product per supplier	Supplier or group of suppliers

For clarity and brevity, these options from the ICF study will henceforth be referred to as 'ICF 1', 'ICF 2', 'ICF 3', etc., and sometimes also by the following shorthand descriptions: 0 is the 'ICF baseline', ICF 1 is 'ICF, defaults by feedstock', ICF 3 is 'ICF hybrid, average defaults' and ICF 4 is 'ICF hybrid, elevated defaults'.

These options do not match up precisely with the three options identified by the Commission for this study, but there are clearly similarities. ICF 1 reflects many of the characteristics of Option 0 (baseline). One difference is that while Option 0 specifies 'crude/feedstock trade names' (MCONs) as the level of disaggregation, ICF 1 disaggregates only to the level of feedstock. These feedstocks are: conventional crude; oil shale (kerogen); Liquefied Petroleum Gas (LPG), Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) from any fossil sources; coal converted to liquid fuel ((with and without Carbon Capture and Storage (CCS)); gas to liquids; hydrogen from natural gas (steam reforming); hydrogen from coal; hydrogen from coal with CCS; and waste plastic. The second difference is that in Option 0, reported carbon intensities are used to set the EU average crude carbon intensity, but not to set supplier specific obligations. In ICF

1, the reported carbon intensities would directly influence supplier compliance obligations. This is very much similar to the reporting option considered by Delft.

ICF 4 (ICF hybrid, elevated defaults) in the ICF paper is similar to Option 1 (elevated by fuel) and 3 (elevated by feedstock/MCON) in this study – both allow opt-in/opt-out reporting based on elevated (conservative) default values. The difference is that for this study we consider elevated default values at the fuel level (Option 1) or the MCON level (Option 3). The ICF study instead considered elevated default values at the feedstock level as per the list above, which provides an intermediate level of specificity. Because most transport fuel is produced from conventional oil, ICF Option 4 is considered closer to this report's Option 1 (where all fuel from conventional oil has a single default) than to Option 3 (where conventional oil defaults would be disaggregated). For opt-out suppliers, however, ICF did assume reporting by specific crude, distinguished at least to the national level. This gives a list of crudes and a set of carbon intensities that differ from the crudes presented in this report, but the principle is comparable. ICF 3 (ICF hybrid, average defaults) study is close to Option 2 (average by fuel) here, and differs in the same way that ICF 4 differs from Option 1 here. None of ICF 5, ICF 0 or ICF 2 are reflected in the options considered here. We will therefore focus on the analysis of ICF 1, 3 and 4. ICF report that they were asked to analyze the cost implications of ICF 1, 2 and 3 in detail – therefore, the cost implication of ICF 4 must be inferred from the analysis of ICF 3. These associations are shown in Table 1.5.

Table 1.5. Comparison of options from ICF study to options in this study

ICF OPTION	CLOSEST OPTION FROM THIS STUDY	DIFFERENCES
ICF 0 (ICF baseline)	n/a	
ICF 1 (ICF defaults by feedstock)	Option 0	ICF 1 disaggregates by feedstock, not MCON. ICF 1 requires suppliers to offset high-CI feedstocks
ICF 2	n/a	
ICF 3 (ICF hybrid, average defaults)	Option 2	ICF 3 uses elevated feedstock CIs; Option 2 uses elevated fuel type CIs
ICF 4 (ICF hybrid, elevated defaults)	Option 1	ICF 4 uses elevated feedstock CIs; Option 1 uses elevated fuel type CIs
	Option 3	ICF 4 uses elevated feedstock CIs; Option 3 uses elevated MCON CIs
ICF 5	n/a	

1.3.2.b. Compliance cost

The compliance cost analysis by ICF (2013a) is based on marginal abatement cost (MAC) curves for compliance options (upstream emissions reductions, biofuels, and any options for a supplier to report a lower fossil fuel carbon intensity such as crude shuffling). The data on upstream emissions reduction costs is based on assessing the recorded cost of past flare reduction projects – no other upstream emissions reductions are included. The value of recovered gas is offset against the cost of the projects. The marginal abatement cost of compliance with biofuels is based on the difference between the cost of the biofuel and the displaced fossil fuel, and the difference in carbon intensities between the two. ICF's central scenario assumed that there would be no iLUC factors introduced into the FQD's carbon accounting framework, but they also considered a sensitivity in which iLUC accounting for biofuels would be implemented. The introduction of iLUC factors eliminates some fuel pathways as options for FQD compliance (as they would not deliver any carbon savings). It therefore has the effect of pushing marginal compliance outcomes to the right along the cost curve.

The compliance costs estimated to meet the 6% carbon intensity reduction target of the FQD in each relevant option are shown in Table 1.6. In the case that there is no iLUC accounting, ICF anticipate only moderate compliance costs whichever of the options is implemented. ICF 1 (ICF defaults by feedstock) shows a slight increase in compliance costs of 2 million euros in 2020 compared to ICF 0. This reflects the additional cost of crude and product switching that is expected under ICF 1. Crude, feedstock or product switching (sometimes referred to as shuffling) are compliance options for the FQD that are available in any system with some degree of disaggregation of default carbon intensity values, or with actual carbon intensity value reporting. Switching happens when an operator preferentially chooses to supply fuels produced from crudes/feedstocks with lower reportable carbon intensities (or to preferentially supply fuel types with lower reportable carbon intensities).

ICF 3 (ICF hybrid, average defaults) shows a more significant cost change – a saving of 5 million euros in 2020 due to reduced requirements to supply biofuels. This saving reflects the expectation that under hybrid reporting, those fuel suppliers already processing lower carbon intensity crude oils would be able to report this and reduce their compliance obligations proportionately, while those suppliers with a high carbon intensity would still be able to use the default. For the lower carbon intensity fuel suppliers, this additional reporting would be relatively cheap compared to the alternative compliance routes available to them. ICF note that if the default emissions were instantly corrected for suppliers opting in to use the defaults, then this advantage to opt-out suppliers would be balanced exactly by an increased compliance burden on opt-in suppliers. However, because ICF assume an annual iterative process in which default values would always represent the previous year's fuel supply, there is a slight effective weakening of the target under Option 3 (elevated by feedstock/MCON), and thus the saving from reduced biofuel use.

In the case that iLUC emissions are accounted, the picture is somewhat different because of the need for alternative compliance strategies to make up for a reduced biofuel supply. The baseline includes enough biofuel to allow compliance with the existing Renewable Energy Directive (RED) target, but this is inadequate to deliver a 6% carbon intensity reduction on its own. The anticipated carbon intensity (ignoring iLUC and in the absence of the FQD) of the 2020 fuel mix is 83.76 gCO_2e/MJ, above the 83.00 gCO_2e/MJ target. With iLUC, this becomes 87.17, substantially above the target. Additional carbon emissions reductions are therefore required in either case – but far more if iLUC is accounted. ICF expect that upstream emissions reductions will offer the lowest cost carbon intensity reductions, and in the non-iLUC case will provide most additional savings. However, in ICF 1 and ICF 3 crude and product switching are also considered to be possibilities to meet the FQD target and are expected to occur. The additional cost of FQD compliance is relatively modest – projected between 6 and 9 million euro once savings from reduced biofuel demand (due to reduced overall fuel demand) are accounted. In the iLUC case, however, the need for additional savings is much greater. As well as a significant requirement for additional low carbon biofuels, much larger expenditures (over 1 billion euros) are required on upstream emission reductions (UERs) from reduced venting and flaring.

Within the two cases (iLUC and non-iLUC), the choice of fossil fuel carbon intensity reporting option is projected to have a relatively modest effect on total cost. Absolute costs for the non-iLUC costs range from 6 to 9 million euros (Table 1.6). In the iLUC case, adding fossil fuel CI reduction options (crude switching) through ICF 1 or ICF 3 actually help to reduce the cost of the policy – adopting the ICF 3 hybrid reporting regime would reduce costs by 34 million euros, while ICF 1 would reduce costs by about 50 million euros (against total compliance costs of around 1.6 billion euros).

Table 1.6. Absolute compliance costs for FQD under various options

ABSOLUTE COSTS			NON-ILUC			ILUC		
			ICF 0	ICF 1	ICF 3	ICF 0	ICF 1	ICF 3
Compliance costs	biofuels	M€	-6	-6	-6	406	351	351
	UERs	M€	12	12	12	1211	1167	1167
	crude switching	M€	0	1	1	0	32	44
	product switching	M€	0	2	2	0	17	21
	total	**M€**	**6**	**8**	**9**	**1618**	**1567**	**1584**

Source: ICF (2013a)

ICF assume that emissions savings can be achieved by feedstock switching under either ICF 1 (ICF defaults by feedstock) or ICF 3 (ICF hybrid, average defaults). They consider only switching between feedstock categories (Table 1.7) – a more disaggregated approach to conventional crude would make more savings options available. ICF assume that there would be no opportunity to switch from natural bitumen to conventional crude under ICF 3. Presumably, this would be because given ICF's assumptions any refiner of natural bitumen would be expected to opt-in to report default values rather than to switch feedstocks and then opt-out. We note however, that the full explanation for the reported zero opportunity is not completely explicit from the ICF report, as we understand it.

Table 1.7. Abatement potential of feedstock switching

SENSITIVITY	SCENARIO	ABATEMENT POTENTIAL (MT CO_2) FROM SWITCHING FEEDSTOCK CATEGORIES TO CONVENTIONAL			ABATEMENT POTENTIAL (MT CO_2) FROM SWITCHING PRODUCT IMPORTS TO CONVENTIONAL	
		FROM NATURAL BITUMEN	FROM OIL SHALE	FROM CTL	FROM GTL	FROM NATURAL BITUMEN
Non-ILUC	ICF 1	4.6	0.1	1.5	0.5	0.4
	ICF 3 opt in	0	0.1	1.5	0.5	0.4
ILUC	ICF 1	4.6	0.3	1.6	0.5	0.4
	ICF 3 opt in	0	0.1	1.6	0.5	0.4

Source: ICF (2013a)

1.3.2.c. Administrative costs

The administrative costs modeled by ICF include monitoring, reporting and verification (MRV) costs for both suppliers and public authorities. For suppliers, under both Option 1 (elevated by fuel) and Option 3 (elevated by feedstock/MCON) the costs include the development of internal data tracking protocols, the cost of having a single European assurance standard developed, the cost of internal and external verification in line with such an assurance standard, the development of chain of custody for data about traded refined products, and the costs of monitoring and verification of upstream emissions reduction projects.[8] For ICF 3 (in which opt-out suppliers would have an enhanced MRV burden to report their own actual data) there are also costs associated with developing systems to manage supplier specific data and calculate supplier specific carbon intensities. The costs to suppliers of this opt-out calculation are expected to vary based on the system used to undertake the calculation. The most expensive case according to ICF is where suppliers develop and operate their own engineering models of lifecycle stages.[9] A similar cost is associated with developing their own specific carbon intensities based on actual measurements. However, the cost would be much reduced if suppliers were able to use LCA models already populated with default values. The use of OPGEE as the preferred model for LCA calculations, as considered in this report, would be closest to this third, lowest cost, case. The total annual costs to EU fuel suppliers for each element of MRV identified by ICF are shown in Table 1.8.

[8] In the case of UERs, the costs are modelled on the cost of implementing CDM emissions reduction projects.
[9] We do not consider it likely that all suppliers would develop separate tools, and it would be very challenging to regulate and quality control such a diverse set of approaches. Even if the option to develop multiple models was permitted, it is more likely that a small number of platforms would be developed and marketed to several suppliers.

Table 1.8. Administrative costs for crude oil reporting in ICF (2013a)

MRV ACTIONS		REFERENCE ACTOR	NUMBER OF ACTORS	TOTAL ANNUAL COST FOR THE EU (ICF 1)		TOTAL ANNUAL COST FOR THE EU (ICF 3)	
				Low	High	Low	High
Regulation Review		All suppliers	904	€ 117,000	€ 117,000	€ 117,000	€ 117,000
LCA calculation	**own measurement**	⅓ opting out producers	19	-	-	€ 742,600	€ 3,050,800
	engineering estimates	⅓ opting out producers	19	-	-	€ 896,300	€ 2,810,600
	existing model	⅓ opting out producers	19	-	-	€ 147,200	€ 704,200
Verification and validation cost		Opting out refineries	56	-	-	€ 144,700	€ 691,800
Development of internal tool / spread sheet		Simple refinery	87	€ 30,000	€ 60,100	€ 30,000	€ 60,100
		Complex refinery	42	€ 29,000	€ 58,000	€ 29,000	€ 58,000
Maintaining internal tool / spread sheet		Simple refinery	87	€ 1,583,400	€ 1,583,400	€ 1,583,400	€ 1,583,400
		Complex refinery	42	€1,528,800	€1,528,800	€ 1,528,800	€ 1,528,800
Verification - development of a EU harmonised assurance standard		All EU refineries	1	€ 2,000,000	€ 3,000,000	€ 2,000,000	€ 3,000,000
Internal and external verification		Simple refinery	87	€ 91,400	€ 91,400	€ 51,500	€ 51,500
		Complex refinery	42	€ 88,200	€ 88,200	€ 50,400	€ 50,400
Management and transfer of data by fuel traders and verification of this process		Fuel traders active in the EU	775	€ 9,100,000	€ 9,300,000	€ 11,470,300	€ 18,626,300
UER Projects – pre-registration cost		UER projects	4	€ 15,300	€ 57,500	€ 15,300	€ 57,500
UER Projects – post registration costs		UER projects	4	€ 31,000	€ 62,000	€ 31,000	€ 62,000

The largest contribution to the total cost comes from the imposition of chain of custody requirements on fuel traders to refined product flows. ICF reference CE Delft (2012) as the basis for this estimate. The Delft assumption is that total cost incurred by traders would equal 20% of the total cost incurred by refineries. Hence, ICF state that “this assumption has been confirmed by ICF experts and will therefore be followed in the developed estimates.” However, examination of the cost values reported in the ICF tables (from table 6.18 onwards), makes it clear that ICF have in fact not used the same assumption as Delft. For ICF 1, for instance, the maximum total cost of MRV across the EU refineries (not including UER verification) is reported as 6.5 million euros. The cost from trader verification, in contrast, is reported as 9.1 – 9.3 million euros. Based on the Delft formula applied to all costs borne by refiners, the total cost to traders should be only around 1.3 million euros.

The primary reason for the discrepancy is that ICF have applied the 20% assumption to the cost per individual operator, rather than to the cost to traders overall. Because ICF identify several more traders than refiners (775 compared to 129 refineries), the total cost to traders comes out as much more than 20% of the total cost to refiners.[10] ICF stated via email that this approach was adopted because Delft's report does not identify the total number of traders, and thus they preferred to consider an individual operator rather than the group of operators. Notwithstanding this confirmation, based on the text in the ICF and Delft reports there seems to be no solid basis for an assumption that individual traders will incur costs of 20% of the average cost to individual refiners. Given that the ICF report clearly states that the Delft assumption is reasonable as given, and that the Delft assumption clearly refers to total cost rather than cost per operator, it seems appropriate to adjust the ICF cost estimates to reflect the assumption that costs to traders in total will be 20% of the cost to refiners in total. Adjusting in this way, but including as a term the 20% calculation, the cost of developing a harmonized EU standard[11] gives a revised estimate of the cost to traders of 700,000 to 800,000 euros. Table 1.9 shows the detail of the revised calculation for the case of ICF 1 (ICF defaults by feedstock). This adjustment reduces total estimated costs by about 8 million euros, more than 50%.

It is worth noting that for 775 traders, this implies an annualized cost of around 1,000 euros per year per trader to implement reporting by feedstock, so only a few days of labor per year. This is low compared to the cost numbers in both CE Delft and ICF, and represents a minimal time commitment for each trader. That said, it sounds potentially reasonable based on the assumption that a robust chain of custody system is in place and that traders could pass data along the supply chain without additional checks (i.e. that the burden of verification would be placed almost entirely on refiners). The ICF estimate of cost to refiners includes costs to 39 refiners outside the EU that ICF estimate are supplying diesel into the EU market. It is hence reasonable to assume that the cost of the supply chain is already included in the ICF estimates up to the point at which traders would take ownership of a given batch of fuel. However, this level of expenditure would be inadequate to cover detailed third party audit of supply chain data for any significant large fraction of traders.

Having reassessed the cost of verification to traders, the development of a pan-European harmonized assurance standard is the next largest cost reported in the ICF study, at €2 – 3 million. This number also requires adjustment however, as it represents a one off cost rather than an annual cost, despite being presented in the annual cost column of ICF's table. Using the same cost accounting as ICF (10-year equivalent annual with a 4% assumed interest rate), the annualized cost of developing a harmonized assurance standard is only 250,000 to 350,000 euros.

It is pertinent to note that the cost estimate from ICF is based on specific assumptions by ICF that such a standard would be developed in accordance with the International Auditing and Assurance Standard Board (IAASB), assumptions

[10] The numbers are further complicated by the way that ICF have included and excluded rows from their calculation, making it difficult to reproduce their result without additional input. The cost of developing a harmonized EU standard is excluded, but the cost of developing and maintaining an internal spreadsheet is summed across a simple **and** a complex refinery, rather than choosing one (or taking the average of the two.

[11] As noted above, this was excluded from the original ICF calculation, but for consistency the Delft report should be included.

that are taken in turn from Delft. If this process was led by the European Commission rather than delegated through Member States to the fuel suppliers, this cost could be different and could be borne by other actors. It is also entirely possible that in practice any assurance standard might be developed outside of the IAASB framework. This cost assessment should therefore be understood as an exemplar of the possible cost in practice.

Table 1.9. Calculation of revised estimate of cost to traders of implementing the ICF 1 option (ICF defaults by feedstock)

MRV ACTIONS	LOW	HIGH
Regulation Review	€ 117,000	€ 117,000
Development of internal tool / spread sheet	€ 59,000	€ 118,100
Maintaining internal tool / spread sheet	€ 3,112,200	€ 3,112,200
Verification - development of a EU harmonised assurance standard	€ 246,600	€ 369,900
Internal and external verification	€ 179,600	€ 179,600
Total cost to refiners (excluding UER verification)	**€ 3,714,400**	**€ 3,896,700**
Revised cost of management and transfer of data by fuel traders and verification of this process (20% of total for refiners)	€ 742,900	€ 779,300

Given these adjustments, the final estimated costs for the EU and per operator, and associated low and high estimates of total costs, are shown for ICF 1 and ICF 3 in Table 1.10. For ICF 1, the total cost is in the range 4.5 – 5 million euros. For ICF 3, it ranges from about 5 to 7 million euros. The maximum anticipated cost to a single economic actor is around 140,000 euros per annum for a complex refiner, opting-out in order to report its own carbon intensity data and registering upstream emissions reduction projects. These costs are very modest compared to the overall cost of compliance with the FQD, or compared to the cost of a barrel of oil (5 million euros would correspond to less than one eurocent per barrel of European demand.

Table 1.10. EU and per-operator costs of MRV of fossil fuel carbon intensity data for the FQD in options ICF 1 (ICF defaults by feedstock) and ICF 3 (ICF hybrid, average defaults)

MRV Actions		Reference actor	Number of actors	Total annual cost for the EU (ICF 1)		Total annual cost for the EU (ICF 3)		Per operator annual cost (ICF 1)		Per operator annual cost (ICF 3)	
				Low	High	Low	High	Low	High	Low	High
Regulation Review		All suppliers	904	€ 117,000	€ 117,000	€ 117,000	€ 117,000	€ 129	€ 129	€ 129	€ 129
LCA calculation (options)	own measurement	Opting out refineries	19	-	-	€ 247,500	**€ 1,016,900***	-	-	€ 13,000	**€ 53,500**
	engineering estimates	Opting out refineries	19	-	-	€ 298,800	€ 936,900	-	-	€ 15,700	€ 49,300
	existing model	Opting out refineries	19	-	-	**€ 49,100***	€ 234,700	-	-	**€ 2,600**	€ 12,400
Verification and validation cost		Opting out refineries	56	-	-	€ 144,700	€ 691,800	-	-	€ 2,600	€ 12,400
Development of internal tool / spread sheet		Simple refinery	87	€ 30,000	€ 60,100	€ 30,000	€ 60,100	€ 345	€ 690	€ 345	€ 690
		Complex refinery	42	€ 29,000	€ 58,000	€ 29,000	€ 58,000	€ 690	€ 1,400	€ 690	€ 1,400
Maintaining internal tool / spread sheet		Simple refinery	87	€ 1,583,400	€ 1,583,400	€ 1,583,400	€ 1,583,400	€ 18,200	€ 18,200	€ 18,200	€ 18,200
		Complex refinery	42	€ 1,528,800	€ 1,528,800	€ 1,528,800	€ 1,528,800	€ 36,400	€ 36,400	€ 36,400	€ 36,400
Verification - development of a EU harmonized assurance standard		All EU refineries	90	€ 246,600	€ 369,900	€ 246,600	€ 369,900	€ 2,700	€ 4,100	€ 2,700	€ 4,100
Internal and external verification		Simple refinery	87	€ 91,400	€ 91,400	€ 51,500	€ 51,500	€ 1,100	€ 1,100	€ 600	€ 600
		Complex refinery	42	€ 88,200	€ 88,200	€ 50,400	€ 50,400	€ 2,100	€ 2,100	€ 1,200	€ 1,200
Management and transfer of data by fuel traders and verification of this process		Fuel traders active in the EU	775	€ 742,900	€ 779,300	€ 766,100	€ 1,105,600	€ 960	€ 1,000	€ 990	€ 1,400
UER Projects – pre-registration cost		UER project participant	4	€ 15,300	€ 57,500	€ 15,300	€ 57,500	€ 3,800	€ 14,400	€ 3,800	€ 14,400
UER Projects – post registration costs		UER project participant	4	€ 31,000	€ 62,000	€ 31,000	€ 62,000	€ 7,800	€ 15,500	€ 7,800	€ 15,500
Total cost				**€ 4.5 m**	**€ 4.8 m**	**€ 4.6 m**	**€ 6.8 m**				

**The low estimate for total cost includes the lowest burden LCA approach (use of existing models), while the high estimate includes the highest burden LCA approach (actual measurement). ICF in their report assumed that 1/3 of opt-out suppliers would use each approach, but we consider it much more likely that all suppliers will be required to use the same system.*

1.3.2.d. Costs to public authorities

Public authorities would experience additional MRV costs in handling and verifying data reported by suppliers, but these costs are essentially negligible compared to the costs to suppliers according to ICF's assessment. The total cost is around 50,000 euro per year in either ICF 1 (ICF defaults by feedstock) or ICF 3 (ICF hybrid, average defaults). ICF's assessment assumes that the data tracking, collation and verification burden falls very largely on the suppliers, and hence that the responsibility of the Member States would be restricted to gathering this data and passing it to the European Commission. In reality, the administrative burden for member states is likely to be heavily dependent on:

- the way that FQD reporting is set up;
- the extent to which crude oil carbon intensity reporting can be integrated into existing systems for handling biofuel reporting under RED/FQD; and
- the extent to which the European Commission takes central responsibility for providing guidance to suppliers vs. relying on the member states to produce and maintain guidance documentation etc.

The costs that have been reported by existing biofuel regulators are discussed later in Section 1.5.2.

Table 1.11. MRV costs for public authorities

MRV ACTIONS	REFERENCE ACTOR	NUMBER OF ACTOR	TOTAL ANNUAL COST FOR THE EU (ICF 1)	TOTAL ANNUAL COST FOR THE EU (ICF 3)
Periodical update of data required for the calculation	EC	1	€ 1,233	€ 10,000
MS - Gathering and reporting data to the EC	27 MS	/	€ 8,007	€ 8,007
			€ 11,932	€ 11,932
EC – Processing and analysis of data	EC	1	€ 4,000	€ 4,000
			€ 5,500	€ 5,500
Total cost			**€ 40,672**	**€49,439**

1.3.2.e. Total additional cost incurred

Table 1.12 shows the total additional costs that would be incurred related to fossil fuel carbon intensity reporting under FQD for three regulatory options (ICF 0, ICF 1 and ICF 3), both with and without the implementation of iLUC factors. In the case that iLUC accounting is not introduced, compliance costs and administrative costs are on the same scale. In the non-iLUC case, compliance costs are much higher.

Table 1.12. Total additional costs incurred by regulatory options ICF 0 (ICF baseline), ICF 1 (ICF defaults by feedstock) and ICF 3 (ICF hybrid, average defaults)

ABSOLUTE COSTS			NON-ILUC			ILUC		
			ICF 0	ICF 1	ICF 3	ICF 0	ICF 1	ICF 3
Transport energy demand		PJ	10,879	10,879	10,879	10,837	10,839	10,840
GHG emissions		$MtCO_2e$	903	902	902	899	898	898
Final intensity (full joint reporting)		g/MJ	83.0	82.9	82.9	83.0	82.8	82.8
Compliance costs	biofuels	€m	-6	-6	-6	406	351	351
	UERs	€m	12	12	12	1211	1167	1167
	crude switching	€m	0	1	1	0	32	44
	product switching	€m	0	2	2	0	17	21
	total	**€m**	**6**	**8**	**9**	**1,618**	**1,567**	**1,584**
Administrative costs*	low	€m	2	5 (15)	5 (18)	2	5 (15)	5 (18)
	average	€m	3	5 (15)	6 (23)	3	5 (15)	6 (23)
	high	€m	3	5 (16)	7 (28)	4	5 (16)	7 (28)
Total costs (with average administration costs)		**€m**	**9**	**13**	**15**	**1,621**	**1,572**	**1,570**

Source: ICF (2013, Table 6.30)
**ICCT's adjusted values (adjusting the verification cost to traders and annualizing the development of a harmonized assurance scheme as detailed above) are show, with original ICF values in parentheses.*

1.3.3. Wood Mackenzie

Wood Mackenzie (2012) undertook an assessment for EUROPIA, the European refining industry association, of the "Impact of FQD Crude GHG Differentiation." Unlike the CE Delft study, which followed strictly the proposal put forward in 2012 by the Commission, Wood Mackenzie considered a more disaggregated emissions accounting, with 10 example crude carbon intensities. This would therefore be more comparable to Option 0, although with far fewer crude categories than would be given by full MCON differentiation, but with suppliers held accountable for their specific crude oil carbon intensities. The well-to-wheels emissions of the 10 example crudes span a range from about 2 gCO_2e/MJ to about 13 g CO_2e/MJ. Oil sands crude produced using steam assisted gravity drainage (SAGD) are assigned the 3rd highest carbon intensity of ten in this range – the rest represent notional conventional crudes, it is not explicit what pathways the highest carbon intensity crudes represent.

On compliance cost, Wood Mackenzie find that crude and product 'shuffling' (that is, replacing higher carbon crudes with lower carbon crudes as feedstocks for EU refineries) is likely to be the most cost effective way of reporting emissions reductions under the FQD. This contrasts with ICF (2013a) who find that biofuels and upstream emissions reductions may be the lowest cost marginal compliance opportunities. Specifically, Wood Mackenzie argue that 13 million tonnes of reportable emissions reductions would be achievable through crude and product shuffling under the carbon intensity accounting system they envision. They believe that this level of shuffling would be associated with a 1.4 million tonne increase in CO_2e emissions from shipping. It is assumed that there would be no change to the overall global crude mix.

Wood Mackenzie estimate that such a scheme could generate an additional $2-3/bbl price differential between the lowest and highest carbon crudes available. These are EU prices, and the difference would presumably be much more modest on the world market as a whole. They find that the potential for cost increases for refiners is in the range 2-11 eurocents per liter of refined product, and that this will negatively affect all EU refineries. Because of this increased cost to European refiners, Wood Mackenzie state that earnings will be impacted by both the higher costs themselves, and by reduced utilization because of lost competitiveness compared to refiners elsewhere in the world. It is not entirely clear from the Wood Mackenzie report whether the policy framework that they model is expected to be applied to non-EU refiners. The implication from the strong impact in competitiveness that they describe is that the policy they model may not impose reporting obligations on non-EU refineries, which would differentiate it from the policy options assessed by CE Delft (2012) or by ICF (2013a), or the options considered here. It seems unlikely that the European institutions would impose crude carbon reporting only on European refiners and not on imports. However, it is also possible that Wood Mackenzie are assuming that carbon intensity reporting rules would indeed apply outside the EU, but that non-EU refiners would face less local competition for lower carbon intensity crudes and therefore experience more modest price differentials.

The Wood Mackenzie study does not present any specific estimates of administrative cost or compliance cost, nor does it provide a transport cost estimate to go with the estimated increase in shipping emissions.

1.4. Fraud prevention

CE Delft (2012) notes that, "the [FQD] system might be vulnerable for fraud as intermediates and final products can be blended easily and markets are volatile." Without adequate verification systems in place, any fossil fuel accounting system that gives value to lower carbon crudes and fuels would be at risk of fraud, especially as chemically there is no way to reliably distinguish between high carbon- and low carbon intensity oils.[12] It is possible that modern analytical chemistry techniques could be used to

[12] It is possible to distinguish heavy from light crudes, but while this may in some cases correlate to carbon intensity (such as oil sands), it is not a robust rule.

identify crudes by trace elements or other chemical properties of the crudes. Fingerprinting techniques of this sort have been used to identify the source of oil in spills, and fingerprinting services are offered[13] to assist oil companies in reservoir analysis and leak identification. Certainly, it should be possible to rule out some origins for particular oil samples using analytical chemistry techniques, given the existence of databases of reservoir sample data. Additional research would be required to establish whether such techniques have potential to be valuable in this context, and the possibility of crude oils being blended in varying ratios may make the application of such techniques more difficult.

Given the lack of proven techniques to identify oils at the point of entry to the refinery, regulating upstream emissions intensities would require robust chain of custody to be put in place to allow carbon data to track oil right the way through the supply chain. The CE Delft and ICF studies assume that data assurance for FQD fossil fuel carbon intensity reporting would be managed by the International Auditing and Assurance Standards Board, and that the cost of this process will be passed from Member States (who are responsible for verification under FQD) to economic operators.

While the development of an IAASB standard is one approach to verification under FQD, it is far from clear that this would in fact be adopted by the Member States in practice. The experience of the implementation of the RED for biofuels suggests that Member States may not have the systems in place to come to agreement on a single uniform approach to verification across the Union. For biofuels, the national administrators have relied on a mix of verification through third party voluntary schemes, auditor's assurance and direct regulatory checks that varies from state to state. The challenges of monitoring carbon intensity data for fossil fuels are similar to the challenges for biofuels. In each case, material may be transported large distances, potentially moving through several blending hubs en route to its final destination. The type of mass balance systems implemented for biofuel monitoring, under which there are clear rules for the allocation of carbon intensity data within mixed fuel batches, could also be applied to oil shipments. Tracking carbon intensities through the refined product/intermediate supply chain could be potentially more challenging, as for at any point in the chain where chemical reactions occur a simple mass balance approach might not provide the correct assignation of emissions intensity data.

It would be important to have rigorous chain of custody in place right from field to refinery gate, in order to ensure that information was correctly reported. Elements of an assurance scheme could include:

- comprehensive review of chain of custody paperwork by independent verifiers;
- random checks of upstream data by independent verifiers;
- random company audits by national administrators;

[13] E.g. by SGS http://www.sgs.com/Oil-Gas/Upstream/Reservoir-and-Production-Fluids-Analysis/Fixed-Laboratory-Services/Oil-Fingerprinting.aspx

- satellite verification of operations visible from space (e.g., flaring with current infrared satellites, perhaps methane plumes from venting with future satellites);
- appropriate penalties for lack of due diligence by operators.

The implementing legislation for Article 7a should provide clear guidance on verification to Member States. Any Member state failing to adequately enforce or implement chain of custody rules would potentially undermine the environmental goals of the FQD.

1.4.1. Differences between Options

Under Options 1 (elevated by fuel) or 2 (average by fuel), default values will be allocated by fuel type. For opt-in suppliers, there would therefore be minimal scope for fraud under these options, and the burden of verification would fall primarily on opt-out suppliers. For opt-out suppliers, the potential gains from incorrect reporting of MCONs would be significant under either of these options. For instance, reporting that a refinery was running entirely on lower-than-average carbon-intensity crude could generate significant FQD compliance cost savings for the facility. This price signal would also travel upstream, as low carbon-intensity batches of crude would take on extra value in the European market. Traders would therefore have an incentive to market crude as low-CI, even if the refiners themselves look to act in good faith. The incentive to fraud would be greater in Option 1 than Option 2 because of elevated default reporting.

Under Option 3 (elevated by feedstock/MCON), there could be incentives for fraud both for opt-in *and* opt-out suppliers. Reporting the wrong MCON to achieve a preferred default value would have financial value, as would falsifying the actual value for an MCON. Of course, it is important to bear in mind that the increased incentive to fraud runs in parallel with an increased incentive to take action in line with policy objectives – for instance by avoiding high carbon crudes or by reducing carbon intensity at the oil field.

1.5. Comparison of options

Having reviewed the major existing studies on the likely costs of implementing fossil fuel carbon intensity reporting under Article 7a of the FQD, this section uses this data to estimate the potential costs of implementing Options 0 to 3.

1.5.1. Administrative costs to operators

The baseline option, 'Option 0', for this report is for suppliers to report default emissions values for each MCON that they refine or import (or that was processed into imported refined product). This option would involve the following:

- Refiners

- Record the names, origins and basic characteristics (API and sulfur content) of all crude oil entering the refinery.
- Require data and chain of custody guarantees for the constituent crudes of all intermediates entering the refinery as feedstock.[14]
- Apply due diligence to the verification of the veracity of this data.
- Implement chain of custody to allow mass-balance based reporting[15] of the constituent crudes of any intermediate products sold on by the refinery.
- For all road fuels and fuels for non-road mobile machinery for which the refiner is designated as the responsible party under the FQD, report to the authority appointed by the relevant member state the constituent crudes used to produce that fuel, based on a specified mass balance calculation. This reporting should include crude name, point of origin and basic characteristics (API and sulfur content).
- For all road fuels and fuels for non-road mobile machinery leaving the refinery for which a third party will become the responsible party under the FQD, transfer to that third party records of the constituent crudes used to produce that fuel, based on a specified mass balance calculation, along with guarantees of the chain of custody.

- Importers/traders of refined product
  - Require data and chain of custody guarantees for the constituent crudes of all imported refined products.
  - For all road fuels and fuels for non-road mobile machinery for which the importer is designated as the responsible party under the FQD, report to the authority appointed by the relevant member state the constituent crudes used to produce that fuel, based on a specified mass balance calculation. This reporting should include crude name, point of origin and basic characteristics (API and sulfur content).
  - For all imported road fuels and fuels for non-road mobile machinery for which a third party will become the responsible party under the FQD, transfer to that third party records of the constituent crudes used to produce

[14] For some feedstocks, such as material transferred to refineries for the chemicals industry, it may be unduly burdensome to demand full mass balance assessment of constituent feedstocks – or lifecycle assessment of all chemical processes involved in production of those materials. For the purposes of this report, we shall assume that reporting is only required for intermediate materials that remain within the petroleum supply chain, as distinct from the chemicals supply chain.
[15] Examples of mass balance rules are available in biofuel reporting regulations.

    - that fuel, based on a specified mass balance calculation, along with guarantees of the chain of custody.

- Any other party designated by a member state as responsible for compliance with the carbon intensity reduction target under FQD
    - For all road fuels and fuels for non-road mobile machinery for which they are designated as the responsible party under the FQD, report to the authority appointed by the relevant member state the constituent crudes used to produce that fuel, based on a specified mass balance calculation. This reporting should include crude name, point of origin and basic characteristics (API and sulfur content).

- Oil producers
    - Ensure that data on crude origin and basic crude characteristics is passed down the supply chain.[16]

- Non-EU refiners shipping refined product/intermediates to the EU
    - Record the names, origins and basic characteristics (API and sulfur content) of all crude oil entering the refinery.
    - Require data and chain of custody guarantees for the constituent crudes of all intermediates entering the refinery as feedstock.[17]
    - Apply due diligence to the verification of the veracity of this data.
    - Implement chain of custody to allow mass-balance based reporting of the constituent crudes of any intermediate or refined products sold into the European market by the refinery.

These reporting and data tracking requirements are common to all the other options as well, as each of Options 1, 2 and 3 would require this type of reporting from opt-in suppliers, while the data management requirements on opt-out suppliers would include and expand on this.

As noted above, Option 0 (baseline) is somewhat similar to the ICF 1 option (ICF defaults by feedstock) considered by ICF in the Impact Analysis. ICF 1 has an administrative cost for suppliers estimated between 4.5 and 5

[16] This should not represent any additional burden on oil producers compared to current practice.
[17] For some feedstocks, such as material transferred to refineries for the chemicals industry, it may be unduly burdensome to demand full mass balance assessment of constituent feedstocks – or lifecycle assessment of all chemical processes involved in production of those materials. For the purposes of this report, we shall assume that reporting is only required for intermediate materials that remain within the petroleum supply chain, as distinct from the chemicals supply chain.

million euros per year.[18] ICF 1 assumes that reporting is done only by feedstock, in contrast to Option 0 in which reporting would be required by MCON. Option 0 therefore requires more detailed reporting, although the number of data points is essentially unchanged for any given batch of oil – MCON and crude origin vs. feedstock and crude origin. Given the availability of computerized data handling systems able to manipulate much larger quantities of data than the minimal set required for FQD reporting, we see no reason that the systems required for the Option 0 should be any more expensive than the systems required under ICF 1. That said, it seems reasonable to expect that a reporting system with many more possible variations would be more susceptible to erroneous or even fraudulent data recording than a system that has only to identify feedstock. Managing the risk of data entry errors, data transfer errors and so forth would require additional expenditures on verification by supply chain participants.

Allowing for the cost of data maintenance and internal and external verification by refiners and traders to double (due to the increased data complexity) would increase the upper estimate of the annual cost from 8.5 million euros to 9 million euros for the whole EU.

This is still substantially below the estimated cost to suppliers in CE Delft (2012). When corrected for the full number of refineries considered by ICF, the Delft estimate for administrative cost is 56 to 103 million euros. Delft allow in particular for a much larger manpower commitment to data tracking – up to 4 ongoing FTE for each complex refinery in Europe, compared to a maximum time commitment of about one third of an FTE in the ICF study. Delft also allow for much higher initial costs to put appropriate systems in place – up to 15 FTE for one year, compared to ICF's estimate of a 10 day commitment for a complex refinery to set up internal data tracking tools, plus two days to review regulation.

For initial costs, ICF's estimate seems optimistic. There is likely to be substantial management overhead to putting in place systems to respond to a new reporting obligation. For instance, while it might be fair to expect a single person to come to terms with a new regulation within a few days, if compliance approaches have to be discussed and agreed among a rather larger group, time commitments would increase quite rapidly. It is also unclear whether ICF account for time expenditures that will be required to work with suppliers to ensure that chain of custody is implemented upstream. Certainly, the time allowances would permit only very basic engagement. While in general the data required for crude oil imports will be consistent with data that refiners already have at hand, some additional burden can be expected associated with explaining chain of custody requirements to suppliers and ensuring that these are implemented.

Delft's estimate of 10-15 FTE, on the other hand, seems excessive. Data reporting and collection on feedstocks used for petroleum production would be very much simpler than the data collection required for biofuels under the Renewable Energy Directive (where in some cases quite extensive lifecycle analysis data may need to move along the chain). On the other hand, the volumes of material for which data would need to be

[18] Based on adjustments to the original ICF analysis as discussed above.

tracked would be rather large, as biofuel volumes are only a fraction of fossil fuel volumes supplied in Europe. Between a lower level of detail and a higher volume of fuel to monitor, we believe that it is reasonable to treat the likely administrative burden of crude oil data tracking as comparable to the administrative burden of biofuel data tracking. AEA (2009) report that the highest estimate from fuel suppliers of the initial administrative cost incurred to set up systems under the UK's Renewable Transport Fuel Obligation (RTFO) for biofuels was between £10,000 and £100,000 (11,230 – 112,300 euros based on 2009 exchange rates[19]). ICF's high end estimate for initial cost per operator is at the very low end of this range (12,250 euro), but Delft's estimate of 1,200,000 - 1,800,000 euros is well beyond it. As the obligated parties under the RTFO are in general the same fossil fuel suppliers that would be obligated parties under FQD (in the UK), and given that the experience of implementing Renewable Energy Directive reporting should be a useful guide to implementation of crude oil reporting, there seems to be little reason to believe that initial costs for crude oil reporting would exceed the initial costs reported for the RTFO. Delft's estimates of initial administration costs for crude feedstock reporting are therefore considered likely to be excessive by a factor of at least 10.

The ongoing costs reported by Delft are more in line with ongoing administration costs reported by suppliers under the RTFO, but still at the high end of what seems reasonable. With the maximum ongoing administration and verification costs reported to AEA (2009) both falling in the reported range £10,000 to £100,000, the highest ongoing cost consistent with this reported data would be of the order of £200,000 per year, while the typical cost is likely to be more like £20,000. This compares to an annual verification cost range of €75,000 to 300,000 reported by Delft. The ongoing data management and verification costs reported by ICF are in the range €20,000 to 40,000 per year. We therefore conclude that Delft's estimate of administrative costs is likely to be excessive by a factor of at least 3, and possibly as much as 10.

Scaling down Delft's initial administrative cost estimate by a factor of 10, and its ongoing cost estimate by a factor of three, while applying the correction for an increased number of refineries, gives a revised administrative cost range of 14 to 28 million euros across the EU. Taken with the revised estimates from the ICF study, the annual administrative cost of implementing crude oil reporting in line with Option 0 would be expected to be of the order of 10 million euros for the whole EU.

1.5.1.a. The other options

The 3 alternate options differ from reporting in Option 0 (baseline) as follows:

- Option 1 (elevated by fuel): 'opt-out' suppliers would be permitted to report their own actual values for some or all of the MCONs supplied. For any MCONs for which actual values were not reported, they would act like opt-in suppliers. Opt-in

[19] We have not explicitly adjusted these values for inflation, as the values we are working with are only broad estimates and the change due to inflation is insignificant compared to other uncertainties.

suppliers would not have to report at the MCON level, and instead would report (**elevated**) carbon intensities by fuel type only (primarily petrol and diesel). Supplier specific estimates of crude oil carbon intensity would count towards compliance obligations.

- Option 2 (average by fuel): ‘opt-out’ suppliers would be permitted to report their own actual values for some or all of the MCONs supplied. For any MCONs for which actual values were not reported, they would act like opt-in suppliers. Opt-in suppliers would not have to report at the MCON level, and instead would report (**average**) carbon intensities by fuel type only (primarily petrol and diesel). Supplier specific estimates of crude oil carbon intensity would count towards compliance obligations.

- Option 3: ‘opt-out’ suppliers would be permitted to report their own actual values for some or all of the MCONs supplied. For any MCONs for which actual values were not reported, they would act like opt-in suppliers. Opt-in reporting would be identical to the baseline, except that **elevated** values would be assigned as defaults rather than average values. Supplier specific estimates of crude oil carbon intensity would count towards compliance obligations.

The burden of reporting supplier specific values under any of these options should be comparable to the burden of reporting supplier specific values under Option 3 of the ICF assessment. ICF consider three alternatives for the reporting approach for opt-out suppliers – actual measurements, engineering based estimates by the suppliers using custom developed tools, and use of existing lifecycle analysis tools. In task 2, a GHG reporting scheme is outlined based on reporting at least a minimum set of relevant oilfield data, allowing supplier specific emissions values to be calculated using the OPGEE model. The burden of reporting under such a scheme would be most comparable to the third reporting alternative proposed by ICF, the use of existing lifecycle analysis tools. Based on 56 out of 129 oil suppliers opting out, they estimate total costs across the EU of 50,000 to 230,000 Euros. This is based on administrative costs of 10,000 to 25,000 euros per opt-out supplier.

The rate of opt-out would depend on whether the available defaults were based on average values (Option 2) or elevated values (Option 1 and Option 3). A higher rate of opt-out would be expected given elevated defaults than given average ones. The rate of opt-out would also depend on the extent to which suppliers believed that they would be able to demonstrate lower-than-default carbon intensities. In the ICF report, it is assumed that suppliers would either opt-in completely or opt-out completely (i.e. that the decision to opt in or out would be based on that supplier’s overall carbon intensity). Here it is proposed that, analogously to the reporting under the UK Renewable Transport Fuel Obligation, suppliers would be permitted to choose which MCONs to opt-out for. The decision to opt out would therefore not be based on the overall carbon intensity of a supplier’s crude mix, but on the carbon intensity of that supplier’s lowest carbon crudes. Under such a system, it is likely that more suppliers would partially opt-out than under the ICF scenario – however, because they would be able to cherry pick to report actual data for those crudes where such data was most accessible, the reporting burden per opt-out supplier would likely be less.

It is anticipated that the most opt-out reporting would occur under Option 3. In this option, elevated defaults would be provided for all crudes. If in most cases the estimates of MCON emissions used to set the defaults represented a broadly accurate characterization of the real carbon intensity, then reporting additional data in order to be awarded an 'actual' value would be worthwhile for most MCONs. There would likely be some cases where actual reporting of an MCON CI was not beneficial. These would be cases where the average MCON CI had been underestimated, and the real CI was higher even than the elevated default. Such cases would however be the exception, especially for high degrees of carbon intensity elevation in the default values. Under Option 3, therefore, the main limitation on actual value reporting would be data availability.

Under Option 1, the use of elevated defaults would provide an incentive to report actual data, but because these defaults would only be at the fuel type level, for many MCONs (those for which the actual value was higher than the fuel type default) it would never be worthwhile to engage in actual reporting. This would be even more likely in Option 2, where roughly half of MCONs would be expected to have carbon intensities above the average default by fuel type. This case is similar to ICF 3 (ICF hybrid, average defaults).

By reference to the ICF report, a first estimate would be that under Option 2, about 40% (based on 56 out of 129 refineries opting out in ICF 3) of crude would be reported with actual values. Rather than being concentrated among only 56 refineries of suppliers, it is assumed that this reporting would be spread across a larger number of refineries reporting actual values for only some of their MCONs. Assuming that the average carbon intensity for Europe is accurately estimated, around 50% of MCONs would have carbon intensities below the average defaults, but it would not be worthwhile to report actual data where this difference was very marginal. Also, while reporting on these lower carbon MCONs would be rational if data was available, the 40% estimate may not pay adequate regard to data collection barriers for some MCONs. As an example, a large fraction of the oil coming to Europe comes from Russia and the rest of the Former Soviet Union. At present, there is only a very limited amount of data for these fields available in the public domain. Oil refiners will have access to a larger quantity of data through commercial data collection agencies and direct relationships with oil producing companies, however it is not at all guaranteed that the full minimum dataset for OPGEE analysis would be readily available to a given oil supplier. In that case, they would only be able to report actual data for a subset of those MCONs.

There is no direct precedent for the type of crude oil data reporting that would be required for opt-out suppliers under any of these options. This makes it difficult to make any firm prediction regarding the level of actual-data reporting that would be seen under any option, beyond identifying the likely hierarchy (i.e. most in Option 3, then Option 1, then Option 2). However, to give an indication of how administrative costs might differ, below the case is presented that 60% of data would be reported as actual in Option 3, 40% in Option 1 and 20% in Option 2.[20] Building from the ICF estimate of the cost to opt-out reporters using an existing LCA model gives the estimated administrative cost ranges shown in Table 1.13. Those cost assessments include the increased monitoring burden described for the baseline (based on implementation of MCON level reporting instead of feedstock reporting), and the other adjustments to ICF's assessment described above.

Table 1.13. Administrative cost estimates by Option

OPTION	% OF OPT-OUT REPORTING	LOW COST (MILLION EURO)	HIGH COST (MILLION EURO)
Baseline, Option 0 (based on ICF 1)	0	8.5	8.9
Elevated by fuel, Option 1 (based on ICF 3)	40	8.8	11.2
Average by fuel, Option 2 (based on ICF 3)	20	8.6	10.3
Elevated by feedstock/MCON, Option 3 (based on ICF 3)	60	9	12.1

Based on this analysis, it would be anticipated that the administrative burden of reporting under Option 3 would be highest, followed by Option 1 then Option 2. Because the difference in costs is driven by opt-out reporting it should be borne in mind that the higher MRV costs in Option 3 would reflect the voluntary acceptance by suppliers that opting out provides benefits outweighing the costs. As noted for the baseline case, the Delft administrative cost estimates are somewhat higher than the ICF estimates in general.

1.5.2. Administrative cost to public authorities

The cost to public authorities of implementing fossil fuel carbon accounting under the FQD would be highly sensitive to the division of labor between public authorities and economic operators in undertaking verification and assurance of data and chain of custody. ICF and Delft both assume that the bulk of the cost burden for data assurance would be placed on economic operators in the fuel supply chain. For instance, Delft report that, "It can be expected that Member States will transfer the responsibility for the verification to the suppliers, by means of obligatory verification systems."

[20] Based on the expectation that there would be some value to opt-out reporting for almost all crudes in Option 3, for most crudes in Option 1 and for somewhat below half of crudes in Option 2; that the transaction costs of opt-out reporting would discourage it where the benefit is marginal, and that a significant fraction of data would not be easily available to suppliers.

The largest difference in public burden between the options is between Option 0 (baseline) and the other three. This is because Options 1 to 3 would all require members states to put in place systems to handle and verify data on the carbon intensity of specific crudes, whereas Option 0 requires only that they should handle data on which crudes have been used. ICF predict only a 20% difference in costs to public authorities between ICF 1 (ICF defaults by feedstock, like Option 0) and ICF 3 (ICF hybrid, average defaults, most similar to the other three options), but this likely understates the burden on Member State authorities. In Option 0 (baseline), there would be a very limited increase in data reporting compared to current practice. Additional procedures would need to be put in place, but reporting of crude/feedstock trade names is not qualitatively different to reporting currently undertaken by customs authorities, and thus for the baseline the minimal costs described by ICF are likely to be reasonable.

The hybrid reporting options, however, would allow for a qualitatively different type of data to be reported to Member States, and thus require genuinely new systems of data tracking and assurance. One pertinent comparison for public authority costs is the cost of regulating biofuels under the RED/FQD. The biofuel market requires chain of custody to be implemented for carbon intensity data and the provision of guidance to economic operators. This is comparable to the type of data tracking and reporting that would be necessary for carbon intensity reporting by crude under FQD. In 2008/09 and 2009/10, the UK Renewable Fuels Agency (RFA, since dissolved) published annual accounts detailing the cost of running the agency (RFA 2010, 2011). During this period, the RFA developed carbon and sustainability rules (first independently, and then as an implementation on the rules in RED/FQD), guidance on the application of those rules and appropriate chain of custody and verification, and supported a research program on biofuel sustainability issues. It also administrated a computerized system for reporting volume, carbon and sustainability data for the UK fossil and biofuel market. The burden of verification under the RTFO is largely placed on suppliers, with the RFA (and latterly the UK Department for Transport) requiring statements from qualified auditors to verify reported data. In that respect, the RTFO system is a good comparison for the type of verification systems Delft and ICF expect to see for FQD data.

The reported net expenditures of the agency in 2008/09 and 2009/10 were about £1.3 million per annum. Adjusted for inflation and exchange, that is equivalent to about 1.7 million euro per year now. Clearly, this is much higher than the ICF estimate annual cost across Europe for FQD reporting of ~ 50,000 euro per year. There are however several reasons to expect that the costs of managing carbon reporting under FQD would be substantially lower than the costs incurred by the RFA in this period.

- These costs cover a period during which reporting guidance was being developed and amended intensively. Clear guidance from the European Commission through an implementing measure on Article 7a would minimize the need for Member State's individually to invest extensive effort in developing new schemes and guidance.

- These costs included a senior management structure, research undertakings and communications staff. None of these would be necessary for a least-cost implementation of carbon accounting under FQD.
- The competence developed in member states and by economic operators to implement biofuel reporting under RED/FQD will be substantially transferable to the implementation of carbon reporting under FQD. In several member states, it is likely that the responsibility for administering fossil fuel carbon intensity reporting would be taken on by the same bodies as currently manage carbon reporting for biofuels, using the same tools and similar chain of custody approaches.
- There are fewer parties involved in the fossil fuel industry than the biofuel industry. This should reduce the burden of data management and guidance provision.
- The UK is one of the larger economies in Europe, and the UK civil service has proportionately higher capacity to implement a complex administrative apparatus for the RED than would be likely in some other Member States (in part because some other Member States are able to follow the lead of larger countries like the UK in setting up control systems). The UK example should not therefore be considered typical of what would be required in other member states.

While the RFA budget certainly represents an upper limit for the potential Member State cost of implementing fossil fuel accounting under the FQD, it seems likely that the ICF estimate is highly optimistic in terms of the minimum staff commitment that would be required to implement a new regulatory system. It is likely that in each Member State at least one civil servant would be required to commit a substantial fraction of their time to managing FQD reporting and compliance checks. It seems reasonable to assume that on average across the EU each Member State would need to commit at least half an FTE to the task at desk officer level. At 120 workdays per annum, and taking the ICF cost per person day of 157 euro, this would represent an annual cost for desk officer time of 18,840 euro per Member State - 528,000 euros per year for the EU as a whole.

Allowing for associated management and oversight (plus the setup costs for requisite reporting systems) to double that annualized cost, then the annual cost to public administrations across Europe would be at least 1 million euros per year. This is a crude estimate, and real costs will be extremely sensitive to the way that the regulation is implemented. The cost per Member State is likely to vary greatly depending on size of fuel market and how efficiently administration is dealt with. There will also be tradeoffs between robustness and cost of any systems put in place. The cost to public authorities will be driven primarily by the need to put systems in place, develop procedures and undertake outreach with fuel suppliers. Once these systems are in place, the volume of actual data being reported by suppliers is likely to be only a weak driver of increased costs. As the highest volume of data reporting would be expected in Option 3 (elevated by feedstock/MCON), this is likely to be the most expensive option for public authorities, with Option 2 (average by fuel) the least expensive. However, the difference between very limited reporting and very high levels of reporting should not change the order of magnitude of the cost to public authorities, provided efficient systems are in place and the assurance systems introduced by economic operators are largely effective. This is based on the assumption that Member States need to undertake only limited checks on the veracity of reported data, because third party assurance schemes are effective and reliable. Inadequacies in third party assurance could again result in dramatically increased costs to public authorities, but there is no attempt to quantify the implications of such a hypothetical situation.

Overall, the cost to public authorities of Option 0 is expected to be minimal. For any of the other three options, annual costs across the EU are anticipated to reach at least 1 million euros, Costs under Option 3 are expected to be higher than Option 2 or Option 1, by perhaps 50%.[21] Indicative costs to public authorities are shown in Table 1.14.

Table 1.14. Potential cost to public authorities

OPTION:	0	1	2	3
Cost:	€50,000	€1,200,000	€1,000,000	€1,500,000

1.5.3. Emissions reductions and compliance costs

Some of the options considered here would or could change the level of emissions reductions that would be required to achieve compliance with the emissions intensity reduction target of the FQD. Building on the cost assessment in the ICF impact analysis, this subsection presents an assessment of the potential cost implications of those compliance changes in each option.

1.5.3.a. Option 0

The baseline option, Option 0, includes no measure that would create additional emissions reductions options (i.e. it would not add any new compliance options under FQD). It would allow the European Commission to develop its understanding of the EU fossil fuel market and of the carbon intensity of the supply chain, and the data collected may support future regulation. If the data collected under Option 0 were used to update the carbon intensity of the ‘fossil fuel comparator’ under FQD, it could also result in adjustments to the stringency of the targets for existing compliance options. It is generally anticipated that the carbon intensity of fossil fuel used in Europe is more likely to increase than decrease (c.f. for instance ICCT/ER [2010]). In that case, Option 0 would result in an increased requirement for carbon emissions reductions from alternative fuels (in $MtCO_2e$), but also in slightly increased carbon savings being reportable for a given alternative fuel. This is because the carbon savings reportable for alternative fuels are to be calculated against “the latest available actual average emissions from the fossil part of petrol and diesel consumed in the Community as reported under this Directive” (FQD Annex

[21] Author’s expert opinion.

IV paragraph 19). This means that a potentially slightly larger set of biofuels would meet the emissions reduction threshold of the Directives.

About 58 MtCO_2e of emissions reductions must be delivered to comply with the FQD, given the current carbon intensity of the EU fuel mix (ICF report). If the carbon intensity of oil supplied in Europe does not increase to 2020, then Option 0 would have no impact on the need to deliver carbon emissions reductions, and hence impose no extra compliance cost.

However, if the carbon intensity of the 2020 mix was calculated under Option 0 to be 1 gCO_2e/MJ higher than the 2010 baseline[22], it would require about 10 million tonnes of additional carbon savings from alternative fuels and UERs in order to deliver FQD compliance. According to ICF (c.f. Table 4.11 of the ICF report), in the non-iLUC case the marginal cost of additional emissions reductions beyond the 58 MtCO_2e already required is from 3 to 18 €/tCO_2e. The ICF report predicts a more moderate increase in the carbon intensity of the EU crude mix – an increase of 0.19 gCO_2e/MJ in carbon intensity if crude mix changes are accounted for (ICF report, §8.3). In this case, an additional 2 MtCO_2e of savings would be required, with incremental cost of 3 to 8 €/tCO_2e.

For a 1 gCO_2e/MJ increase in the carbon intensity of the EU fossil fuel mix, the additional compliance cost from implementing Option 0 could be of the order of 140 million euros, based on ICF's estimates. The additional compliance costs associated with an increase of 0.19 gCO_2e/MJ would be more modest, around 11million euros. These additional costs would result from offsetting the increasing carbon intensity, i.e. they would be associated with delivering additional emissions reductions through alternative fuels and upstream reductions to preserve the environmental integrity of the program. In the iLUC sensitivity scenario, additional emissions reductions from alternative fuels have a higher incremental cost. In that case, ICF only explicitly identify 7 MtCO_2e of additional potential savings (ICF Table 4.13), with costs from 130 – 200 euros per tonne. In order to offset an increase of 1 gCO_2e/MJ in the carbon intensity of fossil fuel production, all these savings and an additional 3 MtCO_2e would be needed. Assuming that the remaining 3 MtCO_2e of savings needed could be achieved at a cost of 250 euros per tonne, Option 0 would drive an additional cost of 1.7 billion euro (compared to the case where an increase in the carbon intensity of the EU crude mix is ignored) in the case that iLUC reporting is implemented. Again, this cost relates to delivering additional alternative fuels and upstream emissions reductions to offset the increasing CI of crude oil. For a 0.19 gCO_2e/MJ increase, the cost of offsetting would be around 240 million euro.

Given that 1.7 billion euros is a significant potential cost, it is important to understand the context of these costs in the ICF report. ICF predict that introducing iLUC accounting would reduce the use of biofuel, biodiesel in particular, as a compliance option. Because biofuel is more expensive than fossil fuel, ICF therefore expect iLUC accounting to actually reduce the cost of meeting the 6% carbon intensity reduction target, by moving compliance to cheaper options. They therefore anticipate 6 billion euros of net savings

[22] ICCT/ER (2010) project an expected increase by 2020 in the carbon intensity of the EU crude mix of 1 gCO_2e/MJ

in the iLUC scenario compared to the scenario without iLUC accounting, due to reduced biofuel costs. Based on ICF's analysis, a policy with iLUC accounting and Option 0 crude accounting would therefore still be 4 billion euros ***cheaper*** than a policy with neither iLUC accounting nor updates to crude oil carbon intensity, even if the crude mix increases in CI by 1 gCO_2e/MJ by 2020. The cost implications of these cases of Option 0 implementation are shown in Table 1.15.

Table 1.15. Cost implications for FQD implementation of Option 0 (baseline) if the carbon intensity of the crude mix increases. Main number is million €, number in parentheses is cost in euros per tonne of additional carbon dioxide abatement.

		APPROXIMATED IMPLEMENTATION COST IMPLICATIONS FOR GIVEN CHANGE IN EUROPEAN CRUDE CI * (2010-2020)		
		+ 0 gCO_2e/MJ	+ 0.19 gCO_2e/MJ	+ 1 gCO_2e/MJ
Expenditure in M€ and (in parentheses) abatement cost in €/tCO_2e, compared to case with no update to EU crude CI	No iLUC	0 (0)	11 (6)	136 (14)
	iLUC	0 (0)	240 (129)	1711 (175)

** Based on the marginal abatement costs from the ICF report*

In conclusion, Option 0 would only deliver emissions reductions, and cause associated cost increases, if the carbon intensity of EU crude oil exogenously rises (for instance due to changing trade patterns or increased availability of heavy Canadian crudes to Europe). Without iLUC accounting, Option 0 would be expected to offset any emissions increases in crude oil at modest cost. With iLUC accounting, the cost of marginal additional carbon savings would be expected to be higher as some biofuels would be ruled out as compliance options. Based on ICF's analysis, costs for these additional emissions reductions would be over 100 €/tCO_2e.

1.5.3.b. Options 1, 2 and 3

Above, Option 0 (baseline) was compared to a case in which there was no attempt to revise estimates of the average carbon intensity of EU fuel (this corresponds to the baseline, ICF 0, in the ICF report). However, because Option 0 is identified as the baseline for this report, henceforth the other options will all be compared directly to Option 0. This means that the cost values in section 1.5.3.a should not be directly compared against the cost numbers presented in section 1.5.3.b.

As noted above, Option 1 (elevated by fuel) differs from Option 0 (baseline) in the following ways:

- Default emissions values would be assigned by fuel type, rather than by MCON/feedstock;
- Default emissions values would be conservative ('elevated');

- Suppliers would have the opportunity to 'opt-out' and report actual CIs for their MCONs where data is available;
- Suppliers reported specific crude oil carbon intensities would count towards their compliance obligations.

Option 2 (average by fuel) differs from Option 0 (baseline) in that:

- Default emissions values would be assigned by fuel type, rather than by MCON/feedstock;
- Suppliers would have the opportunity to 'opt-out' and report actual CIs for their MCONs where data is available;
- Suppliers reported specific crude oil carbon intensities would count towards their compliance obligations.

Option 3 (elevated by feedstock/MCON) differs from Option 0 (baseline) in that:

- Default emissions values would be conservative;
- Suppliers would have the opportunity to 'opt-out' and report actual CIs for their MCONs where data is available;
- Suppliers reported specific crude oil carbon intensities would count towards their compliance obligations.

Under any of the hybrid reporting schemes, the reported average carbon intensity of the EU crude mix could diverge from the best estimate of the average carbon intensity of the EU crude mix. This is because of a combination of elevated defaults (Options 1 and 3) and selective reporting. The following analysis considers the potential cost and emissions implications of introducing the possibility of selective reporting. It does not include at this stage the new compliance options introduced by hybrid reporting (e.g. crude switching).

Malins et al. (2014) estimated the upstream carbon intensity of the EU crude oil supply as 10.2 gCO_2e/MJ. Using the crude carbon intensities from that study, combined with ICF's incremental MAC curves, it is possible to estimate how the reported carbon intensity of EU crude would differ from this best-estimate carbon intensity under each Option, and what the cost implications of this would be. In general, if the reported 2020 carbon intensity is less than the best-estimate, that generates costs savings as less emissions reductions need to be delivered to achieve compliance.

For Options 1 and 2, it is assumed that the actual carbon intensity is reported for the lowest carbon intensity 40% and 20% of crudes respectively (c.f. Table 1.13). This selective reporting reduces the reportable carbon intensities. For Option 1, the highest CI 60% of crude is reportable with an elevated fuel default. Here, a 20% elevation is considered on the upstream CI of the fuel.[23] This tends to run counter to the effect of the selective reporting.

[23] Levels of elevation are discussed further in section 4.3.

Under Option 3, because defaults would be set by MCON, the pattern is different. Since each MCON has an elevated default, actual reporting will occur for both low-CI and high-CI fuels. As an illustrative example, therefore, a case is modeled where a randomly determined 60% of crudes from Malins et al. (2014) are reported at actual values, while the rest are reported at elevated values (elevated by 20% again).

Table 1.16 shows the emissions and cost implications of these implementations options, as compared to Option 0. Again, three cases are shown for the trend change in the actual CI of EU crude: no change; an increase of 0.19 gCO_2e/MJ in line with the ICF report; and an increase of 1 gCO_2e/MJ in line with Malins et al. (2014). The table shows the reportable change in the average carbon intensity of the EU crude mix for each case, the change in the total carbon emissions reductions needed to comply with the FQD, and then the total cost (in million €) and carbon abatement cost (in €/tCO_2e) associated with each case. Negative costs represent savings. Negative abatement costs represent the cost avoided for every tonne of carbon reductions that are not achieved (compared to Option 0).

Table 1.16. Changes in emissions reductions and costs due to potential selective reporting under the three hybrid options (excluding impact of changes in crude choice)

REGULATORY OPTIONS			ASSUMED ACTUAL CHANGE IN CRUDE CI (2010-2020), gCO_2e/MJ		
			0	+ 0.19	+ 1
Option 1 (elevated by fuel)	Reported CI change (2010-2020), gCO_2e/MJ		- 0.46	- 0.27	+ 0.54
	Change in total required emissions reductions for FQD compliance, $MtCO_2e$		- 4.5		
	Expenditure in M€ and (in parentheses) abatement cost in €/tCO_2e, compared to Option 0	No iLUC	-5 (-1)	-14 (-3)	-80 (-18)
		iLUC	-450 (-100)	-525 (-116)	-964 (-214)
Option 2 (average by fuel)	Reported CI change (2010-2020), gCO_2e/MJ		- 0.75	- 0.56	+ 0.25
	Change in total required emissions reductions for FQD compliance, $MtCO_2e$		- 7.4		
	Expenditure in M€ and (in parentheses) abatement cost in €/tCO_2e, compared to Option 0	No iLUC	-6 (-1)	-17 (-2)	-121 (-16)
		iLUC	-668 (-91)	-776 (-105)	-1399 (-190)
Option 3 (elevated by feedstock /MCON)	Reported CI change (2010-2020), gCO_2e/MJ		+ 0.66	+ 0.85	+ 1.66
	Change in total required emissions reductions for FQD compliance, $MtCO_2e$		+ 6.4		
	Expenditure in M€ and (in parentheses) abatement cost in €/tCO_2e, compared to Option 0	No iLUC	76 (12)	99 (15)	147 (23)
		iLUC	929 (145)	1092 (170)	1604 (250)

Both Options 1 and 2 result in reduced stringency of the emissions reduction target. In Option 2, the average carbon intensity is driven down by selective reporting, reducing the carbon emissions reductions needed for FQD compliance by 7.4 $MtCO_2e$. In Option 1, while the elevated defaults tend to increase the average carbon intensity, this effect is exceeded by the reduced emissions due to actual reporting, and the stringency is reduced by 4.5 $MtCO_2e$. In both cases, there are cost reductions regardless of whether iLUC reporting has been introduced – however, because iLUC accounting moves the marginal compliance options to the right along the MAC curve, the savings are much greater if iLUC accounting has been implemented.

In contrast, despite being a stronger incentive to report actual values, Option 3 does not drive selective reporting in the same way – it creates an incentive to report actual values for both high and low carbon crudes, and the (unelevated) default values by MCON are expected to be close to the real carbon intensities. Compared to Option 0, Option 3 increases the stringency – because there is no reduction compared to Option 0 for reporting actual MCON values, while defaults are elevated by 20%. In all cases considered, these additional required carbon reductions result in cost increases for the policy.

Note that this analysis assumes that the default values for fuels are set to be representative of the average fuels used in Europe. In the ICF report, it is assumed under ICF 3 (ICCF hybrid, average defaults) that as the system progressed, the fuel (or feedstock) level defaults would be iterated to be representative of the fraction of fuel for which suppliers opted in for default value reporting. Under this assumption, the more suppliers opt-out report their lower carbon fuels, the higher the default CI would get. In the example above, if such a system were implemented in Option 1 it would raise the assumed average upstream CI from 10.2 to 12.9 gCO_2e/MJ in the following year. Under Option 2, the CI would rise to 11.4 gCO_2e/MJ. For Option 1 in particular, because of the use of elevated defaults this process would create an increased incentive for further actual reporting in the following year (when the default crude CI with a 20% elevation would be 15.5 gCO_2e/MJ). This process would offset the benefits of selective reporting, as a diminishing pool of oil was reported using default intensities each year, and as those default intensities rise. This would tend to protect the environmental integrity of the regulation (i.e. maintain the stringency of the FQD targets), but would therefore also be associated with higher costs.

Table 1.16 illustrates the possible implications of selective reporting under a hybrid scheme, but there are other new compliance options that such a system would make available. The ICF impact analysis considers options for both crude and product 'switching'. However, it notes that,

> *"Any option related to products excludes selecting one type of fuel over another (e.g., LPG over diesel or petrol). Such selection could not be induced by a carbon price premium resulting from the FQD requiring compliance in 2020 as drivers for switching between fuels materialize over a longer time horizon stemming from long-term drivers such as changes to vehicle fleets and/or taxation regimes."*

Product switching is therefore not considered any further here, and it is assumed where pertinent that the impact of crude CI changes will be the same on petrol and diesel fuels.

While product switching is not considered, crude switching is certainly a possibility. In the simplest case, crude switching under one of these hybrid reporting systems would involve moving from a relatively high carbon crude to a relatively low carbon crude with similar chemical properties. For instance, Forties from the North Sea and Bonny Light from Nigeria are both light, sweet crudes, but Forties has a lower carbon intensity due to high Nigerian rates of flaring. If a refiner was able to increase its intake of Forties and reduce the intake of Bonny, then it would have an opportunity to report reduced carbon intensity. In Options 1 or 2, this would require actual reporting of the CI for Forties. In Option 3, because the defaults would be MCON linked, no actual reporting of CI data would be required.

In general, refiners will already be using the most cost optimized crude mix available to them, and so it can be anticipated that crude switching will incur costs (for instance due to changing transport distances). However, it can also be assumed that these emissions reduction opportunities will only be taken if they are more cost effective than other available options (e.g. biofuels and UERs), so in all cases it is to be expected that adding the option to switch crudes will reduce overall compliance costs from the policy. As an example, the analysis of the increased compliance costs from Option 3 (elevated by feedstock/MCON) has been redone using the ICF MAC curves including crude switching options, and is presented in Table 1.17. Note that because ICF have modeled a different set of crude switching possibilities under ICF 3 than would in fact be available under Option 3, these results should be thought of as an illustration of the directional effects of crude switching on costs.

Table 1.17. Effects of introducing crude switching options on costs of Option 3 (elevated by feedstocks/MCONs)

REGULATORY OPTIONS				ASSUMED ACTUAL CHANGE IN CRUDE CI (2010-2020), gCO_2e/MJ		
				0	+ 0.19	+ 1
Option 3	Reported CI change (2010-2020), gCO_2e/MJ			+ 0.66	+ 0.85	+ 1.66
	Change in total required emissions reductions for FQD compliance, $MtCO_2e$			+ 6.4		
	Expenditure in M€ and (in parentheses) abatement cost in €/tCO_2e, compared to Option 0	No crude switching	No iLUC	76 (12)	99 (15)	147 (23)
			iLUC	929 (145)	1092 (170)	1604 (250)
		Crude switching	No iLUC	64 (10)	90 (14)	140 (22)
			iLUC	863 (134)	935 (146)	1604 (250)

The cost differences in a scenario in which crude switching is permitted are of the order of a ten per cent reduction in additional compliance cost. The cost of carbon abatement from crude switching is up to €34 million in the iLUC case. This is similar to the finding in ICF's report (€37 million in ICF 3 in the iLUC case). This cost includes increased crude transport costs. This

€34 million cost is associated with 0.3 $MtCO_2e$ of emissions reductions – less than 1% of the savings required from the FQD as a whole.

1.5.4. Carbon leakage

'Carbon leakage' refers to the risk that emissions savings can be achieved in one jurisdiction at the cost of an increase in emissions elsewhere. An example from cap and trade regulations would be the risk that regulating a high-carbon industrial facility in Europe could affect its profit margin to the extent that it would shut down, only to be replaced by a similar facility in a region not subject to emissions regulation. Counting only emissions in Europe, it would seem as if emissions had been reduced – but counting emissions globally, it would become clear that no net reduction had been achieved. Indeed, in the worst case the replacement capacity could have worse environmental performance than the original facility.

Under the FQD, there are several potential mechanisms for carbon leakage. In biofuels, carbon leakage could occur if an increase in EU biofuel consumption occurs at the expense of a reduction in biofuel consumption elsewhere. This type of leakage is predicted in the case of sugarcane ethanol by Laborde (2011), with increased European consumption being linked to reduced consumption in Brazil.

On the fossil fuel side, as the ICF report notes, there is a risk of carbon leakage associated with crude switching, in the event that higher carbon crudes removed from the EU crude pool are still consumed elsewhere. In the analysis of the possibility of crude switching under Option 3 (elevated by feedstock/MCON) presented above, the largest potential contribution of crude switching to emissions savings under the FQD was found to be 0.3 $MtCO_2e$. This is less than 1% of the total saving required under FQD. In the worst case, changes in the crude slate used for European fuels would have no effect on the crudes being extracted, i.e. no net effect on the global crude slate. To give a simple example, one could imagine a case in which U.S. refineries exporting diesel to the EU put in place systems so that any use of tar sands bitumen was associated only with refined product sold in the U.S., while EU exports were associated with lower carbon crudes. Under Options 1, 2, or 3 it might seem that the carbon intensity of the EU crude slate had reduced, but in principle the overall crude slate processed by the Gulf Coast refinery complex might not have changed. The British Columbian Renewable and Low Carbon Fuel Requirements Regulation experienced was subject to similar concerns when it was proposed to allow full disaggregation of crude CI. These concerns were instrumental in having full disaggregation removed from the regulation (Malins et al., 2014).

Wood Mackenzie (2012) assumes not only that any shifts in crude use would be leaky in the above sense, but also that they would be associated with increases in shipping emissions. It finds a potential for crude shuffling to reduce reportable emissions by up to 13 $MtCO_2e$/yr, with an associated increase in global shipping emissions of 1.4 $MtCO_2e$/yr. This is based on a simplified model of the FQD, similar to Option 3 here but limited to ten illustrative crude grades. Wood Mackenzie provides very limited detail of the assumptions that lie behind these anticipated changes in shipping emissions. The implication is that crude switching will always be associated with shipping oil for larger distances, but this is not necessarily the case. Crude sourcing is certainly not currently optimized to reduce shipping emissions, and is not always optimised to minimize shipping costs. There will certainly be cases in which lower carbon intensity crudes will be closer to Europe than high carbon sources, and thus in which crude switching may cause incidental reductions in shipping emissions.

It is certainly correct to note that crude switching could result in some leakage, but it would be premature and incorrect to assume that leakage was the only possible or likely outcome. The introduction of carbon valuation for oil will drive a price spread between higher and lower carbon intensity crudes. This price difference would be strongest under Option 3, as Options 1 and 2 would not produce any value difference for crudes at the high end of the carbon intensity spectrum. While this differential will be much more pronounced in the European market, reduced EU demand will also impact the price spread generally. CE Delft and Carbon Matters (2013) argue that a price differential introduced by crude differentiation in the FQD could drive net emission reductions of up to 19 $MtCO_2e$/yr through a reduced investment in tar sands capacity. It would also not be fair to assume that Europe would remain the only region with crude-carbon differentiation in the long term – California's LCFS already includes a system of crude accounting similar to Option 0, and both additional state LCFSs and a full U.S. LCFS are possibilities in the coming decade. Increasing the size of the region affected by crude-carbon differentiation would reduce the scope for leakage, and increase the strength of the market signal sent to incentivize low-CI crude production.

1.5.5. Environmental benefits

Assessment and quantification of the environmental benefits of hybrid reporting under the FQD is complicated by three major factors. Firstly, the difficulty in predicting whether and to what extent the regulatory signal from hybrid reporting will drive oil producers to change their upstream practices. Secondly, because the baseline that we are comparing against assumes that the 6% emissions reduction target can and will be successfully met using alternative fuels and upstream emissions reduction credits. Thirdly, because the mechanisms through which Member States will implement the 2020 carbon intensity reduction target are not yet clear.

On the first point, there is a lack of research seeking to anticipate how the oil industry would react to carbon pricing in the EU. CE Delft and Carbon Matters (2013) assume that carbon pricing would drive a significant price differential on the global oil market between the highest and lowest carbon intensity oils. While it is reasonable to assume that some price differential would result in the EU market, it is difficult to assess what that differential would be. It is harder to assess how that local differential would be transmitted to the global oil price. Neither Wood Mackenzie nor CE Delft and Carbon Matters are convincing in the evaluations given. A more robust assessment may be possible based on modeling of the global oil market given some input assumptions about the carbon cost under the FQD, but such a modeling exercise is beyond the scope of this report. Even then, a sound estimate of the price differential experienced by upstream producers is only a starting point. Anticipating the impact on oil production practices would require a model of investment decisions and an understanding of the options available to reduce carbon intensity at individual oil fields and the cost of implementing those options. This is an area that remains poorly documented in the public literature, and given the lack of available data no attempt has been made in this paper to quantify the likely emissions savings from such measures. However, this should not be interpreted to indicate that no such savings are anticipated.

Wood Mackenzie find that an expected price differential would influence crude purchase decisions, but would have no impact on upstream practices or investment decisions. This absolutism is not considered credible. The underlying premise of CE Delft and Carbon Matters that changes in crude prices would affect investment decisions in high carbon crudes seems sound, but quantifying the net carbon emissions reductions over time delivered by such investment drivers is a complex task, that would require considerable further research.

The second complication is in the baseline. In the baseline it is assumed that all regulated parties in all Member States will comply with the carbon intensity reduction target. In that case, compliance through changing the crude supply would replace compliance through alternative fuels, and therefore does not represent an environmental benefit. If a ‘real’ carbon saving in the crude supply chain replaces a ‘real’ carbon saving from alternative fuels, the only change is in overall compliance cost. Some savings available through hybrid reporting, such as savings through selective reporting, would not represent real net savings, and therefore would tend to reduce the environmental benefits of the program, albeit simultaneously reducing its cost. The same would generally apply to savings through crude switching. Even this picture is not simple though. iLUC analysis for the Commission (Laborde, 2011) shows that some alternative fuels, notably biodiesels, may not deliver net savings either. A paper saving in the crude market that displaces a biofuel with higher net emissions than diesel could actually result in a reduction in net carbon emissions, but this is surely not the underlying intention of the policy. As was observed in the Gallagher Review (2008) in the context of indirect land use change, applying carbon accounting could produce perverse incentives if the net carbon implications of increasing or decreasing the supply of a given fuel are not fully captured.

Finally, the third major issue in making a quantitative assessment of the environmental benefits of implementing hybrid reporting is that it is not clear what mechanisms will be applied by Member States to ensure compliance with the carbon intensity reduction target. The use of the ICF cost curves in this analysis assumes that there will be a working market in carbon emissions reductions from transport fuels, something like California’s LCFS, but no such market is yet in effect in the EU. The conclusions from this model would therefore be invalidated in the case that some Member State intended compliance with the FQD to be delivered through biofuel production quotas, for instance.

One issue here that requires further consideration is whether the carbon reductions that would be reportable in the fossil fuel supply chain under a hybrid reporting scheme are truly comparable to the carbon reductions that would be reportable from alternative fuels. In both cases, the reportable reductions are approximations that do not reflect all the indirect effects of fuel changes. For alternative fuels, that means leakage, indirect land use change, other indirect agricultural emissions changes and the fossil rebound. For fossil fuels, it means leakage and selective reporting. Applying the carbon intensity reduction target of the FQD to both fossil and alternative fuels would be implicitly based on the desire to apply a technology neutral incentive for all emissions reductions. However, if the real net impact of savings delivered by different technologies are systematically under- or over-estimated, then that technology neutrality is undermined. Paradoxically, in some cases one could argue that the only way to genuinely give comparable value signals to the different markets would be through setting independent targets. These issues are worthy of further consideration as the European Union considers policy options to reduce transport emissions to 2030.

1.5.6. Data reporting, chain of custody and commercial confidentiality

Any of the options discussed in this report would require the implementation of new data reporting requirements, and require new chains of data custody to be implemented to meet these requirements. Option 0 (the baseline) and Option 3 (elevated defaults by MCON) would require that all fuel suppliers reported the MCON origin of supplied fuels. For the case of an oil refiner, as an obligated supplier, this requirement would be relatively simple. Refiners will already know the MCONs for the crudes being refined. For these cases, if reported data is kept confidential by national/EU level administrators there are no commercial confidentiality issues. If reported data was to be published, however, refinery operators could be concerned that commercially sensitive data would be made available to competitors. Reporting only aggregated data could potentially alleviate such concerns. Aggregation could be done over time, over MCONs sourced from a given region, over all refineries operated by a single supplier or by some other appropriate characteristic. Any measures to disguise the specific MCONs processed by each facility would be likely to make data publication more acceptable to industry.

Where the refiner is also the obligated party, they could be expected to report directly to the national or EU level administrator, and therefore data would not need to be handled by competitors. However, if a refiner were selling refined or intermediate product on to a second company with a data reporting obligation, there would be a need to pass MCON data along the chain of custody, potentially giving this second company access to commercially sensitive information. This could apply to refiners both within Europe and to exporters in other countries. Requiring foreign fuel producers to disclose commercially sensitive information to European fuel importers could be politically sensitive. One approach to managing such commercial and political sensitivity would be to implement a chain of custody approach in which detailed data was never accessible to intermediate parties in the chain. For instance, foreign refineries could be asked to pass only a batch number and related average upstream carbon intensity value down the chain of custody, while reporting the detailed MCON composition of each numbered fuel batch directly to national/EU administrators (either immediately, or by request in an end-of-year reconciliation process). The obligated parties would have the data required to plan compliance with the FQD (the carbon intensity of each batch of fuel) but would not be given privileged information about the oil processed by a given facility. At each stage of the supply chain, it would be determined (e.g. based on mass balance rules) what fuel volume from each batch was passed to the custody of another party. Eventually, a fuel supplier with a reporting obligation would report a range of batch numbers and fuel volumes, and a weighted average carbon intensity, without ever having direct access to MCON data. The average carbon intensity could potentially be used to infer some information about the oils being processed by a supplier facility. But given the many combinations of MCONs that could give any given average CI, it would be impossible to draw firm conclusions this way. Indeed, conclusions drawn in this manner would likely be rather less reliable than assessments already available from market intelligence analysts. Alternately, a system of encrypted data transfer could be implemented by which only data auditors and national/EU administrators would be able to access full data at each stage of the supply chain. It is likely that without implementing some system to protect commercially sensitive data any proposed reporting system under the FQD would face significant opposition.

Options 1 and 2 would not necessarily require passing MCON data down the chain of custody to obligated parties, as defaults would be assigned only by fuel type. However, reporting actual carbon intensity values could again require passing potentially sensitive data to competitors – this would be true in any of options 1, 2 and 3. As this data transfer would only ever occur voluntarily, one option would be to simply require that companies only report actual values when comfortable with the implications of data sharing. However, an alternative would be to implement a system along the lines suggested above, in which detailed data would be passed directly to national/EU administrators, and parties in the middle of the supply chain would be expected to handle only batch numbers. There is further discussion of issues relating to chain of custody and actual value reporting in section 5.9.

1.5.7. Conclusions on options

Table 1.18 provides an overview of the cost and environmental implications of the four options. The administrative cost to operators of implementing Option 0 (baseline) is expected to be of the order of €9 million per year, covering the implementation of additional chain of custody to track MCONs through the supply chain. The administrative costs of Options 1 (elevated by fuel), 2 (average by fuel and 3 (elevated by feedstock) are anticipated to be higher but similar. Depending on the level of opt-out reporting, the total cost to economic operators could be raised by up to €3 million, with Option 3 representing the highest administrative burden. This increased burden is based on an assumption of higher opt-out reporting rates under

Option 3. Costs to public authorities are expected to be lower. For Option 0, these costs should be minimal, as very little additional information handling would be required. For Options 1, 2 and 3, the costs are expected to be of the order of €1 million per year. However, this would be very sensitive to the detail of regulatory implementation, and to the extent to which public authorities are able to achieve synergies between existing systems for biofuel carbon intensity regulation and new systems for fossil fuel carbon intensity regulation.

Table 1.18. Overview of Options

	OPTION 0 (BASELINE)	OPTION 1 (ELEVATED BY FUEL)	OPTION 2 (AVERAGE BY FUEL)	OPTION 3 (ELEVATED BY FEEDSTOCK /MCON)
% of opt-out reporting	0	40	20	60
Administrative cost, in M€ and in parentheses in € per barrel of oil[24]				
Low cost (million euro)	8.6 (0.002)	10 (0.002)	9.6 (0.002)	10.5 (0.002)
High cost (million euro)	8.9 (0.002)	12.4 (0.003)	11.3 (0.002)	13.6 (0.003)
Compliance cost (M€) and in parentheses estimated cost in euro per barrel of oil				
Low cost (no iLUC)	0 (0.00)	-80 (-0.02)	-121 (-0.02)	76 (0.02)
High cost (no iLUC)	138 (0.03)	-5 (0.00)	-6 (0.00)	147 (0.03)
Low cost (iLUC)	0 (0.00)	-964 (-0.2)	-1399 (-0.28)	929 (0.19)
High cost (iLUC)	1711 (0.35)	-450 (-0.09)	-668 (-0.14)	1604 (0.33)
Environmental performance				
Emissions savings delivered by FQD program ($MtCO_2e$)	58 – 68	54-65	50 – 60	64 – 74
Change in emissions savings from case with single default value for crude ($MtCO_2e$)	0 – 10	-4.5 – 5.5	-7.4 – 2.6	6.4 – 16.4
Level of actual reporting	None	Moderate	Lower	Higher

While administrative costs are similar between options, compliance costs could vary significantly. Under Option 0, the only compliance cost would be the cost of offsetting any increases in the carbon intensity of the underlying EU crude mix to 2020. In Options 1, 2 and 3, changes in the carbon intensity of the underlying crude slate are similarly expected to be major drivers of compliance costs, but the costs are also sensitive to the level of 'selective reporting' allowed under the hybrid reporting system. Under Options 1 and 2, default emissions values for fuel types would leave

[24] Based on 2013 EU oil demand of 13.5 million barrels per day.

substantial opportunity for emissions reductions to be claimed through selective reporting, i.e. by reporting actual data for low carbon intensity crudes only. Under both Options 1 and 2 it is therefore expected that there would be compliance costs savings compared to Option 1 – but that these would come at the expense of reduced net carbon reductions. Under Option 3 there would be less scope for selective reporting, and the application of an elevation factor to default CI values would tend to increase compliance costs, as there would be a need to offset reported crude CI increases. In all cases, the cost per barrel of oil to the industry and/or European consumers is anticipated to be very modest, below four eurocents per barrel of oil in all cases in the absence of iLUC factors.

The biggest variable in anticipating compliance costs is whether iLUC accounting is implemented. Because adding iLUC accounting to the FQD would shift the marginal compliance options to the right along the emissions reduction cost curve, a marginal increase in stringency of the regulation would be much more costly to operators if iLUC accounting is implemented than if it isn't. This marginal cost works both ways. In Options 1 or 2, where it is anticipated that selective reporting options under a hybrid system would reduce the overall stringency of the target, there would be a saving on compliance cost, while under Option 3 (in which it is anticipated that the use of elevated defaults would increase the overall stringency of the regulation) there would be a cost increase. It is noted that at the time of writing the European Council has agreed a position against the accounting of iLUC in the FQD – in which case the cost implication would be much reduced under any option.

Given the challenges in estimating costs and benefits from the implementation of these hybrid reporting options, it is difficult to make any unqualified assertion about the comparative benefits of each one.

As to the most accurate reductions, Option 0 is likely to most accurately assess the 6% emissions reduction. Compared to Options 1 and 2, it is more accurate because it would be based on crude level rather than fuel level defaults, and because it would not be subject to selective reporting. Compared to Option 3, it would be more accurate because it would not involve elevated defaults (which effectively increase the stringency of the regulation above the 6% target). In terms of enabling the most accurate assessment of the carbon intensity of the EU crude mix Option 3 would be preferable. It is likely to drive the highest rate of actual value reporting, and hence maximize the capacity of Member States and the Commission to collect additional data. Option 3 also would prevent much of the selective reporting that would lead to inaccuracies in an overall carbon assessment based on Option 1 or 2. Setting defaults by fuel type as opposed to by crude name is unappealing, first because of the wide scope it creates for selective reporting, but also because it would tend not to create any value difference among the various crudes with high carbon intensities. It is in regulation of the highest carbon intensity crudes that the largest opportunity lies to influence investment and deliver efficiencies.

The final assessment of the comparative attractiveness of each reporting option must be based on a subjective assessment of the desirability of pricing carbon in the upstream oil supply chain. Option 3 is likely to be the most effective at imposing a carbon price relatively evenly across all oils, because it does not include fuel level defaults. Option 0 is the simplest to implement. Option 2 would make the target cheaper to meet.

2. Task 2: methodology for estimating average crude default emissions intensities

Present a methodology for estimating upstream, average default values per crude/feedstock trade name to be included in the legislation as well as a supporting discussion of the pertinent assumptions including but not limited to assumed boundary conditions, data gap filling etc.

2.1. Summary

The second task of this report is to present a methodology for estimating average default values for upstream carbon intensity per crude/feedstock trade name (MCON). The proposed methodology is based on use of the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), which at the time of writing is the world's only open source lifecycle analysis model for crude oil production (Malins et al., 2014).

A 'representative fields' methodology is proposed for the purpose of calculating default carbon intensities by MCON. Under this methodology, the carbon intensity of any oilfields feeding each MCON for which data is available would be calculated, and the MCON carbon intensity would be set as the weighted average of the carbon intensity of those fields. Some extraction technologies are not yet included in the OPGEE model – for these, default emissions or (for conventional oil extraction technologies) correction factors have been suggested based on the literature. These defaults/correction factors are shown in Table 2.1.

Table 2.1. Upstream carbon intensity for unconventional feedstocks and technologies

UNCONVENTIONAL PATHWAY	UPSTREAM EMISSIONS INTENSITY (gCO_2/MJ) OR INTENSITY MODIFIER
GtL	19
CtL	129
Kerogen	52
Tight oil (correction)	+ 1.5
CO_2 EOR (correction)	+ 3

2.2. Introduction

This chapter introduces the proposed estimation methodology for assessing the average default carbon intensity of EU fossil fuels under the FQD, for use in Option 0 or 2. It contains a description of the overall methodology, an overview of the OPGEE model itself, a review of literature on fossil fuel pathways not included in OPGEE, a discussion of minimum data requirements for running a field through OPGEE and a brief review of the regulatory language related to fossil fuel carbon intensity reporting under the California LCFS.

2.3. Default value estimation methodology

The Oil Production Greenhouse Gas Emissions Estimator is the only engineering based, open source lifecycle analysis model for crude oil production in the world. Malins et al. (2014) presents OPGEE-based estimations of the carbon intensity of all the crude oils reported as being imported to Europe. OPGEE is already used for regulatory purposes in California, where OPGEE based estimates of upstream crude oil emissions are used in the Low Carbon Fuel Standard.

Both the OPGEE tool and the methodology proposed have been subject to peer review. Much of this peer review has occurred in the context of the use of OPGEE by the California Air Resources Board (CARB) as a regulatory tool in the California Low Carbon Fuel Standard (CA LCFS). As part of this process, the OPGEE tool has been presented at several public workshops over the past few years and thereby subjected formally to public comment and scrutiny. All comments submitted in the relevant comment periods following LCFS workshops are available online through the CARB website and have been answered or incorporated in newer versions of the OPGEE tool. The tool and representative fields methodology have also been exposed to peer review in Europe in the context of the previous DG Clima project on “Upstream Emissions of Fossil Fuel Feedstocks for Transport Fuels Consumed in the European Union” (Malins et al., 2014). The OPGEE tool and results were presented at a European Commission stakeholder workshop in early 2014. The report of that study was also subjected to review by three expert reviewers, Werner Weindorf from Ludwig-Bölkow-Systemtechnik (LBST) GmbH, (S&T)2 Consultants Inc from Canada and Stefan Unnasch from Life Cycle Associates, LLC based in California. Both the peer reviewed comments and the authors responses to these, are available from DG Clima.

Given the extensive review of both the modeling framework and the methodology used to estimate carbon intensities of crude oils, we propose that OPGEE should form the core of the methodology for assigning specific carbon intensities to crude oil used in Europe, on a trade name by trade name basis. This should be based on the representative fields methodology presented in Malins et al. (2014), but aggregating crudes at the level of traded crude names (MCONs) rather than the import reporting categories used in the earlier study. For feedstocks not modeled by OPGEE, it is proposed that default values should be based on studies in the existing literature.

2.3.1. The representative fields methodology

There are thousands of oil fields in the world, producing crude oils (as well as condensate and natural gas liquids in some cases) with a wide range of physical characteristics. In some cases, the oil from a single field is treated as a product on its own and sold to refineries, but in general the oil from several fields will be mixed to produce a composite oil blend, and sold to market that way under a ‘Marketable Crude Oil Name’, an MCON. For most countries, the availability of data on oilfields in the public domain is limited (Malins et al., 2014). Data is also limited about which fields feed which MCON (see Section 3.3). In general therefore it is not possible to conclusively establish a comprehensive lists of all fields feeding an MCON, nor is data necessarily available to model all of those fields with OPGEE. It is not clear if any global dataset exists which clearly aligns all global MCONS with constituent fields. Such a dataset would require significant resource to develop due to the fragmented and opaque nature of the global industry, and changes over time in the industry as fields are developed and depleted.

The representative fields methodology allows estimates to be made of MCON-level carbon intensities despite this partial availability of data. It is illustrated in Figure 2.1. First, it is determined which oilfields are associated with adequate data to make an estimate with OPGEE (c.f. Section 2.5). Second, those fields are associated with MCONs. Finally, the carbon intensity of the associated fields is combined to produce an MCON intensity. In some cases, a single MCON will be linked to a single field, and the field CI is used as the best estimate of the MCON CI. In many cases, multiple fields are associated to the same MCON, and the MCON CI is calculated as the production-weighted average of the field CIs. This assumes that the contribution of each field to an MCON is proportional to the size of the field – this will not always be true, but in general there is no data available on the actual fractional constituents of each MCON. In a few cases, on field is believed to feed more than one MCON, and that field’s CI will be counted towards all of the MCONs it is linked to based on the **total** production rate at the field.

As noted by Malins et al. (2014), ‘The use of representative fields may, in some cases, result in significant errors in the identification of the average carbon intensity for particular crudes.’ However, without putting in place additional reporting requirements, these are the best estimates possible given the available data.

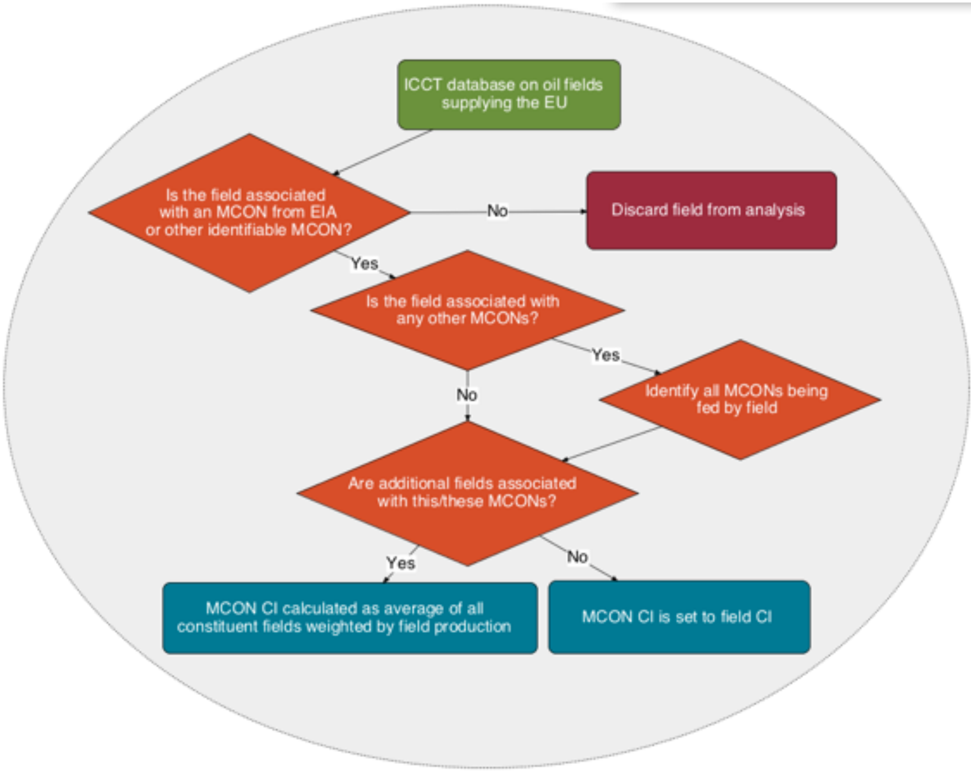

Figure 2.1. Field selection process

2.3.2. Methodology for other feedstocks

Assessment with OPGEE and the representative crudes methodology is appropriate for fuels from conventional crude oil land from bitumen, but is not suitable for other feedstocks, notably gas-to-liquids, coal-to-liquids and kerogen. For these feedstocks, a review has been undertaken of values in the literature, and appropriate average defaults are proposed on that basis (see Section 2.6.8). In principle it would be desirable to apply the same engineering principle-based modeling approach to all crude names and feedstocks, however in practice data limitations and the lack of open source models of some processes limit the ability to do this. We believe that adoption of representative values from the existing literature is the best available approach for assigning average default emissions intensities to these pathways.

2.4. The OPGEE model

The OPGEE is an engineering-based lifecycle assessment tool for the measurement of greenhouse gas emissions from the production, processing, and transport of crude petroleum. OPGEE is a project of Stanford University, with contributions from the California Air Resources Board (CARB) and the International Council on Clean Transportation (ICCT), administered by Dr. Adam Brandt. It has been developed with funding from the California Air Resources Board in support of the California Low Carbon Fuel Standard (LCFS). The CA-LCFS seeks to reduce the carbon intensity (CI) of transportation fuels by 10 percent from the baseline value by 2020. A significant need for CA-LCFS implementation is that the baseline CI of current fuels be constructed using an accurate and robust methodology. OPGEE has been developed to fill a gap in the set of currently available tools for GHG analysis of oil production. Tools like GREET and GHGenius have broad scope, are publicly available and transparent but do not include process-level details. Models such as those used by Jacobs and Energy-Redefined examine processes but are proprietary, and results from these models cannot be reproduced by the public or interested parties. The differences between models are discussed in ore detail by Malins et al. (2014).

The OPGEE model is built in the spreadsheet application Microsoft Excel. Microsoft Excel was chosen as it is widely available, and the use of a spreadsheet interface makes the workings of the model (including all calculations) accessible to most potential users. It also enables the model to remain "open source" and be modified by potential users depending on their requirements. A full explanation of OPGEE is available in the OPGEE documentation (see OPGEE website for the latest version.[25])

The goals of OPGEE development were to:

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.
2. Use detailed data, where available, to provide maximum accuracy and flexibility.
3. Use public data wherever possible.
4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g., refining)

OPGEE is an upstream model - the system boundary extends from initial exploration to the refinery gate. The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional unit is held constant across different production and processing pathways included in OPGEE. This functional unit allows integration with other fuel cycle models that calculate refinery emissions per unit of crude oil processed, and will enable integration with future work on refinery models. The heating value basis can be chosen as lower or higher heating value (LHV or HHV), depending on the desired basis for the emissions intensity. The model defaults to LHV basis for best integration with GREET. All carbon intensities reported here are on an LHV basis. OPGEE includes emissions from all production

[25] https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator

operations required to produce and transport crude hydrocarbons to the refinery gate. Included production technologies are: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion.

Overall, OPGEE includes within its system boundaries more than 100 emissions sources from oil and gas production. However, emissions are subject to significance cutoffs, wherein very small emissions sources are neglected as (likely) insignificant in magnitude. The reason for this is that it would be infeasible (and counter-productive) for regulators or producers to attempt to estimate or model the magnitude of every emissions source. Fortunately, a small number of emissions sources will result in most of the emissions from petroleum production operations. Hence, emissions sources included in the OPGEE system boundary are classified by estimated emissions magnitude. These emissions magnitudes are meant to represent possible emissions magnitudes from a source, not the actual emissions that would result from that source for any particular field. An order-of-magnitude estimation approach is used, with each source assigned a rating in "stars" from one-star (*) to four-star (****) corresponding to 0.01 to 10 g CO_2 eq. per MJ of crude oil delivered to the refinery gate. These classifications are explained in more detail in Table 2.2.

Table 2.2. Emissions magnitudes covered in OPGEE

CLASS	ESTIMATED MAGNITUDE (gCO_2/MJ)	DESCRIPTION
*	0.01	Minor emissions sources not worthy of further study or estimation. This is the most common classification. One-star emissions are ac- counted for by adding a value for miscellaneous minor emissions.
**	0.1	Minor emissions sources that are often neglected but may be included for physical completeness.
***	1	Sources that can have material impacts on the final GHG estimate, and therefore are explicitly modelled in OPGEE.
****	10	Sources that are large in magnitude (though uncommon). Examples include steam production for thermal oil recovery and associated gas flaring. These sources are significant enough to require their own dedicated OPGEE modules.

Emissions estimated to be one-star emissions (*) are not modeled in OPGEE due to insignificant magnitude. Since these small sources are known to have non-zero emissions, they are included in the overall emissions estimate by including a "small sources" term. Two-star (**) sources are included simply or are included in the small sources term. Often, two-star sources are minor in magnitude, but are modeled due to the need to model the physics and chemistry of crude oil production and processing. Three-star (***) sources are explicitly modeled in OPGEE. Four-star sources (****) are modeled in detail with stand-alone modules to allow variation and uncertainty analysis.

OPGEE models oil production emissions in more detail than previous LCA models. For example, the energy consumed in lifting produced fluids (oil, water, and associated gas) to the surface is computed using the fundamental physics of fluid lifting, accounting for lifting efficiencies and pump efficiencies. Increased modeling detail results in an increase in the number of model parameters. All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given field, most of the input values will be set to defaults. In contrast, if detailed data are available, a more accurate emissions estimate can be generated. That said, some defaults require more flexible ("smart") default specifications. For example, the water-to-oil ratio (WOR) is an important parameter influencing GHG emissions. OPGEE includes a statistical relationship for water production as a function of reservoir age. The default exponential relationship is a moderate case parameterized with a variety of industry data. Nevertheless, this relationship does not work well in all cases – for instance, it can give misleading results for giant fields with a very high productivity index (e.g., those in Saudi Arabia). The GOR varies over the life of the field. As the reservoir pressure drops, increasing amounts of gas evolve from oil (beginning at the bubble point pressure if the oil is initially undersaturated). This tends to result in increasing GOR over time. Also, lighter crude oils tend to have a higher GOR. Because of this complexity, a static single value for GOR is not desirable. OPGEE uses California producing GORs to generate GORs for three crude oil bins based on API gravity. All the data required to generate empirical correlations for GOR are not likely to be readily available.

2.5. Data input requirements

Malins et al. (2014) identified a set of key parameters for each field that tend to have the most influence over the modeled carbon intensity in OPGEE. These are: **field age, reservoir depth, oil production volume, number of producing wells, reservoir pressure, API gravity, gas-oil-ratio and water-oil-ratio**. Other models, including JEC have used similar key parameters including crude oil recovery type (primary, secondary, or tertiary), water-oil-ratio (WOR), gas-oil-ratio (GOR), the reservoir depth, and the API of the crude in their analysis (see ICF 2013). For average default estimation, a requirement is put in place that a field must have at least half of these data points available to be used as a representative for any MCON. For actual value estimation by suppliers, a much higher bar for data reporting should be set – this will be discussed fully in the final report.

The OPGEE model is designed so that users can estimate GHG emissions from specific crude feedstocks and production processes by providing a relatively limited number of input parameters. These can be divided into four groups: (i) general field properties, (ii) fluid properties, (iii) production practices, and (iv) processing practices (see Table 2.3). In addition to these parameters, the model includes a number of inputs related to land use impacts, crude oil transport, unit efficiencies, and small-source emissions. OPGEE can function using limited data for a given field by relying on default values and smart defaults. If only a small subset of the required data inputs is available for a given field, then most OPGEE parameters will be set to default values. Because OPGEE was designed for "typical" oilfields with moderate conditions, it works well to estimate energy demand in these cases. However, if OPGEE is applied to a field with extreme characteristics (very high WOR, high GOR, significant amounts of gas reinjection), then OPGEE defaults may be less representative of how that field may actually operate. An example of this is given by El-Houjeiri et al. (2013) for the Alaska North Slope region, where there are unusual surface processing arrangements owing to the very high GOR and remote location with no gas infrastructure.

Hence, for a given field it is impossible to know, a priori, how large the distortion from reliance on defaults will be. Only by accessing more data and customizing OPGEE inputs to match field conditions can one definitively quantify any distortion. In most cases, it is considered likely to be small. For example, El-Houjeiri et al. (2013) observe that for the OPGEE "generic" case (moderate WOR, moderate GOR), OPGEE default assumptions about pump efficiencies, electricity use, pump driver type, and other "secondary" assumptions were responsible for only very small (< 0.5 g/MJ) deviations in model results when varied over reasonable observed values. That is, OPGEE was not sensitive to modeler assumptions about field parameters and equipment. In cases with more extreme production patterns, however, this result may not always hold.

Table 2.3. OPGEE required data inputs

GENERAL FIELD PROPERTIES	PRODUCTION PRACTICES
Field Location Field Depth Field Age Reservoir Pressure Oil Production Volume Number of Producing Wells	Gas-Oil Ratio (GOR) Water-to-Oil Ratio (WOR) Steam-to-Oil Ratio (SOR) Water Injection (Y/N, Quantity) Gas Injection (Y/N, Quantity) N2 Injection (Y/N, Quantity) Steam Injection (Y/N, Quantity) On-site Electricity Generation
PROCESSING PRACTICES	**FLUID PROPERTIES**
Heater-Treater (Y/N) Stabilizer Column (Y/N) Flaring Volume Venting Volume	API Gravity of Produced Fluid Associated Gas Composition

When using OPGEE to model fields with regulatory and other public datasets, it is common that production data will be available in some detail, while little public data will be available on the oilfield configuration and production design. For example, associated gas production will often be reported, which allows computation of the field GOR. However, generally, it will not be reported whether the same field uses an AGR unit to treat the associated gas, and sometimes it is not reported whether the field reinjects the gas, flares it, or sells it to the market. For high-GOR fields, there could be substantial emissions uncertainty associated with these questions.

Similarly, default flaring rates (millions of standard cubic feet per barrel of oil) used in OPGEE to model GHG emissions from gas flaring are calculated using country-level data, which cannot account for variations in field characteristics and practices. These country-level estimates are calculated using data from the National Oceanic and Atmospheric Administration and the Energy Information Administration (Elvidge et al., 2007; Elvidge et al., 2009; EIA, 2010). While data is available for reported flaring emissions in some jurisdictions (e.g. Nigeria), in general it is difficult to obtain field specific flaring data. New satellite data from US and EU agencies (e.g., NOAA) coupled with oilfield location information, could potentially be used to assess and monitor flaring, although it is not yet fully demonstrated that the technology is mature for precise monitoring at the field level. Global flaring data from US satellites are reported to public websites on a nightly basis (see http://ngdc.noaa.gov/eog/).

2.5.2. Default specifications

All inputs to OPGEE are assigned default values for use in the absence of more specific data. The more detailed the data that is available, the more accurate the emissions estimate that can be generated.

Some defaults require more flexible ("smart") default specifications. For instance, the water-to-oil ratio (WOR) is an important parameter influencing GHG emissions. OPGEE includes a statistical relationship for water production as a function of reservoir age. Similarly, for gas-oil-ratio (GOR) OPGEE uses three GOR bins based on API gravity.

2.5.3. Data availability

In general, many input parameters are not available in the public domain for any given oilfield. The fields modeled for this report, for which adequate quantities of data are available to run OPGEE, are an exception. Still, even for these fields many parameters must still be based on defaults.

In its current design, OPGEE describes well-to-refinery gate operations in six stages: (i) exploration and drilling, (ii) production and extraction, (iii) surface processing, (iv) maintenance, (v) waste disposal, and (vi) crude transport. Web sources and public domain data, journal articles, textbooks, and industry references currently provide the basis for the lifecycle modeling of these processes. Table 2.4 provides a summary of the currently cited literature and standards organized by different lifecycle processes for conventional crudes.

Table 2.4. OPGEE references cited by lifecycle process (El-Houjeiri and Brandt, 2012)

LIFECYCLE PROCESS	REFERENCES
	Mitchell, R., Miska, S. *Fundamentals of Drilling Engineering*
	Gidley, J., Holdtich, S., Nierode, D. *Recent Advances in Hydraulic Fracturing*
	Lake, L. *Petroleum Engineering Handbook: Volume I-VI*
	Devereux, S. *Practical Well Planning and Drilling Manual*
	Azar, J., Samuel, G. *Drilling Engineering*

LIFECYCLE PROCESS	REFERENCES
Production	Raymond, M., Leffler, W. *Oil and Gas Production in Nontechnical Language*
	Allen, T., Roberts, A. *Production Operations 1: Well Completions, Workover, and Simulations*
	Lake, L. *Petroleum Engineering Handbook: Volume I-VI*
	Cholet, H. *Well Production: Practical Handbook*
Lifting and Pumping	Takacs, G. *Modern Sucker-Rod Pumping*
	Takacs, G. *Sucker-Rod Pumping Manual*
	Takacs, G. *Gas lift manual*
General Environmental Issues	Wilson, M., Frederick, J. *Environmental Engineering for Exploration and Production Activities*
	Reed, M., Johnsen, S. *Produced Water 2: Environmental Issues and Mitigation Technologies*
Secondary Recovery (Waterflooding)	*Waterflooding. SPE reprint series no. 56*
	Craig, F. *The Reservoir Engineering Aspects of Waterflooding*
	Rose, S., Buckwalter, J., Woodhall, R. *The Design Engineering Aspects of Waterflooding*
Enhanced Oil Recovery	Green, D., Willhite, G. *Enhanced Oil Recovery*
	Prats, M. *Thermal Recovery*
	Jarrell, P., Fox, C., Stein, M., Webb, S. *Practical Aspects of* CO_2 *flooding*
Enhanced Oil Recovery System Details	American Petroleum Institute standards:
	RP 534 - Heat Recovery Steam Generators
Surface operations, Separations and Processing	Chilingarian, G., Robertson, J., Kumar, S. *Surface operation in petroleum production, I & II*
	Manning, F., Thompson, R. *Oilfield Processing of Petroleum. Volume 1: Natural Gas*
	Manning, F., Thompson, R. *Oilfield Processing of Petroleum. Volume 2: Crude Oil*
Crude Transport	Szilas, A. *Production and transport of oil and gas. Part B: Gathering and transport*
	McAllister, E.W., *Pipeline Rules of Thumb: Handbook*
	Miesner, T., Leffler, W. *Oil and Gas Pipelines in Nontechnical Language*
Surface Operations	American Petroleum Institute standards:
	Spec 12J - Specification for Oil and Gas Separators
	Spec 12K - Specification for Indirect Type Oilfield Heaters
	Spec 12L - Specification for Vertical and Horizontal Emulsion Treaters

LIFECYCLE PROCESS	REFERENCES
	RP 50 - Natural Gas Processing Plant Practices for Protection of the Environment
	RP 51R - Environmental Protection for Onshore Oil and Gas Production Operations and Leases
Venting, Flaring, and Fugitive Emissions	American Petroleum Institute standards:
	RP 1127 - Marine Vapor Control Training Guidelines
	RP 1124 - Ship, Barge and Terminal Hydrocarbon Vapor Collection Manifolds
	Publ 1673 - Compilation of Air Emission for Petroleum Distribution Dispensing Facilities
	Std 521/ISO 23251:2006 - Guide for Pressure-relieving and Depressuring Systems
	Std 2000/ISO 28300 - Venting Atmospheric and Low-pressure Storage Tanks
	Std 537/ ISO 25457:2008 - Flare Details for General Refinery and Petrochemical Service
	Publ 306 - An Engineering Assessment of Volumetric Methods of Leak Detection in Aboveground Storage Tanks
	Publ 334 - A Guide to Leak Detection for Aboveground Storage Tanks
Other	American Petroleum Institute standards:
	DR 141- Global Emissions of Carbon Dioxide from Petroleum Sources
	Schmidt. *Fuel Oil Manual*

In addition to the above-cited references, the study relies on various publicly available data regarding emissions factors and specifications for engineering components used in the production of conventional fuels. These include emissions factors from GREET (the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model), oil and gas engine specifications from Caterpillar, Inc., and electric motor attributes from General Electric. The study also relies on country-specific crude oil production data from the Energy Information Agency (EIA) and regional flaring volumes from the National Oceanic and Atmospheric Administration (NOAA) (to determine average regional flaring rates).

Table 2.5. Public data sources currently in OPGEE model (El-Houjeiri and Brandt, 2012)

SOURCE	REFERENCED INFORMATION
GREET	Emissions Factors: Boilers/Heaters, Turbines, Reciprocating Engines, and Flaring with 0.2% Non-combustion
	Fuel Cycles and Displaced Systems for Natural Gas
	Ocean Tanker/Pipeline Transport
	Fuel Specifications (Liquid Fuel Heating Values)
Caterpillar, Inc.	Technical Sheets for Oil and Gas Engines
General Electric (GE)	Technical Sheets for Electric Motors
EIA	Country-Specific Crude Oil Production
NOAA	Country-Specific Flaring Volumes

2.5.4. Publically available datasets for crudes sources to the EU

The OPGEE project aims to "use public data wherever possible", in order to maximize transparency. Notwithstanding this preference, extensive public datasets for crudes consumed in the EU market are available only for British, Norwegian, Danish and Nigerian fields. These datasets are made available via each jurisdiction's energy agency, or in the case of Nigeria from the National Petroleum Corporation (NNPC). Overall, the above-cited datasets contain detailed (monthly) time series data at the field level across a number of parameters included in the OPGEE model. Even so, several important parameters are not included in these datasets and have had to be supplemented from a number of different sources. In particular, because the reports are focused on production data, they do not address the physical characteristics of the fields, including parameters such as field depth (excepting the Norwegian data) and reservoir pressure. A significant source of data is available in the Society of Petroleum Engineers literature, which is available by subscription or by purchase of individual papers (see www.onepetro.org). This database of over 100,000 technical papers represents a key resource to be further utilized in future modeling.

2.6. Review of fossil fuel pathways not modeled by OPGEE

With a projected increase in demand for transportation energy in the future, fossil fuels utilized by the transportation sector are expected to be produced using enhanced extraction technologies, innovative processing technologies, and new feedstocks including unconventional crudes such as tar sands and tight oil (sometimes called 'shale oil'). Anticipating this, the European Commission's proposed Implementing Measure for Article 7a of the FQD (European Commission, 2012) listed disaggregated carbon intensities for tar-sands, coal-to-liquid, and gas to-liquid pathways (EC, 2009) for the purpose of regulating possible increases in GHG emissions from fossil fuel use in the transport sector.

This chapter provides an overview of several fossil fuel pathways and extraction methods that are not currently addressed through engineering modeling in OPGEE. Despite not being treated in the OPGEE model at the same level of engineering detail as conventional crude extraction, there are lifecycle carbon intensity estimates for several of these processes in the existing literature, and it is therefore still possible to assign default average carbon intensity values to these pathways. This chapter discusses system boundaries, technologies, important parameters, data considerations and assumptions and availability, and summarizes the reported carbon intensities from the literature. In addition to unconventional oil feedstocks (kerogen, bitumen, CtL, GtL), innovative processes for extracting conventional crude are discussed (tight oil fracking, CO_2 enhanced recovery, and deep water offshore). For tight oil fracking, it discusses important emissions sources not currently included in the OPGEE model. These include emissions from flowback, flowback disposal, fracking liquid injection, fracking sand and water transport, and upstream emissions of fracking chemicals. This report includes estimates for tight oil fracking obtained by incorporating these additional sources of GHG emissions.

2.6.1. Gas to liquid (GtL) pathway

In GtL, natural gas or methane (including biogas from landfills, anaerobic digestion, etc.) is converted to liquid fuels (e.g., diesel, gasoline, methanol, DME). The first stage of this process is normally methane reforming, in which methane and other molecules are broken down by catalytic reaction to produce syngas. Syngas is a mixture of carbon monoxide and hydrogen. The generation of syngas is followed by catalytic reactions to produce liquid fuels (see Figure 2.2). One such an example is Fischer-Tropsch (FT) synthesis, which produces gasoline, diesel and other products. The gas-to-diesel pathway analyzed in most LCA studies is based on Fischer-Tropsch synthesis. The JEC Well-To-Wheels study reports an upstream carbon intensity of 18.7 gCO_2e/MJ for a Fischer-Tropsch GtL process.

Depending on how natural gas or methane is produced (fracking, conventional production, anaerobic digestion, flaring), the carbon intensities of the liquid fuels produced by GtL vary markedly. The GREET model (c.f. Wang, 1999) shows that diesel derived from avoided landfill methane that would otherwise have been released has a negative carbon intensity of -55 gCO_2/MJ. The negative value is due to avoided methane emissions. Likewise, diesel produced from methane via anaerobic digestion has a lower CI than diesel from natural gas.

While pathways from recovered gas are environmentally preferable, GtL in Europe is likely to be produced from fossil natural gas. For a natural gas to diesel pathway, the Well-to-tank (WTT) carbon intensity (CI) estimate from GREET is 35.6 gCO_2e/MJ with the WTW carbon intensity of about 106.4.1 gCO_2e/MJ assuming combustion emissions of diesel to be 70.8. GREET uses energy-content based method for co-product allocation.

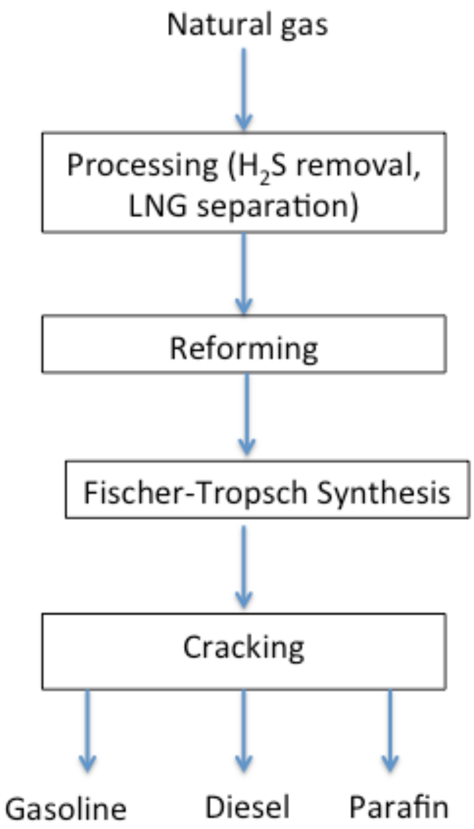

Figure 2.2. Simplified process diagram for a GtL pathway

Forman et al. (2011) of the South African oil company Sasol also estimated carbon intensities for a GtL pathway for natural gas, but using the displacement method for co-product allocation.[26] Their WTW estimates are in the range of 86 to 89 gCO_2 e/MJ, lower than the carbon intensity of US petroleum diesel. These values are also lower than the value reported in the FQD amendment proposal, which is 97 gCO_2/MJ, which is based on the JEC well-to-wheel analysis (JEC, 2011). One possible reason for the observed difference may be due to the energy-based allocation method utilized in the JEC analysis vs. the displacement method utilized by Forman et al. (2011). The displacement analysis presented by Forman is based on a raft of assumptions about the co-products of the GtL diesel process (which include condensate and LPG; naphtha; paraffin; and lubricant base oils). This includes, for instance, assuming that higher quality lubricant base oils from GtL deliver fuel efficiency benefits. In principle, displacement analysis is the preferred co-product allocation approach under the ISO 14040 standard for LCA. However, because displacement analyses require so many assumptions about market dynamics and the carbon intensity of existing products, they can be challenging, and the results can be locally specific. The Forman result assumes a facility based in Qatar, and some displacement assumptions are locally sensitive. JEC (2011) argue that GtL naphtha and LPG will in fact have higher carbon intensities than conventional products, and that therefore a displacement analysis would result in debits, not credits, for these products.

[26] The displacement method involves identifying the materials likely to be displaced by co-products, and assigning carbon credits/deficits accordingly.

The biofuel accounting rules under the RED/FQD require energy allocation accounting of co-products in order to provide a simplified and predictable analysis. OPGEE, on the other hand, does by default use displacement analysis for co-products (although energy allocation is an option). However, the OPGEE displacement assumptions are relatively simple – displacement of natural gas or natural gas-generated electricity, using emissions factors from California GREET. Using a simpler allocation (as in JEC WTW) or a simpler displacement analysis (as in OPGEE) makes results more predictable and prevents displacement assumptions from driving results, but may risk under-crediting genuine environmental benefits from the fuel production system. Additional assessment by lifecycle analysts of the potential secondary environmental benefits of developing GtL technologies will allow firmer conclusions to be drawn about the true magnitude of displacement benefits.

For reporting under the FQD, it is proposed that the JEC WTW study is an appropriate basis for setting the average default upstream carbon intensity value, which should therefore be set at 18.7 gCO_2e/MJ. Note that because there is no refining step as such in the GtL process, the full carbon emissions of GtL production are included in the upstream phase. The full lifecycle emissions of GtL production are more comparable to the full lifecycle emissions of a conventional diesel pathway.

2.6.2. Coal to liquid (CtL) pathway

A coal-to-liquid conversion is more energy intensive than a gas-to-liquid conversion because coal has to be gasified to syngas and more carbon is used for generating hydrogen than in a natural gas to liquid pathway. In a coal-to-liquid pathway, coal is gasified and the resulting syngas is cleaned. The cleaned syngas is subjected to the Fischer-Tropsch (FT) Synthesis in the presence of iron catalysts (see Figure 2.3). The resulting FT products are separated and upgraded to derive a variety of end products such as diesel, naphtha, jet fuel, and paraffin. The JEC WTW report gives upstream emissions of 129 gCO_2e/MJ for coal-to-liquids – the upstream stage is thus more carbon intensive than the full lifecycle of conventional fuel production.

According to the GREET model, feedstock production and fuel production and transport alone generate 109 gCO_2e per MJ of diesel produced, compared to 36 gCO_2e for a GtL pathway. Assuming combustion GHG emissions of diesel to be 70.8 g CO_2e/MJ, the GREET WTW emissions would be 179.8 g CO_2e/MJ. The coal extraction and transport contributes about 5.3 gCO_2e per MJ of coal. A similar conclusion was reached by Jaramillo et al. (2009) who found that emissions from coal extraction plus fuel production are 113 gCO_2e/MJ with a well-to-wheel carbon intensity of 182 gCO_2e/MJ. Hence, on a well-to-wheel basis, gasoline and diesel produced from CtL has twice the CI of gasoline and diesel from crude oil. The well-to-wheel carbon intensity of CtL fuel suggested in the proposed amendment to the FQD is similarly high, i.e. 172 gCO_2e/MJ (European Commission, 2012).

In principle, it would be possible to reduce the well-to-wheel emissions of a coal to liquid pathway by using carbon capture and sequestration, but it will increase the costs of fuels, which are already costly compared to conventional fuels. For example with carbon capture and sequestration, the CI of diesel decreases from 182 gCO_2e/MJ to 108 gCO_2e/MJ in Jaramillo et al. (2009). Likewise, according to EC (2009), with carbon sequestration, the CI of a CtL pathway decreases from 172 gCO_2e/MJ to 81 gCO_2e/MJ. While CCS is a possibility for CtL, as for many other technologies, it has not yet been deployed for any commercial CtL operation and it would be premature to assume that such deployment is likely in the short to medium term.

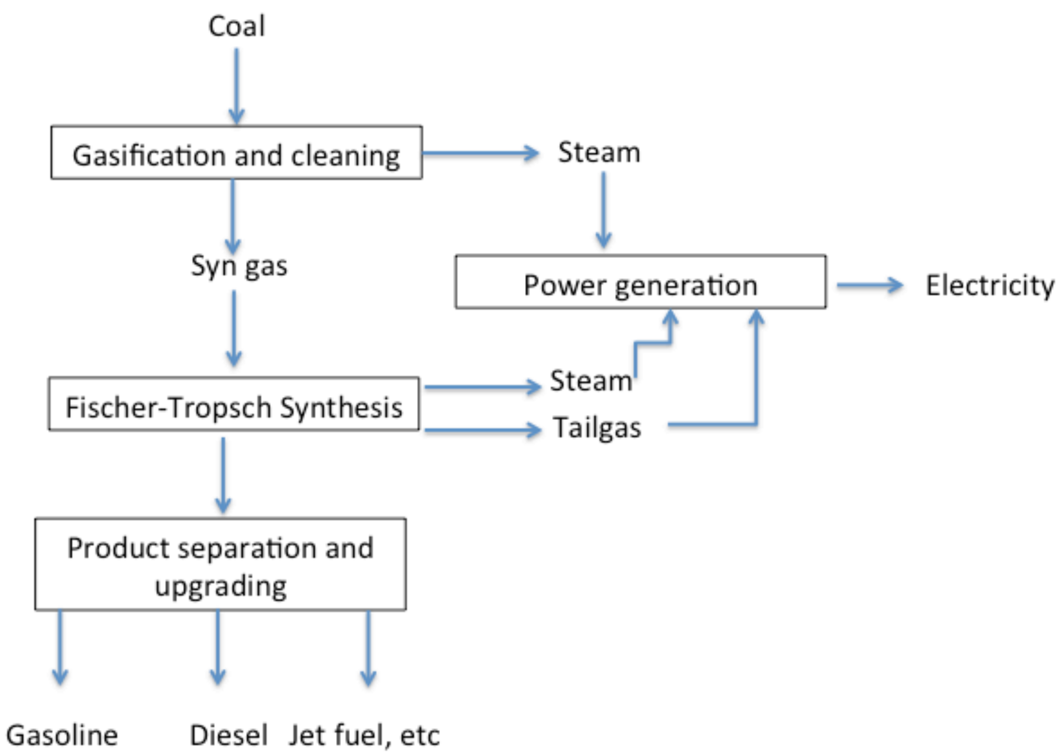

Figure 2.3. Simplified process diagram for a coal to liquid pathway

It is apparent from the literature review that the CtL pathway is highly carbon intensive. The JEC WTW value of 129 gCO_2e/MJ for the upstream emissions is considered an appropriate basis for the average default upstream emissions value for reporting under the FQD.

2.6.3. Oil shale

Oil shale, a form of unconventional oil, is derived from kerogen present in inorganic rock (shale ore). Kerogen is an organic compound, which is a precursor to bitumen and crude oil. One ton of shale ore can produce between 10-60 gallons of oils, along with HC gas and petroleum-coke-like “char” (Hendrickson, 1975).

Kerogen is converted to oil via retorting processes. In retorting, the shale ore is heated in the absence of oxygen to produce liquid, gaseous, and solid hydrocarbons. Retorting is also known as pyrolysis. Retorting produces coal-like shale char along with pyrolysis oil and gas. The oil fraction can then be processed to produce diesel, jet fuel, kerosene and other products. Oil derived from kerogen tends to be rich in heteroatoms (N, S, metals) and is unstable. It is therefore generally upgraded (via hydrogen-addition processes) before being sent to a conventional refinery. The composition of kerogen-derived gases varies widely (Hendrickson 1975) depending on the process used, process temperatures, and rates of carbonate mineral decomposition. In processes where significant carbonate decomposition occurs, the resulting gas stream can have high fractions of CO_2, resulting in a poor quality gas of low heating value (Brandt 2009).

A key driver of the environmental impacts of fuel production from kerogen is the retorting of raw shale to produce liquid hydrocarbons. The time and temperature requirements of retorting vary: high temperature retorting results in rapid conversion, while low-temperature retorting requires more reaction time. Examples of this variation are given by Brandt (2008, 2009): the Shell in situ conversion process heats shale over a period of ~2-3 years to 340-400^{O}C, while the aboveground Alberta Taciuk Processor heats shale to ~500^{O}C, with a reaction time of minutes. While faster reactions require higher temperatures (and therefore more energy input to the shale), another factor that affects emissions is that at very high temperatures, such as those resulting during combustion of spent-shale char, carbonate minerals such as calcite and dolomite ($CaCO_3$ and MgCa $(CO_3)_2$, respectively) will decompose into their associated metal oxides and CO_2 (CaO and $MgCaO_2$, respectively). This mineral CO_2 can be a significant contributor to emissions from some oil shale production processes (Brandt et al. 2010).

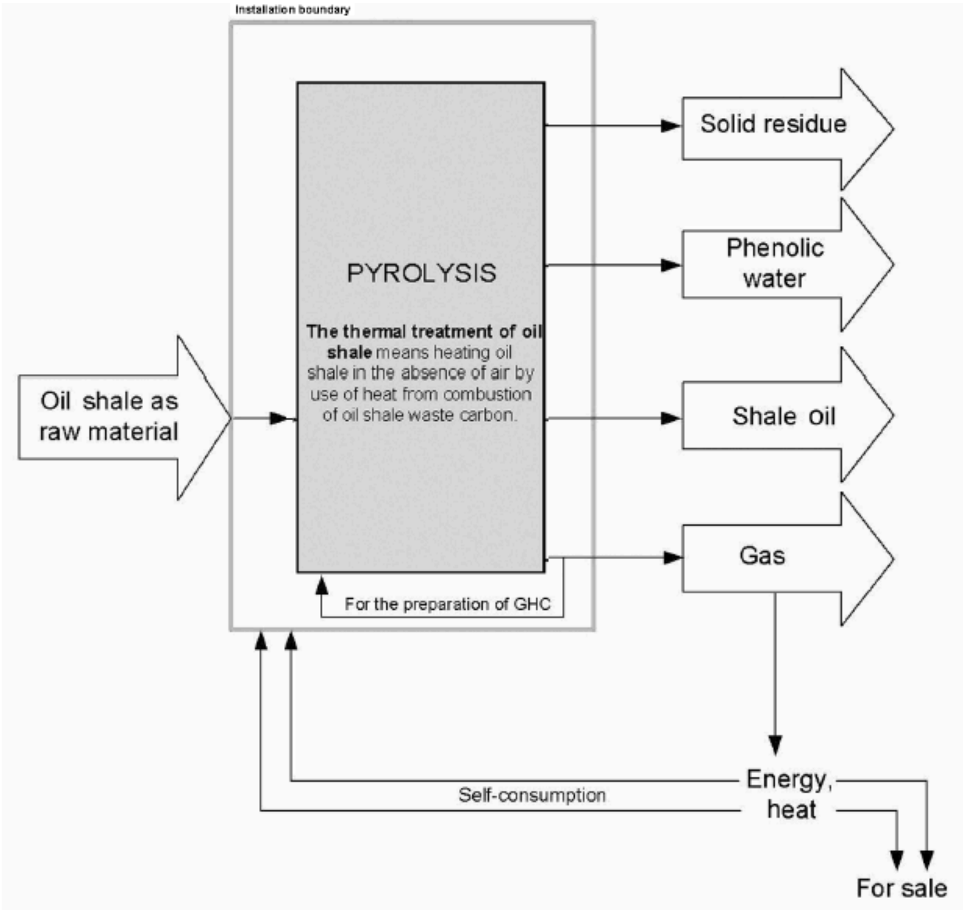

Figure 2.4. An illustration of the retorting process (Siirde et al., 2013).

There are two ways of converting oil shale to gaseous and liquid fuels. In *ex-situ* retorting shale oil is mined and sent to the retort aboveground. Alternatively, *in-situ* retorting involves the heating of oil shale underground and recovering the shale oil through vertical wells drilled into the formations. In-situ retorting is still being developed. Ex-situ retorting is the only commercially used method of producing shale oil. Production of refined products from oil shale involving ex-situ retorting involves GHG emissions from the following major production steps.

(1) surface mining and transport;

(2) retorting;

(3) upgrading and refining; and

(4) disposal of spent shale.

Well-to-wheel emissions may vary depending on the quality of shale oil (kerogen content, mineral content, etc.) and retorting technology used. The results of the analysis may also be sensitive to choice of co-product allocation method. Estimates of well-to-wheel life cycle emissions of shale oil can be as high as 159 gCO_2e/MJ (Boland and Unnasch, 2013). Two studies by Brandt et al. (2009, 2010) show that oil shale-derived fuels can have 25-75% higher GHG emissions compared to conventional liquid fuels. The differences in CI estimates come from the variation in the shale quality and retorting technologies used. Brandt et al. (2009) modeled the Alberta

Taucik Processor. Retorting, upgrading and refining of raw shale oil are the main sources of upstream emissions. GHG emissions from mining are relatively small.

In addition to emissions from process energy consumption such as electricity produced from oil shale or direct use of oil shale for energy, there are non-process-energy CO_2 emissions as well. Oil shale contains a small amount of oxygen, which reacts with the carbon present in the shale during retorting to produce CO_2.

As noted above, there are CO_2 emissions from thermal decomposition of inorganic carbonates present in the shale oil. Brandt (2009) and Siirde et al. have taken into account CO_2 releases from inorganic carbonate decomposition during retorting, which is a material, not an energy source. Carbonates present in oil shale begin to decompose at lower temperatures (560^{O}C) than when they are present as a pure chemical such as dolomite (Sharp et al., 2003). The specific rates of decomposition of carbonate minerals have been examined experimentally for green river oil shales (see sources in Brandt 2009), while different rates may apply to Estonian shales due to their different composition.

The most comprehensive study of Estonian oil shale emissions to date is that of Siirde et al. (2013). This study is compared with previous studies of emissions from retorting Green River oil shale (e.g., Brandt 2008, Brandt 2009, Brandt et al. 2011).

Estonian oil shale, also called Kukerisite shale, is present in a thin-bed deposit (2-3 meters thick), which is comprised of interbedded carbonate, and sandy-clay/organic layers (Arro et al. 2003). In contrast, the Green River oil shale is very thick (hundreds of meter thick) with many layers and varying quality over the depth of the deposit (Hendrickson 1975). The chemical compositions of these shales are compared in Table 2.6.

In Estonia, two key processes are used to process oil shale, with the process chosen depending on the shale grade. The Kiviter process uses combustion gases to carry thermal energy from the combustion zone to the unretorted shale (Siirde et al. 2013), so it is classified as a gaseous heat carrier (GHC) technology. Kiviter technology is an internal-combustion, vertically-oriented retort, where combustion gases move in counter-flow direction compared to the movement of shale. Unretorted shale is loaded at the top of the retort. As the shale moves downward, upwelling combustion products transfer heat to the shale retorting it. Products are drawn off and condensed at the top of the retort. At the bottom of the retort, air is introduced, combusting produced gases and char (~900^{O}C). The high temperatures achieved result in some carbonate decomposition.

Table 2.6. Compositional differences between Estonian and US oil shales

COMPONENT	KUKERISITE (ESTONIA)[A] (%)	GREEN RIVER (USA) (%)	NOTES
Organic	24.9%	16%	b
- C	77.45	80.52	c
- H	9.70	10.3	c
- O	10.01	5.75	c
- N	0.33	2.4	c
- S	1.76	1	c
- Cl	0.75	-	c
Sandy-clay	23.9%	39%	c
- SiO2	59.8	66.2	c
- Al2O3	16.1	16.5	c
- FeS2	9.3	-	c
- K2O	6.3	2.5	c
- F32O3	2.8	6.6	c
- H_2O	2.6	-	c
- Other	3.1	8.1	c
Carbonate	39.8%	39%	d
- CaO	48.1	40.9	e
- MgO	6.6	12.8	e
- FeO	0.2	-	
- CO_2	45.1	46.2	e
Moisture	11.4%	5%	f

Notes
a – Gross composition from Siirde et al. (2013). Detailed composition of components from Arro et al. (2003a, Table 2).
b – Organic matter fraction from 26.7 gal/ton shale, as modeled in Brandt (2009) for ATP retort.
c – Data from Hendrickson (1975, p. 47)
d – Estonian carbonate fraction not reported directly in Siirde et al. (2013), but calculated by difference from other major components. Aligns well with back-calculation from reported CO2 content. Green River carbonate composition from Hendrickson (1975, p. 33) for 28 gal/ton shale, which is closet to modeled shale for ATP retort modeling.
e – CaO, MgO and CO2 makeup from fractions calcite, dolomite (Brandt 2009), and chemical formulas of each.
f – Estimate from Brandt (2009), based on data from OSEC for mined Green River oil shale

The Petroter process (known in earlier incarnations as the Galoter process) is a solid heat carrier (SHC) process. Spent shale char is combusted to provide process fuel, and the resulting hot spent shale ("ash") is mixed with incoming shale to transfer heat. The newest incarnation of this technology is the Narva Enefit-280 plant, opened in 2012 in Estonia (Enefit, 2014). Because of its SHC technology design, the Petroter family of processes has some resemblance to the Alberta Taciuk Processer (ATP) modeled by Brandt (Brandt 2009).

Input and product properties can be compared for the Petroter SHC and ATP processes, as shown in Table 2.7. The Green River shale has significantly lower heating value per tonne of shale (58% of the heating value of Estonian shale), and therefore has less oil yield (75% of the oil yield) and gas yield (22% of the gas yield). This difference in heating value is aligned with the differences in organic content noted above. These differences could be responsible for significant per-energy-content CO_2 emissions.

Table 2.7. Yield and heating value differences between Estonian and US oil shales.

	UNIT	PETROTER (SIIRDE ET AL. 2013)	ATP (BRANDT, 2009)	NOTES
Shale heating value	MJ LHV/tonne	8.17	4.71	a
Retort oil yield	kg/tonne shale	120	91	-
Retort gas yield	m^3/tonne shale	35	18	b
Oil heating value	MJ LHV/tonne shale	4956	3757	c
Gas heating value	MJ LHV/tonne shale	1225	267	d

a - Assume LHV is 0.9 of reported HHV for Green River oil shale used in Brandt (2009)
b - Convert all gas leaving retort zone to moles and Nm3 using 22.4 L/t at 0C
c - Green River crude shale oil HHV of 44 MJ/kg and LHV/HHV ratio of 0.93
d - Gas heating value for ATP much less than Petroter (15 MJ/m3 compared to 35 MJ/m3) based on detailed gas composition data output from Brandt (2009)

GHG emissions from Estonian oil shale processing have been calculated for SHC and GHC technology by Siirde et al. (2013). The authors found that the Petroter process resulted in higher emissions of 38.7 gCO_2 per MJ of Estonian shale oil produced (not including upgrading and refining) as compared to 30.9 gCO_2/MJ associated with the Kiviter process. Of these values, the Petroter process is more comparable to the work of Brandt on the ATP reactor (also a SHC technology). In the ATP case, emissions up to retorting range from about 45 gCO_2/MJ to 65 gCO_2/MJ. Siirde et al. (2013) argue that the difference is due to different assumptions and system boundary, omission of co-product allocation and mixing the results from materials and energy LCA.

The results from Siirde et al. and Brandt are compared in Table 2.8. Upon first investigation, it appears that the Petroter figures are much lower than the ATP figures. However, Siirde et al. allocate a significant amount of emissions to the produced HC gas. Siirde et al. note that upstream emissions (extraction and retorting) per MJ of total product produced (oil + gas) are 38.7 g/MJ, closer to the Brandt range of 50-64 g/MJ for mining, transport, and retorting. The allocation scheme in Siirde et al. is uncertain and not well documented. Note that in Siirde et al. the gaseous HC is assigned 2/3 of the emissions (see Table 2.8 below), but only represents 20% of the energy content of the process outputs (see Table 2.7 above). It is not clear if an economic allocation process is assumed, or perhaps some other allocation scheme is used. Note that the Brandt ATP retort does not export gas, as all gas is assumed to be used on-site for retorting or to produce electric power to run equipment.

Because of the poor quality of the oil produced from the retorting process (as it has high organic oxygen, nitrogen and metal contents), the usual practice is to upgrade shale oil before sending it to a refinery. Upgrading is done in hydrotreaters using hydrogen and catalysts. As a result upgrading and refining of shale oil requires more energy than refining of crude oil. While retorting emissions reported in Siirde et al. are lower than those of Brandt, upgrading and refining emissions from Siirde et al. are higher than Brandt. Based on data provided by Aarna, and Lauringson (2011) and Spath and Mann (2001), Siirde et al. (2011) estimate GHG emissions from shale oil upgrading to be 18.2 gCO_2/MJ diesel, and 5.1 gCO_2/MJ diesel from refining. This total of 23.3 gCO_2/MJ is significantly higher than the Brandt range of 9.4-17.4 gCO_2/MJ.

Table 2.8. Comparison of emissions from ATP reactor and Petroter reactor

	UNIT	PETROTER (OIL)	PETROTER (GAS)	PETROTER (TOTAL)	ATP - LOW	ATP - HIGH
Mining and processing	g/MJ refined product	0.51	2.02	2.53	4.00	8.6
Transport	g/MJ refined product	0.33	1.32	1.65	0.2	0.5
Retorting	g/MJ refined product	10.7	26.9	37.6	46.6	55.6
Upgrading	g/MJ refined product	18.2	-		1.1	6.2
Refining	g/MJ refined product	5.1	-		8.3	11.2
Well to-tank emission	g/MJ refined product	34.84			60.20	82.10[a]

[a] - For the Petroter (Oil) column, we sum upgrading and refining emissions to upstream emissions, due to lack of data on diesel yield.

Some of the variation between these results can be understood. One significant difference is the difference in shale heating value and HC yield. Because of the lower yield of Green River oil shale, more inert rock must be heated per unit of oil output. For this reason alone, we would expect Green River oil shale to have higher emissions than Estonian oil shale. Another significant difference is the allocation scheme, wherein Petroter emissions are allocated heavily to the gaseous product. However, without significant additional technical modeling, it is very difficult to determine the exact reasons for differences between the ATP and Petroter process emissions. Emissions from shale processing practices are very sensitive to shale chemistries, process design (temperature profiles) and assumptions about the external system (e.g. for credits and debits). Exploration of these effects is beyond the scope of this report.

To sum up, WTW emissions of petroleum fuels produced from oil shale depends mainly on the characteristics of oil shale and retorting technologies used to process oil shale. A review by Brandt (2010) indicates a range of WTW emissions from about 110 gCO_2e/MJ to 160 gCO_2e/MJ. The Siirde et al. study (2013) on Estonian shale oil suggests a significant amount of gas production as a co-product during retorting. This can lead to a significant reduction in WTW emissions from 125 gCO_2e to 107 gCO_2e/MJ. However, additional studies are required to verify the production of significant amounts of gas and a more transparent and rigorous method of allocation should be used to accurately estimate GHG emissions of Estonian oil shale.

A recent study conducted by Jacobs Consultancy for Enefit (Aarna and Lauringson, 2011) reports a carbon intensity of 128 gCO_2e/MJ for liquids derived from Estonian oil shale. This result along with those reported by Siirde et al. (2013) and Brandt et al. (2009) suggest that 130 gCO_2e/MJ is an appropriate estimate of the WTW carbon intensity of liquid fuels from Estonian oil shale, of which the upstream portion represents 52 gCO_2e/MJ.

2.6.4. Tight oil fracking

In recent years there has been a rapid surge of interest in hydraulic fracturing (or 'fracking') to produce oil and gas. The available literature on hydraulic fracking mostly deals with shale gas production in the US. There are very few LCA studies on tight oil fracking (we are only aware of Boland and Unnasch, 2013, although CARB, 2013 present an estimated lifecycle carbon intensity for Bakken crude that excludes some fracking-related emissions sources). Tight oil fracking is currently being carried out in the Bakken formation in North Dakota, as well as the Permian basin of Texas. Boland and Unnasch (2013) estimated life cycle emissions of tight oil including additional emission sources that are not currently modeled in OPGEE, such as emissions from the fracking process itself.

Tight oil refers to oil trapped in rock formations with extremely low-permeability, which prevents the free flow of oil. These rocks are located at unminable depths and are rich in organic material known as kerogen, as well as oil and gas in very small pores. In tight oil fracking, vertical drilling is generally followed by horizontal drilling in the rock formation. In some locations, (e.g. Texas Permian Basin or California) vertical wells are fractured. This is followed by the injection of highly pressurized fracking fluid, which creates cracks or restores cracks in the rock layer. The overall result is the increase in the mobility of trapped oil and gas, and allowing these resources to be extracted. Injection of fracking fluid is done at the well completion stage; the used fracking liquid is recovered and disposed of or recycled for future use. Fracturing fluids are primarily made of water, with proppants included in the fracking fluid that lodge in the fractures and ensure that the fractures remain propped open so that oil and gas can flow freely into the wellbore.

Fracking fluid consists of about 90% of water, and 9.5% sand, and 0.5% chemicals. The actual composition varies from one well to another (Fracfocus.com).

Chemicals used in fracking fluids serve a variety of purposes. These chemicals can be broadly categorized into six categories – acids, biocides, corrosion inhibitors, friction reducers, gelling agents and oxygen scavengers. Potentially, a large number of chemicals are available for use in each category, but in real practice, only limited numbers of chemicals from each category are utilized. Chemical categories, their use, and a few examples are shown in Table 2.9.

Table 2.9. Examples of chemicals used in fracking liquid

CHEMICAL CATEGORY	USE	EXAMPLES
Acid	Removes near well damage	HCl
Biocides	Inhibits bacterial growth	Glutaraldehyde, Quaternary ammonium chloride
Corrosion inhibitor	Prevents corrosion of pipe	Methanol, formic acid, isopropanol
Friction reducers	Lowers pump friction	Polyacrylamide, Methanol, Ethylene glycol
Gelling agents	Improves proppant placement	Guar gum, ethylene glycol, methanol
Oxygen scavenger	Prevents corrosion of well tubulars by oxygen	Iron and sodium chloride

Water consumption in high-volume, horizontal drilling plus hydraulic fracking ranges from 1-5 million gallons per well. In regions where vertical wells are fractured, water use tends to be smaller (e.g., California).

Depending on the use of produced gas and flaring efficiency, Boland and Unnasch (2013) estimate that flaring can contribute somewhere between 5.2 to 12 gCO_2 e per MJ of gasoline produced.

In a separate study of Marcellus gas production, Jiang et al. (2011) used the combination of available emission raw data and emission factors and EIOLCA to estimate GHG emissions from each stage/process. For example, to calculate emissions from chemicals used in fracking, it uses the costs of chemicals to derive emissions from EIOLCA using industry sector specific $ to emission ratios. Note that such an approach would only give approximate GHG estimates. Although the authors did not provide estimates of emissions associated with chemicals, they reported emissions for hydraulic fracturing of 0.35 gCO_2e per MJ of natural gas produced. This suggests that the contribution of fracking chemicals to WTW emissions is likely to be small for oil fracking as well.

According to Jiang et al. (2011) the preproduction step, which consists of well pad preparation, drilling, hydraulic fracturing, and completion, contributes about 1.8gCO_2e/MJ (Table 2.10). Since the pre-production stage of tight oil fracking is likely to be similar to that of as fracking, it is not unreasonable to expect a similar scale of contribution to tight oil fracking from preproduction.

Santoro et al. (2011) on the other hand calculates the total tonnage of chemicals in the fracking liquid based on the chemical composition and the expected volume of water consumed, which is about 19.63 $*10^6$ L. For upstream emissions of chemicals, the emission factor for the US organic chemical industry has been used as proxy (Ozalp and Hyman, 2009). They also estimate emissions associated with land clearing for a well pad, access road, and gathering line construction. This includes both initial carbon loss and forgone carbon sequestration. Santoro et al. (2011) estimate emissions from preproduction at 0.42 gCO_2e/MJ. This also confirms that emissions associated with fracking chemicals are likely to be relatively small on a lifecycle basis.

There is a high degree of uncertainty regarding the extent of methane emissions from unconventional natural gas and tight oil wells. For shale gas fracking, fugitive emissions per well have been estimated assuming either all wellbore fugitive emissions are vented or that most fugitive emissions are captured. According to a gas industry group, 93% of fugitive emissions from the wellbore are captured (ANGA, 2012). However, according to Sullivan and Paltsev (2012), current industry practice is to capture 70% of fugitive emissions, with 15% flaring and 15% venting. Based on this approach, fugitive methane emissions range from 35.1 metric tonnes to 151.3 metric tonnes per well. Overall for a 15-year lifetime, fugitive emissions account for 0.52%-0.99% of total gas recovered.

A recent study by Allen et al. (2013) performed the first experimental assessment of hydraulic fracturing flowback and fugitive emissions. This study found that reduced emissions completions, or RECs (sometimes known as green completions technologies) resulted in 99% capture or control of flowback emissions. However, the prevalence with which RECs are applied to tight oil production is poorly understood, and the application of RECs to tight oil production is not currently regulated by the U.S. EPA.

Recent studies by EPA (2010) and Jiang et al (2011), suggest even higher rates of methane emission per well with 177 tonnes and 400 tonnes, respectively.

Table 2.10. Reported emissions (gCO_2/MJ) from various stages of fracking and distribution

	GAS FRACKING		OIL FRACKING
	Jiang et al. (2011)	Santoro et al. (2011)*	Boland and Unnasch, 2013
Preproduction	1.8	1.5	NA
Production	9.6	2.2	NA
Subtotal	11.4	3.7	9-18
Processing	4	1.9	
Transmission and distribution	2.5	0.6	4-7

*Without including fugitive methane emissions.

By incorporating these additional emission sources, Boland and Unnasch (2013) report a preliminary estimate of extraction and transport emissions to be in the range of 13 to 25 gCO_2e/MJ. Including downstream emissions and combustion, they suggest that well-to-wheel CIs would be in the range 98 to 112 gCO_2e/MJ for Bakken oil fields. It is not clear whether all of the assumptions in the paper are warranted. For example, the assumption that transport of Bakken crude occurs from North Dakota to the U.S. East Coast or California by truck is incorrect (rail is used), resulting in high transport emissions of 4-7 gCO_2e/MJ. The breakdown of WTW emissions is as follows:

- oil production: 9-18 gCO_2e/MJ;
- crude transport: 4-7 gCO_2e/MJ[27];
- refining: 10-12 gCO_2e/MJ[28];
- combustion: 73.5 gCO_2e/MJ.

However, the methodology used to derive these numbers is not well documented, and it is difficult to explain the emissions at the high end of the range given based on information in the paper.

The current California ARB estimate using the OPGEE model for upstream emissions (not including refining) of tight oil fracking is 7.9 gCO_2e/MJ (ARB, 2013), which is based on Bakken Oil fields in North Dakota. However, this estimate does not take into account other potential sources of fracking emissions including fugitives and flowback from the wellbore, flowback disposal, energy use at the hydraulic fracturing stage, and emissions from transporting fracking sand and water. ARB do however include flaring emissions with a flaring rate of 380 scf/bbl. This is higher than the average flare rate for Russia or Iraq, but only about 60% of the average flare rate for Nigeria.

For this report, guideline estimates have been made of GHG emissions from additional sources of emissions not included in the current version of the OPGEE model. These sources are listed in Table 2.11.

[27] Boland and Unnasch (2013) attribute higher transport emissions to transport of crude oil from the Williston Basin to California or East Coast by trucks.
[28] Boland and Unnasch (2013) calculated refining emissions to reflect the process units used for refining and also incorporated complete fuel cycle emissions associated with energy inputs such as natural gas and pet coke.

Table 2.11. **Sources of emissions from additional steps/processes not included in the current version of the OPGEE**

SOURCES	PARAMETERS/DATA SOURCES
Fracked sand and water transport and disposal	Transport distance and mode, quantity of water and sand required per fracking
Upstream emissions of fracking chemicals	Amounts and types of chemicals used and emission factors
Fugitive emission from fracking, flowback emissions and flowback disposal	Based on the method used by O'Sullivan & Paltsev (2012), and from Allen et al. (2013)
Combustion emission in fracking	Fuels and electricity used in drilling and injection, injection pressure, drilling distance

Table 2.12 shows the preliminary estimates of emissions from various processes involved in tight oil fracking and crude transport. The total upstream emissions from tight oil fracking in the Bakken are 9.45 g CO_2e/MJ after incorporating additional sources of emissions, an increase of 1.55 g CO_2e/MJ from the ARB result. This suggests that an additional 1.5 gCO_2e/MJ approximate correction factor should be added to the OPGEE-modeled carbon intensity of tight oil from any other regions. Note that these emissions are still lower than those estimated by Boland and Unnasch (2013). This analysis assumes that the average life cycle productivity of a Bakken oil field is 256,000 barrels of oil (USDA, 2012), as opposed to 130,000 barrels used as a default value in the current version of the OPGEE model. Amounts of water and sand used in fracking liquid injection are 2 million gallons and 1,059,912 kg, respectively. Fracking liquid is injected at a pressure of 7973 psi. The vertical and horizontal drilling distances are 11,000 ft and 10,000 ft respectively, and energy intensity for horizontal and vertical drilling is assumed to be the same.

As can be seen from Table 2.12. venting and flaring alongside drilling and injection are the two largest sources of GHG emissions in tight oil fracking, accounting for 60% of the total emissions. Flowback and flowback disposal account for about 6%.

Table 2.12. Upstream GHG emissions from tight oil fracking in a typical Bakken oil field

PROCESSES	Carbon intensity contribution gCO_2e/ MJ
Drilling + injection	1.55
Oil production	0.88
Steel+ cement production	0.18
Frac chem. + sand production	0.01
Processing	0.76
VFF	4.08
Misc.	0.50
Flow back + flow back disposal	0.54
Off-site emissions	-0.51
Transport (water + sand + chemicals + water disposal + steel + cement)	0.57
Crude transport	0.89
Total emissions	**9.45**

Assuming that refining emissions and combustion emissions are 11 g CO2e/MJ and 73.3 g CO2e/MJ respectively, this preliminary results suggest that the likely WTW carbon intensity of the refined petroleum fuel obtained from tight oil fracking is about 95 g CO2e/MJ. Since the reported refining emissions for European refineries are lower (7-9 g CO2e/MJ), (JEC, 2011) it is possible that fuels produced from tight oil refined in Europe would have lower lifecycle carbon intensities.

2.6.5. Tar sands

Tar sands are included in the OPGEE model, but not at the same level of engineering detail as is available for conventional oil extraction. The results are based on reported data on the energy intensity of tar sands production in Canada, and allow the use of only a single emission factor for upgrading.

Tar sands are extracted in two ways – surface mining and in-situ production. In surface mining, tar sands are mined with large-scale equipment. The bitumen is separated from sand using hot water/steam and the sand remnants are pumped into tailing pits. A commonly used in-situ method for tar sand production is the Steam Assisted Gravity Drainage (SAGD) process. Here, steam is injected into the tar sands located underground, which reduces the viscosity of the bitumen and allows it to flow into production wells.

Due to high viscosity and the high levels of impurities present in mined bitumen, it is generally not suitable for refining without additional treatment. As a result mined bitumen, and some in-situ bitumen, is transported to an upgrader where it is upgraded to synthetic oil before it is refined.

In tar sands extraction, diesel is used by the mining equipment, and electricity is used for pumping, separation equipment and other utilities. Large quantities of steam are required for SAGD operations, and for the surface separation of bitumen from tar sands. There are a number of ways by which steam can be produced: conventional steam generators; combustion turbines with cogeneration; or from the combustion of heavy oil residue. In Canada, oil companies are required to report energy consumption and GHG emission data. Hence data on tar sands extraction and upgrading are readily available. See supplemental information from Englander et al. (2013) for a comprehensive list of oil sands data sources.

Steam production from oil sands operation produces electricity as a co-product, and hence the CI values for tar sands oil can be affected by co-product allocation assumptions. As this co-production of electricity is small (Englander et al., 2013), the results for oil sands emissions are not highly sensitive to assumptions about the electric grid.

Some reported extraction plus upgrading emissions for tar sands in the literature are:

> *Bergerson et al. (2012): 23.9 gCO_2 e/MJ RFG for surface mining dilbit pathway to 38.9 gCO_2e/MJ RFG for SAGD SCO pathway.*
>
> *GREET: 24.4 gCO_2e /MJ for in-situ production and 26 gCO_2 e/MJ open surface mining. Both production processes use upgrading.*
>
> *ARB (with OPGEE): 18.7 to 24.5 gCO_2e/MJ.*

As mentioned above OPGEE uses a single emission factor for bitumen upgrading. Bitumen can have varying API (7°-12° API), which can influence the energy consumption and GHG emissions. Also the resulting synthetic crude oil from upgrading can have a range of API depending on how upgrading is done, with synthetic crudes ranging from heavy to light. Developing a range of emission factors for a range of API transitions would be a valuable exercise, but it would requires extensive modeling and data analysis and is beyond the scope of the present study. Keesom et al. (2009) have shown that the API of crudes including bitumen may correlate with hydrogen consumption. Since hydrogen consumption directly contributes to energy intensity, and hence GHG emissions, it may be possible to use the Keesom et al. regression equation to differentiate emissions of bitumen or SCO with different APIs. It is to be noted that Keesom et al. did not found as good a correlation between API and hydrogen consumption for SCO, but this is inconclusive since Keesom et al. (2009) have only two data points for SCO.

In general, a relationship between oil gravity and refinery energy consumption has been noted in multiple sources. Most recently, work for the GREET model has created a functional relationship between API gravity and the GHG intensity of refining. As the crude (or SCO) becomes heavier, more hydrogen is required for refining, increasing emissions.

Englander et al. (2013) have noted that significant efficiency gains have occurred in upgrading in the last 40 years, such as from process optimization and heat recovery improvements. They argue that improvements in upgrading along with an increasing share of in-situ production and a shift towards increased refinery capabilities to process bitumen mean that upgrader emissions will not be as important in the future.

In conclusion, no amendment is proposed to the existing OPGEE treatment of tar sands extraction at this stage. However, identifying a relationship between the API transition and energy intensity of bitumen upgrading should be a priority for future work.

2.6.6. CO2 enhanced recovery

In CO_2 enhanced recovery, CO_2 is injected into oil wells under supercritical conditions (transported at pressures above the critical point). CO_2 exists as fluid in a supercritical phase at pressure > 6.9 MPa (1087 psi) and temperature > 31°C. In a supercritical phase, CO_2 has a high density and low viscosity, and can dissolve materials like a liquid, but effuse through solids like a gas. When injected, CO_2 acts as a solvent to recover oil trapped in the reservoir rock and provides a gas pressure drive as well as reducing viscosity to drive the crude flow toward the well bore head. CO_2 enhanced recovery is a tertiary extraction method, and is used only after primary extraction and water-flooding have been exhausted. The process can produce an additional 5-20 percent of the original oil in place. CO_2 injection can be alternated with water injection.

The successful application of CO_2 injection has occurred in the Permian Basin of West Texas and in eastern New Mexico. It is currently being applied to a limited extent in Kansas, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania.

The NETL study (Dilmore, 2010) is one of the most comprehensive analyses of CO_2 enhanced recovery to date. The NETL study is a gate-to-gate analysis beginning with the pipeline delivered CO_2 and ending with crude oil at the sales point. The systems boundary includes facility closure and decommissioning.

The oil recovery technology method involves alternating CO_2 and water injection to recover crude oil. The study estimates that for the current maximum oil recovery case, extraction and transport GHG emissions are 71 kgCO_2/bbl oil (≈12 gCO_2e/MJ), whereas historically they have been 51 kgCO_2/bbl (≈9 gCO_2e/MJ). This is because as crude oil recovery rate increased from a historical 12% to the current best practice of 17%, energy consumption also increased. If the recovery rate were increased to 21%, GHG emissions would rise sharply to 92 kgCO_2e/bbl (≈ 16 gCO_2e/MJ).

There are some differences between the historical CO_2-EOR and best practice CO_2 EOR. In a historical practice, the amount of CO_2 injected has been limited due to the cost of purchased CO_2 for injection. The total cumulative amount injected is 40% of total hydrocarbon pore volume (HCPV) over the flood lifetime. Once injected CO_2 comes out with produced fluid and is separated from the fluid, recompressed and reused. At the end of CO_2 flooding, a slug of water is injected into the formation to recover any residual CO_2 in the formation. This CO_2 is transferred to a nearby field and is used as tertiary EOR solvent. Even after water slug injection for recovering CO_2, about 2000-4000 scf of CO_2 would still remain trapped in the rock formation for each incremental barrel of crude oil produced.

In the best practice scenario, the injected volume of CO_2 increases to 100% of HPCV. Such a high volume injection is economically possible if the crude oil price is high. Similar to the historical case, CO_2 in produced water is recovered and reused but there is no water injection at the end of CO_2 flood.

For the purpose of the analysis, the NETL study identified 1600 potential reservoirs based on three criteria: minimum field size of 50 million barrels, minimum reservoir depth of 300 feet and minimum crude API gravity of 17.5.

Dilmore (2010) used reservoir parameter values that represent the average values reported in the proprietary database developed by ARI, Inc. This database is very comprehensive and contains reservoir characteristics, reservoir fluid property, well count, and cumulative historical production data. The database cover 228 reservoirs in the Permian Basin and also include data for Mid Continent (OK, AR, KS, NE), Rockies (WY, UT, CO), California, Gulf Coast, Williston Basin, East and Central Texas, Illinois, and Appalachian basins. The NETL report itself provides average values for several parameters applicable to the Permian Basin that can be useful for generic modeling of CO_2 enhanced recovery. These average parameter values are shown below in Table 2.13 - Table 2.16.

The injected CO_2 is of anthropogenic origin but the study does not specify the source. Since the system boundary starts with the purchased CO_2, emissions/credits associated with CO_2 production and transport are not included.

Table 2.13. Fluid Parameter Values Used in Modeling of CO_2-EOR Scenarios and Mean and Standard Deviation Values from ARI Database Permian Basin Reservoirs (Dilmore, 2010) [29]

PARAMETER DESCRIPTION	UNITS	PARAMETER VALUE USED IN STUDY	ARI DATABASE MEAN	STANDARD DEVIATION	MEDIAN
Viscosity of Oil	cp	1.76	4.67	24.78	1.76
Viscosity of water	cp	0.72	0.721	0.228	0.72
Oil formation volume factor	(RB/STB)	1.2	1.199	0.156	1.16
Solution gas-oil ratio	scf/STB	805	804.5	1138.9	500
API Gravity of Oil	°API	36	36.29	5.55	36
Water Salinity	ppm	96,000	95,934	62,480	90,000
Gas specific gravity	(Air = 1.0)	0.65	0.650	0.003	0.65
C5+	g/mole	183	*	*	*

[29] * Calculated from °API

Table 2.14. Reservoir Parameter Values Used in Modeling of CO_2-EOR Scenarios and Mean and Standard Deviation Values from ARI Database for Permian Basin Reservoirs (Dilmore, 2010)[30]

PARAMETER DESCRIPTION	UNITS	PARAMETER VALUE USED IN THIS STUDY	ARI DATABASE			
			No. of samples	mean	std. dev.	median
Reservoir temperature	°F	123	228	123.5	35.6	112
Reservoir pressure	psia	2,368	205	2,368.5	1,124.7	2,100
Minimum miscibility pressure	psia	1523	-	b	b	b
Dykstra-Parson Coefficient in the production zone	Dimensionless	0.73	224	0.73	0.151	0.75
Average permeability of the reservoir production zone	md	29	228	28.97	135.5	8
Total vertical depth	Feet to top of reservoir	5,826	224	5,826.4	2,665.7	4,700
Net pay (thickness) of reservoir	Feet	76	228	76.1	72.5	55
Actual porosity of field	Fraction (0-1)	0.11	228	0.11	0.0428	0.105
Swept oil saturation value in all segments	Fraction (0-1)	0.32	228	0.306	0.054	0.30
Initial gas saturation value in all segments	Fraction (0-1)	0	-	a	a	a

[30] a: Not reported in ARI database, default value from CO2 Prophet used; b: Calculated from C5+ (calculated value) and mean reservoir temperature

Table 2.15. Injection Schedule Parameters Used in Defining "Historical" Miscible CO_2-flood EOR in the CO_2 Prophet Screening Mode (Dilmore, 2010) [31]

PARAMETER DESCRIPTION	UNITS	CYCLE[A]			
		1	2	3	4
Water/CO_2 Injection Ratio	HCPV:HCPV	-	1.0	2.0	Inf.
Incremental hydrocarbon pore volumes CO_2 injected	HCPVs of CO_2	0.2	0.1	0.1	0
Injection rate of water, in surface units (SURF BBL/D)	Surface bbl/day	-	562	562	562
Injection rate CO_2, in surface units (MMscf/D)	MMscf CO_2/day	1.24	1.24	1.24	-

Table 2.16. Injection schedule parameters used in defining "best practices" miscible CO_2-flood EOR in the CO_2 Prophet screening model (Dilmore, 2010)

PARAMETER DESCRIPTION	UNITS	CYCLE[A]			
		1	2	3	4
Water/CO_2 Injection Ratio	HCPV:HCPV	-	1.0	2.0	3.0
Incremental hydrocarbon pore volumes CO_2 injected	HCPVs of CO_2	0.25	0.25	0.25	0.25
Injection rate of water, in surface units (SURF BBL/D)	Surface bbl/day	-	562	500	562
Injection rate CO_2, in surface units (MMscf/D)	MMscf CO_2/day	1.24	1.24	1.24	1.24

Credits associated with natural gas and natural gas liquids are accounted for using the displacement method. Nearly all (99%) GHG emissions associated with CO_2-EOR activities occur during the operational phase. The rest are from site evaluation and characterization, construction and closure.

Overall, Dilmore (2010) found that extraction and transport emissions of crude oil produced from CO_2 enhanced recovery are relatively high with 12 gCO_2e/MJ for the best practice case (17% oil recovery). The upstream emissions would increase to 16 gCO_2e/MJ if the oil recovery rate increases to 21%.

[31] A: All injection cycles reported in terms of volume, as opposed to time.

The preferred treatment of CO_2 EOR would be to add an engineering assessment of the energy intensity of CO_2 compression and injection to OPGEE. As a temporary solution, Dilmore (2010) suggests that CO_2 EOR is likely to be at least 3 gCO_2e/MJ more carbon intensive than conventional crude production, and this could be adopted as a correction term.

A future application of CO_2 EOR might couple CO_2 separated from power plant exhaust to oilfield injection. This would result in significantly lower emissions from the produced oil, given the sequestration inherent in CO_2 EOR technologies. In these cases, there are significant differences in results obtained depending on the allocation of emissions and emissions credits between the coupled power plant and oilfield operation (Jaramillo et al. 2009). This can result in two views of the system: a system that produces low carbon electric power and slightly higher GHG intensity oil (as found above by Dilmore 2010), or a system that produces low carbon intensity oil and electric power with lower carbon intensity. Before the adoption of specific treatment of CO_2 EOR in regulatory processes, more attention must be paid to this problem of benefits allocation.

2.6.7. Deep water offshore

Offshore oil production involves the exploration, drilling, and production of oil resources under ocean waters. Exploration and production activities include seismic investigations, exploration drilling, and rig operation.

According to Boland and Unnasch (2013), the primary challenge is the data availability for offshore oil production. Where aggregate data are available, one cannot distinguish energy consumption between offshore exploration and production or between offshore and onshore production due to lack of information. Under the EPA Greenhouse Gas Regulation, offshore operations are required to report data but the industry reports the data by platform without any related production data. The Bureau of Ocean Energy Management (BOEM) also provides production information by well. Beath et al. (2013) suggest that it is possible to link production information by wells to associated platforms by using specific ID numbers. Moreover, it is also possible to obtain more data by communicating with project developers and operators and from information sites such as Rigzone (Unnasch et al, 2009, rigzone.com).

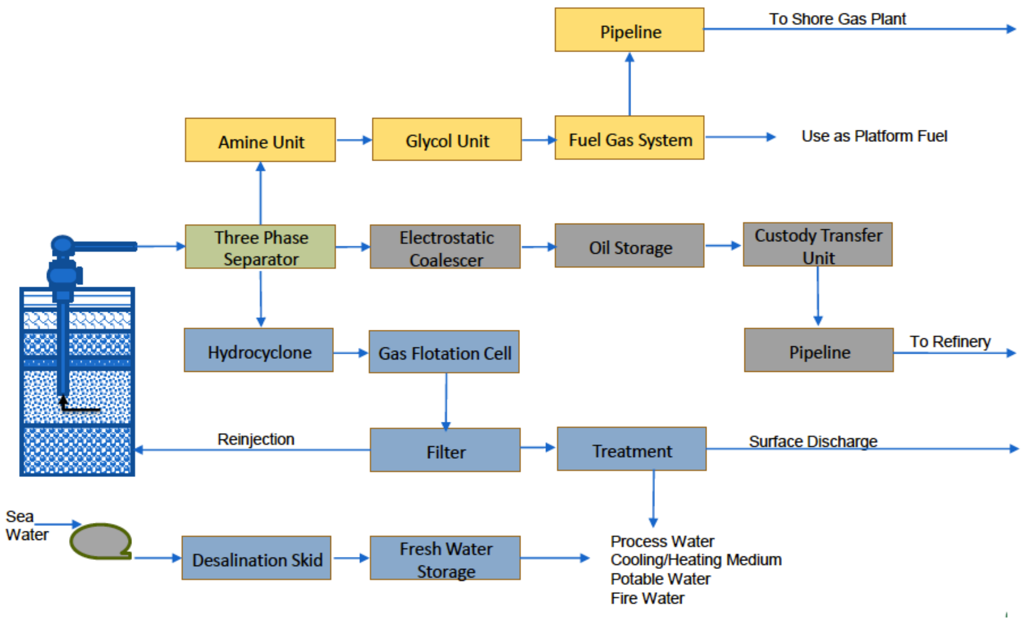

Figure 2.5. An example of offshore platform process flow (Source: Beath et al., 2013)

According to Boland and Unnasch (2013), lack of information on energy inputs and oil throughput has made difficult it to estimate energy consumption. Data that connect production to emissions for offshore operations have generally not been provided by operating companies.

In general, more pumping energy is required for extracting oil from deeper wells. These additional pumping requirements may add another 1gCO_2e/MJ of GHG emissions (Boland and Unnasch, 2013). Offshore emissions vary depending on well pressure, formation depth, age of well, and number of wells/platform. It has been found that higher the production per platform, the lower the emissions (Beath et al., 2013). A key contributor to offshore GHG emissions is venting and flaring emissions. Hence, accurate data on venting and flaring would be essential to estimate the GHG impact of offshore operations. Offshore operations require more infrastructure (steel) than onshore operations. Consideration of embodied (indirect) emissions of infrastructure will make offshore oil production even more carbon intensive (Beath et al., 2013).

In addition to venting and flaring emissions for deep offshore extraction, marine diesel fuel used for exploration and production rigs and associated gas fuel used to drive turbines on production rigs are expected to be the main sources of GHG emissions (Boland and Unnasch, 2013).

A study carried out by ERM (Beath et al., 2013) has found that offshore oil production requires significantly more energy inputs and produces more GHG than conventional oil production because of the requirements for marine vessel and equipment operation in exploration and rig operation.

When extraction emissions per bbl for individual well are estimated and averaged for all wells, GHG emissions for the gulf offshore were found to be 4 times higher than those of the GREET onshore value (*about 100* *kgCO$_2$e/bbl (17.4 gCO$_2$e/MJ) vs. 25 kgCO$_2$e/bbl (4.4 gCO$_2$e/MJ)* (Beath et al., 2013). However, when the bulk average emissions are calculated by dividing the total Gulf offshore emissions by total Gulf offshore production, it turns out to be slightly higher than the GREET onshore estimate (Beath et al., 2013).

More research is needed to properly characterize and accurately estimate emissions from deep water offshore. Based on the limited studies available, it appears that WTW emissions of petroleum fuels derived from deep water offshore would be higher than those of onshore/conventional crude oils.

2.6.8. Summary

Table 2.17 summarizes the average default carbon intensities proposed for coal-to-liquids, gas-to-liquids, kerogen, tight oil and CO_2 EOR respectively. These are considered appropriate values for use in setting average defaults for the FQD, but the emissions of specific facilities may vary from these levels.

Table 2.17. Upstream carbon intensity for unconventional feedstocks and technologies

UNCONVENTIONAL PATHWAY	UPSTREAM EMISSIONS INTENSITY (gCO_2/MJ) OR INTENSITY MODIFIER
GtL	19
CtL	129
Kerogen	52
Tight oil (correction)	+ 1.5
CO_2 EOR (correction)	+ 3

3. Task 3: average greenhouse gas emissions for crudes by trade name

3.1. Summary

For this task, oil fields from ICCT's oil field database and from the oilfield data used by the California ARB for the Low Carbon Fuel Standard have been associated with marketable crude oil names (MCONs) using information through the literature, and a mapping-based analysis of pipelines and terminals. Estimated carbon intensities are presented for the MCONs that the authors believe may be being consumed in Europe. Establishing exactly which MCONs are supplied to Europe would require additional reporting by oil and refined product importers, or else analysis of crude tanker movements. MCON carbon intensities range from below 5 gCO_2e/MJ to over 40 gCO_2e/MJ (Nigerian Adanga crude).

3.2. Introduction

Malins et al. (2014) provided estimated upstream carbon intensities for each category of crude reported as being used in Europe, according to import statistics published by DG Energy. However, many of these categories, such as 'Nigeria medium', do not match traded crude blends, but are instead generic groupings that could consist of several different traded crudes. Option 0 or Option 3 both require default values at the level of traded crude names – or 'Marketable Crude Oil Names', MCONs, to adopt the terminology used under CARB's LCFS. For this task, in order to estimate default (average) carbon intensities for the MCONs consumed in Europe, the fields analyzed in Malins et al. (2014) have been associated (where possible) with specific MCONs. As in Malins et al. (2014), for this report a representative crude methodology has been adopted, where every MCON has been analyzed for which at least one contributing field with adequate data to undertake an OPGEE carbon intensity estimate has been identified.

There is no data available to rigorously determine which precise MCONs are in fact aggregated into the crude categories listed by DG Energy. This report presents the broadest analysis of MCONs that may be feeding EU refineries that was possible given the field data available, including at least one MCON potentially associated with every DG Energy crude category that was assessed by Malins et al. (2014). In addition, CARB data has been used to estimate the carbon intensity of U.S. and Canadian crudes that are not used in European refineries, but which may be being used as feedstocks for diesel imported to Europe from U.S. Gulf Coast refineries.

3.3. Methodology to associate fields with MCONs

There is no single publicly available dataset that details which oil fields are feeding which crudes globally. The MCON assessment is therefore based on combining data from a variety of sources to come to a best expert assessment of which fields are believed to be feeding which MCONs. There is also no dataset that identifies what fraction of each MCON is comprised of each constituent crude. The MCON carbon intensities presented in this chapter are weighted by total production at each constituent field. This is likely to give a good weighting in cases where fields feed a single MCON. However, in cases where oil from a single field may be being supplied through several MCONs, this approach may over-estimate the contribution of the carbon intensity of that field to the carbon intensity of some or all of the MCONs it feeds.

3.3.1. EIA list

The primary source used for the identification of crude names (MCONs) is EIA-856 Appendix A (EIA, 2013), a list of crudes identified by the U.S. Energy Information Administration, which is used for the purpose of reporting U.S. crude imports in the EIA-856 Monthly Foreign Crude Oil Acquisition Report (EIA, 2013). This listing covers 657 MCONs from all regions except the U.S. itself. For U.S. crudes, the MCONs identified for CARB have been adopted. It is considered unlikely that Californian crudes would be refined on the Gulf Coast and shipped to Europe as refined product, and therefore California crudes have not been included.

For each MCON, the EIA list includes national origin and (where available) API gravity and sulfur content of the crude stream.

3.3.2. CIMS data

The Crude Information Management System (CIMS) is a proprietary repository of information on crude and condensate gas fields, owned and updated by Petro Tech – an information provider for crude traders, refiners and economic analysts. The data includes information on over 3500 crude grades including data on reserves, production rates, API gravity, sulfur content as well as updates on new crude grades entering the US market. We have used the CIMS dataset, together with location and field characteristics, to associate MCONs to oil fields included in our analysis, when public data sources where not available. In other instances, we used the proprietary dataset to confirm data found in the public domain.

3.3.3. Energy Redefined pipeline analysis

Using GIS data detailing the locations of oil fields, oil pipelines and crude export terminals; Energy Redefined has identified infrastructure links between several hundred oil fields and terminals globally. Where it is known which MCONs are shipped from which export terminals, it is therefore possible to conclude with moderate confidence that the fields linked by pipelines to those terminals are supplying those MCONs.

3.3.4. Additional research

In addition to these major sources, information has been gathered from a variety of government, industry and internet sources.

3.4. List of default MCON emissions values for crudes refined in the EU

The estimated carbon intensities of the MCONs that are identified as potentially being used in European refineries are shown in Table 3.1 and Figure 3.1. The full list associating fields analyzed by Malins et al. (2014) with individual MCONs is provide in Annex A.

Table 3.1. Carbon intensity of MCONs potentially refined in the EU

COUNTRY	EIA CODE	MCON	°API	SULFUR (WT %)	CARBON INTENSITY (gCO_2/MJ)
Algeria	AG021	Hassi Messaoud	42.8	0.2	10.6
Algeria	AG024	Skikda	44.3	0.1	10.6
Algeria	AG025	Saharan Blend	45.5	0.1	10.3
Algeria	n/a	Arzew			10.6
Angola	AO043	Girassol	31.3		8.5
Angola	AO047	Dalia Blend	23.6	1.48	8.0
Angola	AO050	Greater Plutonio Blend	33.2	0.036	7.6
Azerbaijan	AJ100	Azeri Light	34.8	0.15	5.3
Brazil	BR628	Marlim	20		5.9
Brazil	BR629	Brazil Polvo	19.6	1.14	4.8
Brazil	BR632	Albacora East	19.8	0.52	5.8
Brazil	n/a	Marlim Sul			6.8
Brazil	n/a	Ostra			4.4
Cameroon	CM031	Kole Marine Blend	34.9	0.3	22.7
Cameroon	CM036	Lokele	21.5	0.5	22.3
Cameroon	CM038	Moudi Heavy	21.3		21.4
Cameroon	CM039	Ebome	32.1	0.35	22.4
Congo (Brazzaville)	CF047	Djeno Blend	26.9	0.3	10.6
Denmark	DA292	Dan	30.4	0.3	4.5
Denmark	DA293	Gorm	33.9	0.2	4.7
Denmark	n/a	Siri			5.2
Denmark	n/a	South Arne			5.1
Denmark	n/a	Tyra			5.5
Egypt	EG055	Belayim	27.5	2.2	8.3
Egypt	EG058	Gulf of Suez mix	31.9	1.5	8.9

COUNTRY	EIA CODE	MCON	°API	SULFUR (WT %)	CARBON INTENSITY (gCO_2/MJ)
Ghana	GH044	Bouri	32	0.1	11.1
Iran	IR080	Iranian Light	33.8	1.4	12.1
Iran	IR082	Iranian Heavy	31	1.7	11.2
Iran	IR084	Soroosh (Cyrus)	18.1	3.3	8.8
Iran	IR090	Foroozan (Fereidoon)	31.3	2.5	9.1
Iran	IR093	Bahrgansar/Nowruz (SIRIP Blend)	27.1	2.5	9.2
Iran	n/a	Bangestan Blend			11.5
Iraq	IZ100, IZ200, IZ300	Basrah Light	33.7	2	10.9
Iraq	IZ101, IZ106, IZ201, IZ206, IZ301, IZ306	Kirkuk Blend	34	1.9	10.3
Kazakhstan	KZ211	Tengiz	46.6	0.55	13.9
Kuwait	KU137	Burgan (Wafra)	23.3	3.4	6.4
Kuwait	n/a	Kuwait blend			6.4
Libya	LY120	Bu Attifel	43.6	0	12.2
Libya	LY121	Amna	36.1	0.2	14.1
Libya	LY126	Zueitina	41.3	0.3	12.2
Libya	LY130	Sarir	38.3	0.2	14.1
Mexico	MX281	Maya	22	3.3	6.5
Netherlands	NL100	Alba	19.59		11.5
Nigeria	NI141	Forcados	29.7	0.3	13.5
Nigeria	NI142	Escravos	36.2	0.1	21.2
Nigeria	NI143	Brass River	40.9	0.1	53.9
Nigeria	NI144	Qua Iboe	35.8	0.1	18.4
Nigeria	NI145	Bonny Medium	25.2	0.2	13.9
Nigeria	NI164	Amenam Blend	39	0.09	10.2
Nigeria	NI150	Bonny Light	36.7	0.1	17.4
Nigeria	NI155	Adanga	35.1		41.4
Nigeria	NI155	Frade	35.1		5.4
Nigeria	n/a	Knock Adoon			41.4
Nigeria	n/a	Odudu Blend			10.2
Norway	NO158	Ekofisk	43.4	0.2	5.4
Norway	NO161	Statfjord	38.4	0.3	6.0
Norway	NO165	Heidrun	29		5.1
Norway	NO167	Gullfaks	28.6	0.4	5.6
Norway	NO168	Oseberg	32.5	0.2	6.0
Norway	NO169	Norne	33.1	0.19	5.3
Norway	NO170	Troll	28.3	0.31	4.3
Norway	NO171	Draugen	39.6		5.6
Norway	NO172	Sleipner Condensate	62	0.02	4.3
Russia	RS290	Urals	31	2	11.7
Saudi Arabia	SA180, SA280	Arab Light	33.4	1.8	7.1
Saudi Arabia	SA182,	Arab Medium	30.8	2.4	6.6

COUNTRY	EIA CODE	MCON	°API	SULFUR (WT %)	CARBON INTENSITY (gCO_2/MJ)
	SA282, SA382				
Saudi Arabia	SA183	Arab Extra Light	37.8	1.1	6.2
Saudi Arabia	SA283	Berri (Yanbu)	37.8	1.1	5.5
Syria	SY014	Syrian Light	36	0.6	9.4
Syria	SY430	Souedie	24.9	3.8	8.9
Turkmenistan	n/a	Cheleken			16.9
United Kingdom	UK382	Buchan	33.7	0.8	9.1
United Kingdom	UK386	Tern	35	0.7	4.4
United Kingdom	UK390	Fulmar Mix	40	0.3	10.7
United Kingdom	UK395	Ninian Blend	35.6	0.4	29.8
United Kingdom	UK401	Beryl Mix	36.5	0.4	4.5
United Kingdom	UK403	Forties	36.6	0.3	5.0
United Kingdom	UK404	Brent Blend	38	0.4	9.4
United Kingdom	UK405	Flotta	35.7	1.1	13.5
United Kingdom	UK406	Thistle	37	0.3	11.1
United Kingdom	UK420	Foinaven Blend	26.3	0.38	6.1
United Kingdom	UK421	Schiehallion	25.8		5.2
United Kingdom	UK422	Captain	19.1	0.7	5.6
United Kingdom	UK423	Harding Blend	20.7	0.59	6.9
United Kingdom	n/a	Anasuria Blend			7.8
United Kingdom	n/a	Eider			8.0
United Kingdom	n/a	Gryphon Blend			6.1
United Kingdom	n/a	Liverpool Blend			6.8
United Kingdom	n/a	Ross Blend			19.6
United Kingdom	n/a	Triton Blend			3.7
Venezuela	VE220	Boscan	10.1	5.5	10.0
Yemen	YM013	Gannet Blend	30-31	0.6	4.0

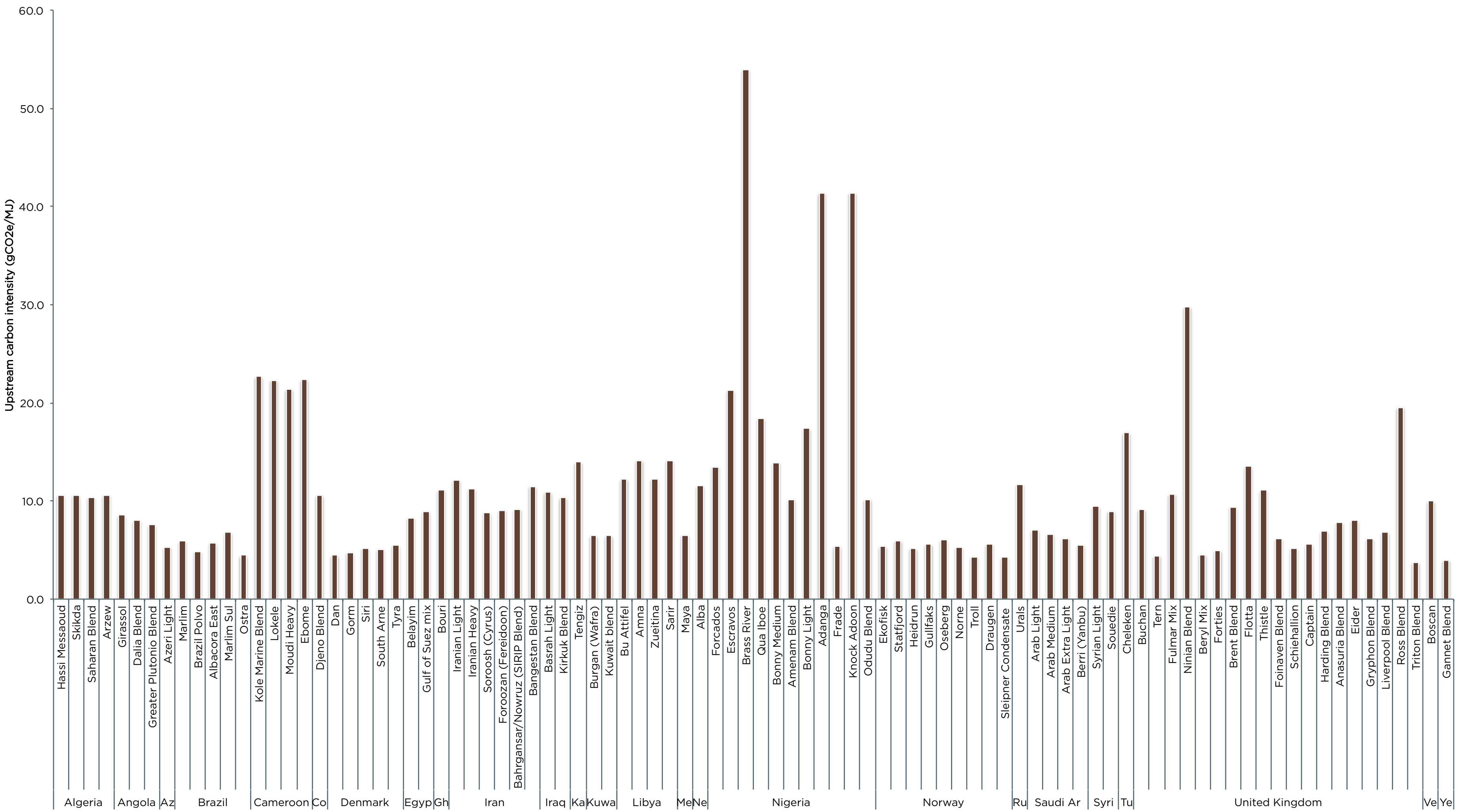

Figure 3.1. Carbon intensity of MCONs associated with crudes refined in Europe

3.5. North American MCONs based on data from CARB

In addition to fuel refined in Europe, the EU imports a significant quantity of refined product, primarily diesel from the U.S. and Russia. There is also the potential for imports of oil from Canada to increase in future if new infrastructure is developed to enable tar sands exports (cf. ICCT/ER, 2010). The Russian Urals blend is included in Table 3.1, but Malins et al. (2014) included no data on North American crudes, as these are not currently substantial contributors to the EU crude pool. In contrast, the California Air Resources Board (ARB) has analyzed several North America MCONs using OPGEE, and has published data on both U.S. and Canadian oil production in the context of the California Average crude CI assessment under LCFS (ARB, 2013). The primary difference between the ARB methodology and the ICCT methodology is that for many MCONs ARB looked to construct notional 'typical' fields, rather than using the representative field approach adopted in Malins et al. (2014). This ARB database is the most comprehensive publically available database on U.S. and Canadian crude production, and therefore this data has been used in this report to assess U.S. and Canadian MCONs. The ARB analysis assumes transport to California refineries. Here, the transport numbers have been adjusted to reflect shipping to Europe before refining. These values therefore overstate the transport element of the upstream emissions for North American refined diesel exports, for which trans-Atlantic shipping is a downstream emission. Alaskan and Californian MCONs are not included as it is expected that these will be refined on the U.S. West Coast, and that refined product from these crudes will not reach the EU market. This analysis has been undertaken in OPGEE 1.1.EU. As discussed above, based on literature review we have adopted a carbon intensity modifier of + 3 gCO_2e/MJ for CO_2 enhanced oil recovery. This contrasts with the ARB treatment, which models CO_2 injection as nitrogen injection. Also, as noted above we have adopted a + 1.5 gCO_2e/MJ modifier for fracked oil, while ARB has not included emissions from fracking itself in its analysis of Bakken and other tight oil.

The conventional-crude-based MCONs from North America are shown in Table 3.2. The Canadian tar sands based MCONs are shown in Table 3.3.

Table 3.2. Carbon intensity of North American conventional crude MCONs

COUNTRY	MCON	UPSTREAM CARBON INTENSITY (gCO_2e/MJ)
US	Niobrara	10.2
US	Four Corners	11.6
US	Bakken	12.4
US	West Texas Intermediate	9.8
US	Covenant	5.2
Canada	Conventional light/medium blends*	9.6
Canada	Conventional heavy blends**	10.9

Analysis based on data from California ARB
**Canada conventional light medium blends value considered representative of Bonny Glen, Cardium, Federated, Halkirk, Koch Alberta, Light Sweet, Mixed Sweet, Peace River Sour, Pembina, Gibson Light Sweet, Joarcam, Kerrobert Sweet, Peace, Rangeland Sweet, Redwater, Tundra Sweet, BC Light, Boundary Lake, Light Sour Blend, Pembina Light Sour, Sour Light Edmonton, Hardisty Light, Medium Gibson Sour, Midale, Mixed Sour Blend, Peace Pipe Sour, Sour High Edmonton, Medium Sour Blend.*
*** Conventional heavy blends considered representative of Bow River North, Bow River South, Fosterton, Lloyd Blend, Lloydminster, Lloyd Kerrobert, Seal Heavy, Smiley-Colville, Western Canadian Blend, Conventional Heavy, Premium Conventional Heavy.*

Table 3.3. Carbon intensity of Canadian tar sands bitumen MCONs

COUNTRY	MCON	UPSTREAM CARBON INTENSITY (gCO_2e/MJ)	TECHNOLOGY ASSUMPTION
Canada	Albian-heavy	22.7	CSS, mined-upgraded
Canada	Cold Lake	21.5	CSS
Canada	Peace River Heavy	23.9	CSS
Canada	Shell Synthetic Light	24.5	Mined-upgraded
Canada	Suncor Synthetic	26.9	SAGD-upgraded, mined-upgraded
Canada	Surmont	21.0	SAGD, mined-upgraded
Canada	Syncrude Synthetic	24.5	Mined-upgraded
Canada	Wabasca	8.7	Primary production
Canada	Western Canadian Select (WCS)*	21.4	Mined-upgraded, SAGD upgraded, SAGD, CHOPS

**California ARB do not have detailed composition data for Western Canadian Select (WCS). They represent it as a mix of 30% Suncor Synthetic, 30% CNRL Primrose Wolf Creek, 30% Cenovus Foster Creek and 10% conventional heavy oil produced with CHOPS (cold heavy oil production with sand).*

3.6. Other feedstocks

The upstream carbon intensity values proposed for coal, natural gas and kerogen as liquid fuel feedstocks are shown in Table 3.4.

Table 3.4. Upstream carbon intensities for unconventional feedstocks

UNCONVENTIONAL PATHWAY	UPSTREAM EMISSIONS INTENSITY (gCO_2e/MJ)
GtL	19
CtL	129
Kerogen	52

4. Task 4: Critical assumptions for the options

4.1. Summary

The specification for this project require that Options 1 and 3 should include 'elevated' default carbon intensity values, i.e. that for reporting purposes default carbon intensities should be set above the expected average or typical values. Setting elevated defaults creates additional incentives to report actual data on carbon intensities, and to take measures to reduce carbon intensities. There are several possible ways to elevate values, including adding a term to all values, multiplying all values by some factor or applying conservative assumptions systematically to the analysis. Multiplying values by a factor provides a stronger signal for higher carbon intensity crudes, which is felt to coincide best with the policy objectives of the FQD. In this report, a 20% elevation is suggested on the upstream carbon intensity values, but the exact degree of elevation is as much a political as a technical decision.

Another important question for a fossil fuel carbon intensity reporting scheme is how often data, methodologies and regulatory values should be updated. It is not appropriate for a regulatory system to react instantly to every change in the science, but it is also not viable to hold values constant indefinitely. In California, the Air Resources Board has proposed a tri-annual process of updates to MCON modeling. For the FQD, it is suggested that a final assessment of regulatory carbon values should be made in 2019, based on 2018 data and an assessment of the best available version of OPGEE for use in the European context. It may also be appropriate to make an interim update to methodologies and values, presumptively in 2016 or 2017.

4.2. Introduction

For each hybrid reporting option considered in this report, there are certain assumptions and decisions on input values that will determine outcomes in the fuel market. This chapter addresses how much to elevate the average GHG default values (for Options 1 and 3) so that an adequate balance is reached between accuracy and administrative burden. Also addressed is how often to update the default values on the basis of achievable reporting, validation and analysis timelines (for all options).

4.3. Elevation

Under any carbon-intensity reporting scheme that includes the option to report default values, it is likely that in some cases the defaults provided will overestimate the actual carbon intensity, and that in other cases defaults may underestimate the carbon intensity. In any such cases, a choice must be made about how to select default values, and hybrid reporting on the upstream carbon intensity of crude oil is no different. The carbon intensity values for individual fields and crude categories presented in Malins et al. (2014) are intended to represent best estimates given the data available in making the calculation. While the use of best estimates is one reasonable choice for defaults, it is not the only one.

Alternative choices could be made for a number of reasons. For one, a ‘best’ or ‘central’ estimate may not be considered properly representative of a range of options subject to uncertainty. For instance, in work on the indirect land use change emissions from biofuels Plevin et al. (2010) find that “the probability distributions for ILUC estimates had a right tail indicating a significant likelihood of large positive values.” In such a case, the statistically expected value for the carbon intensity is larger than the value that would be determined from assessing a central case using best estimates for each individual parameter. Indeed, in the latest indirect land use change analysis for the California LCFS, the values assigned to each feedstock represent an average across a wide set of scenarios (ARB, 2014a). If probability distributions could be associated with OPGEE input values, the same approach could in principle be applied to crude oil modeling.

In some cases, the objective in setting defaults may not be to provide a characterization of the mean or median carbon intensity of a pathway. In European biofuel legislation there are examples of purposefully elevating default carbon intensity values to make them conservative. In the RED and FQD, default carbon intensities for biofuel pathways are based on best estimates with an additional term introduced to elevate the default values, making them conservative. Specifically, an additional 40% is added to the emissions from the processing step of the biofuel supply chain (JRC, 2011). According to industry stakeholders, “the 40% mark-up was designed by the Commission as an incentive to increase production efficiencies” of biofuels (EBB, 2010). In the context of the RED, adding this 40% term creates an additional incentive for biofuel suppliers to undertake an actual-value calculation for their biofuel processing step, and undertaking this calculation may highlight opportunities to improve process efficiencies. In particular, in a subset of cases achieving process efficiencies may be necessary for a biofuel to meet a minimum carbon reduction specification (e.g. a 50% minimum saving). In general, being conservative about the carbon emissions from the processing step makes the assessment of the carbon intensity of the biofuel as a whole conservative, but the degree of overall conservatism applied varies depending on the contribution of processing to the lifecycle emissions. For instance, the pathway for palm oil without methane capture has very high processing emissions and thus is given a relatively low default carbon saving under this system (as compared to the typical saving). In contrast, the pathway for sugarcane ethanol has very modest processing emissions because it is assumed that the process is biomass powered, and therefore the 40% factor affects the overall pathway very little.

An example of a different approach to conservatism was taken under the 2008 carbon and sustainability reporting guidelines for the UK Renewable Transport Fuel Obligation (RTFO). Prior to the implementation by the UK of the Renewable Energy Directive, the RTFO was based on independently developed reporting guidelines, including a lifecycle analysis model and a set of rules for default value reporting (RFA, 2010). Under these rules, there were three levels set for default values, based on the level of data reported. These levels were 'fuel', 'fuel and feedstock', and 'fuel, feedstock and country of origin'. At each level, the default carbon intensity value was set as the highest likely carbon intensity of the fuel batch. 'Likely' in this context meant that the default should be based on the carbon intensity of a fuel pathway that had a specified level of use in the UK market. This meant that is a supplier were able to report both the feedstock and country of origin for a fuel, then they could use a country-level default representing the highest emissions likely for the production of that fuel from that feedstock in that country. However, if the country of origin were not reported, then they would have to use a feedstock level default, which would represent the highest emissions likely for that feedstock globally. The fuel level default (e.g. for ethanol or biodiesel) would represent the highest emissions from any likely feedstock from any country. The idea of this approach was to limit the likelihood that the carbon intensity reported for a fuel batch would be underreported, and to provide encouragement to suppliers to report additional data. For instance, a supplier importing a batch of biodiesel from soy oil from Argentina could have reported a carbon intensity of 48 gCO_2e/MJ. However if the country origin were not reported the default would rise to 78 gCO_2e/MJ (based on an assessment of the carbon intensity of production in Brazil), and finally if the feedstock was not reported the default would be 93 gCO_2e/MJ (based on U.S. oilseed rape biodiesel).

4.3.1. Possible approaches for elevation in Options 1 and 3

In Options 1 and 3, default values will be elevated compared to the best estimates or average values. The level and nature of elevation applied is likely to be a primary determinant of the number of fuel suppliers who could be expected to opt-out of default reporting under either of these schemes. For Option 1, elevated defaults by fuel, there is only one way in which the elevation scheme could be varied, which would be to set a higher elevation on one fuel type than another. The outcome of such a differential would be to create a (relatively minor) driver towards fuel switching between gasoline and diesel. As this type of fuel switching is not an objective of the FQD, there seems to be little reason to take such a step.

For Option 3, however, there are more possibilities. Consider four possible approaches to elevation:

1. Elevation applied as a factor by which the upstream emission value should be increased, e.g. a 20% elevation would imply a factor of 1.2.

2. Elevation applied as a flat increase in all upstream emissions values, e.g. + 3 gCO_2e/MJ.

3. Elevation applied to a single LCA stage, for instance to flaring emissions.

4. Elevation applied by analogy to the principles of the original RTFO (highest likely carbon intensity), with fuel, feedstock and MCON level defaults.

4.3.1.a. Elevation by a factor

Elevation by a factor is the approach considered in Chapter 2, in which the implications for reported carbon intensities of a 20% elevation was considered. Elevation by a single factor is simple. For Option 3, where the elevation would be applied at the MCON level, it would lead to a greater increase (in gCO_2e/MJ) for high carbon intensity MCONs than low carbon intensity ones, providing that much more insensitive for reporting in the high CI cases that may be of most concern.

4.3.1.b. Elevation as a flat increase

For Option 1, elevation by addition is essentially the same as elevation by a factor, as there is no difference between the average upstream carbon intensities at the fuel level. For Option 3, however, where elevation would be applied at the MCON level, the difference between additive elevation and multiplicative elevation is that in the former case, the value benefit from actual reporting will generally be similar across all MCONs, rather than being greater for high carbon intensity crudes. This would be more effective in driving opt-out reporting for lower CI crudes.

4.3.1.c. Elevation on a single LCA stage

This option would be analogous to the elevation methodology used in biofuel reporting under the RED/FQD. Under the biofuel regulation, the elevation has been applied only to the part of the lifecycle that the regulated party is likely most able to influence – the processing stage of biofuel production. For upstream crude carbon intensity reporting, this logic does not suggest a stage to target – in general, all of the major stages occur at the extraction site, which is typically controlled by a different company. An alternate reason for elevating a specific lifecycle stage would be if that stage was considered most uncertain, or if it was felt that the largest opportunities for savings existed at that stage. For instance, if the carbon emissions from flaring were elevated by 40%, this would put additional pressure on suppliers sourcing from countries with high flare rates to report. As flaring is (relatively speaking) generally an easier emissions source to reduce than process emissions, this could result in a driver for actual value assessment especially for those fields where the largest improvements were possible.

On the other side, based on the draft implementing measure for Article 7a of the FQD there will already be a framework to credit upstream emissions reductions through flaring, in which case an additional focus through value elevation might not be necessary. Elevation targeted at a given lifecycle stage could also be perceived as a trade distortion discriminating against some specific region(s) – for instance, as EU oil production tends to have relatively low flaring, elevating flaring only could be perceived as an indirect barrier to trade.

4.3.1.d. Elevation on the basis of 'highest likely carbon intensity'

This possibility, based on the system outlined above from the old UK RTFO, would create a hierarchy of elevated defaults. This would mean that it spanned a middle ground between Option 1 and Option 3. Under this system, the default value for each fuel would be based on the high end of the carbon intensities of individual MCONs. For this to be relevant, there would have to be an option for fuel suppliers to report 'unknown' designation on their fuels – for instance, reporting a batch of diesel derived from unknown MCON(s). The fuel level default could represent, for instance, the estimated 90^{th} percentile of carbon intensity for the fuel supply as a whole. Individual MCONs would then be assigned their best-estimate carbon intensities. Such a system would provide a soft incentive to suppliers to report the MCON origin of their fuels.

It is certainly arguable that in a real world implementation of Option 3 carbon reporting under the FQD there may be a need to allow reporting of fuels from 'unknown' origins, especially in the case of imported refined product where origin data may be more difficult. However, introducing such an 'unknown' option could undermine the driver to introduce data tracking through the chain of custody, and indeed an incentive to suppliers of high carbon intensity oils not to report origins. Setting the reportable carbon intensity for unknown fuel to the highest likely value for fuels of known origin could be a useful alternative to setting regulatory penalties for non-reporting.

4.3.2. Setting the level of elevation for the FQD

Above, four alternative elevation approaches are considered. Henceforth, this report will focus on the first of them, the use of a set factor for elevation, applied to the whole upstream emissions. Many of the considerations discussed below would apply analogously to the choice of the either additive elevation or elevation of a single lifecycle step.

In Chapter 1, a 20% elevation factor was used. The choice of 20% is considered appropriate for the following reasons. For one, it is broadly consistent with the elevation applied for biofuel pathways under the RED/FQD lifecycle analysis methodology. In that methodology, a 40% elevation is applied to one element of the fuel lifecycle, the processing stage. While it varies by pathway, processing emissions tend to be of the order of half of the full pathway emissions, and therefore we consider a 20% elevation of the whole upstream oil carbon intensity value to be inline with a 40% elevation on the processing element of the upstream biofuel carbon intensity value. Secondly, a 20% elevation strikes a reasonable balance between creating an incentive for actual reporting without excessively skewing the carbon intensity values reportable under the FQD. A 20% elevation would add 2 gCO_2e/MJ to a typical upstream value. At this level of elevation, it was hypothesized (based loosely on assumptions from the ICF study) that about 40% of fuel could be reported by actual value under Option 2, rising to 60% under Option 3, but these levels of reporting should be considered illustrative rather than predictive.

While 20% is considered appropriate, there is no well-defined methodology for choosing the best value for an elevation factor, and other choices would be reasonable. The level of elevation applied to default values for reporting in option 1 and 3 will have several distinct implications for the implementation and impact of the regulation, which should be weighed up when setting a regulatory elevation value:

- The higher the level of elevation, the more incentive to suppliers to report actual values. This will increase the accuracy possible in future assessment of the carbon intensity of the EU fuel pool, but will also increase the potential burden of reporting on suppliers.
- Increasing the default CI will tend to increase the average reported CI of the EU fuel pool. This would increase the stringency of the policy, by increasing the level of emissions savings required from low carbon fuels/fuel switching/UERs. This would likely be partly but not entirely offset by increased reporting.
- Increasing the default CI would therefore increase administrative and compliance costs, but also increase environmental benefits.
- Increasing levels of actual reporting would tend to increase accuracy possible in assessment of the carbon intensity of the EU fuel pool, but would simultaneously result in a delta between the *reportable* average EU fossil fuel CI under FQD and the best estimate value for it.

It is anticipated that increasing the level of elevation would increase levels of opt-out reporting, and hence compliance costs, but as shown in Table 1.18 these costs are not large. The change in cost between no opt-out reporting (Option 0) and 60% opt-out reporting is only estimated as 3 million euros at maximum. Compared to the overall cost of FQD compliance, this is a relatively negligible value, and one would similarly expect that if greater levels of elevation were used to increase the degree of opt-out reporting, the costs would still be only moderate.

The picture for compliance costs could potentially be more significant. In the assessment of costs from Options 1 and 2 presented for Task 1, it is estimated that the effect of a 20% elevation of fuel-level defaults on the compliance cost of FQD would be up to 40 million euros, for the case in which iLUC factors are not adopted. This cost comes because increasing the level of elevation of defaults increases the average carbon intensity that will be reported for the EU fuel market, and therefore proportionately increases the emissions savings that need to be delivered through alternative fuels and upstream emissions reductions. The cost implications of increased program stringency increase non-linearly as compliance options move up the cost curve.

4.3.2.a. iLUC factors and elevation

In the case that iLUC factors are introduced, many compliance options are removed or increased in effective cost, making compliance with the 6% target more expensive overall. In that case, the cost implications of a higher level of elevation are more abrupt (a cost difference of up to 400 million euros between Option 1 and Option 2) and therefore it may be appropriate to consider a more moderate level of elevation were Option 1 or 3 to be implemented alongside iLUC factors.

4.3.2.b. Suggested level of elevation

In Option 3, the 20% elevation assess in Task 1 would mean about 1 gCO_2e/MJ on the upstream carbon intensity of a standard conventional crude with low flaring, and 4 or 5 gCO_2e/MJ on the upstream emissions of a tar sands crude or one of the other high carbon intensity crudes. For Option 1, it would mean a ~ 2 gCO_2e/MJ increase in the reportable upstream emissions of crude feedstock for gasoline and diesel fuels. This level seems appropriate, both high enough to encourage reporting and low enough that the elevation would not unduly dominate the reportable carbon intensity of the industry (a difference in average reportable carbon intensity of about 0.3 gCO_2e/MJ is expected from a 20% elevation in Option 1). In the end though, applying a certain elevation is a political decision, and should be informed by the extent to which the European Institutions feel it is warranted to push the oil industry into actual value reporting for the upstream oil industry.

If iLUC factors were introduced, as noted above a higher elevation would be proportionately more costly – in that case, an elevation by 10% would therefore be suggested, but again the final decision must be a policy decision.

4.4. Updates to default values

Another important decision if implementing either default based reporting or a hybrid reporting methodology area is setting the regularity of update of default values. Such updates could reflect either new and changing data or improvements in modeling tools, and hence both are considered in this section.

From the point of view of businesses planning for compliance scenarios, static or infrequently changing defaults defaults provide more certainty for planning compliance strategies, both in terms of choosing crude oils to purchase and in terms of identifying the required level of carbon savings for compliance. However, if updated information demonstrates that the carbon intensity of some MCONs has changed over time, or that there were weaknesses or errors in earlier analysis, then leaving defaults may result in providing incorrect incentives for obligated party behavior.

This issue has been recognized under California's Low Carbon Fuel Standard, and the ARB has already gone through several iterations of MCON carbon intensity results derived using the OPGEE model, including formal review periods for each new set of proposed regulatory values. Since its release in 2012, there have been 6 versions of OPGEE – a consultation version of OPGEE 1.0 followed by a final version, and three draft versions of OPGEE 1.1 (A, B, C and D).[32] The current regulatory values are based on the final release of OPGEE 1.0, and an update to the regulatory values is anticipated later in 2014. In a workshop on 10th July 2014 where the C release of OPGEE 1.1 was presented, an amendment was proposed to the LCFS so that any regulatory updates to the OPGEE tool take place within a three-year revision cycle:

> *Revisions to the OPGEE model, addition of crudes to Table 8, and updates to all carbon intensity values listed in Table 8 will occur on a three year cycle and be considered through an Executive Officer hearing process. (ARB, 2014b)*

Data updates on the other hand will be considered more regularly, and the baseline and MCON default emissions values will continue to be updated with new information whenever it is available, and revised for regulatory purposes on an annual basis.

In the EU context, given that the default MCON values proposed in this report are based on a limited data set, there is enormous potential for additional data to be identified that could result in updates to the default values. Regulated parties could submit such data as part of annual reporting, could be provided directly to the Commission by oil companies or could be gathered by other stakeholders. To attempt to update regulatory values every time new data came to light would not be viable. However, fixing current values in place through to 2020 would raise a significant risk that some MCON values would not be representative of more up to date knowledge. For suppliers refining those MCONs, this could result in serious distortions to their compliance obligations (under an Option 3 system of MCON defaults). While some MCON estimates could change dramatically, variation in the EU average upstream emissions values would be much more moderate. Nevertheless, improved and changing data, and a changing crude mix, are all likely to drive variation – potentially by several gCO_2e/MJ. For example, revisions following expert and stakeholder consultation led to a reduction by 0.5 gCO_2e/MJ in the estimate average upstream CI of European crude presented by Malins et al. (2014) between the review and final drafts.

On the modeling side, updates are also inevitable between now and 2020 that Europe may need to respond to. These could include new versions released by Stanford, new regulatory versions adopted by the California ARB, and given that OPGEE is an open source model there is also the possibility of other stakeholders proposing new model versions or developing new modules. Clearly, it would not be viable to automatically adopt every new version released, especially as new versions may have been subjected to widely varying levels of review. Setting clear intervals for innovations to upstream modeling to be considered should allow constructive stakeholder and expert input.

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[32] See the Stanford and ARB websites, https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator and http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm

In addition in the EU, the appropriate regularity of update of default values should be informed by the implementation of the FQD chosen by member states. In particular, if Member States choose to implement interim carbon intensity reduction targets between now and 2020 then that would strengthen the case for additional interim updates of default values. Such interim targets are expected to be implemented in Germany at least, starting in 2015. The imposition of interim targets could also affect the level of data that Member States and the Commission will be able to collect from regulated parties. With interim targets *and* a hybrid-reporting scheme, there would be an opportunity to collect substantial data through the regulatory process before 2020. Without interim targets, the driver for regulated parties and/or oil producers to engage would be somewhat weaker.

In the case that updates are made, choosing the year for which data will be collected could also be important. In principle, it would be possible to wait until after 2020 data has been collected from regulated parties and reassess default values for compliance on a retrospective basis. However, while such an approach would maximize the accuracy of the assessment, it would make it impossible for regulated parties to precisely assess their compliance position until after the compliance period had ended. This would introduce uncertainty and substantially increase the likelihood that regulated parties could find themselves unexpectedly out of compliance, and may drive over compliance, which does not seem to be in line with the intent of the regulation. It is therefore suggested that the 2020 default values should be set before the start of the 2020 compliance period, allowing regulated parties to confidently assess their compliance position. This would require values to be calculated (and reviewed as appropriate) in 2019, and hence effectively implies that the final set of default values should be based on data from 2018 or earlier. While in some cases oilfield management may change substantially between 2018 and 2020 (for instance entering secondary production, or implementing significantly different reservoir management practices), in general using data of this vintage should not introduce inaccuracies to the assessment large enough to be considered fundamentally problematic. This data update should be accompanied by an expert assessment of the best available version of OPGEE (or potentially an alternative upstream modeling tool), which should then be adopted for the revised assessment.

If a combination of hybrid reporting in line with Option 3 (i.e. based on MCON defaults) and interim targets were to be implemented in one or more Member States, there would be a strong case for an additional update to default values between the adoption of a hybrid reporting mechanism and the publication of final values in 2019. This would allow regulated parties and other stakeholders to react to the adoption of hybrid reporting by collecting and submitting data, allow additional expert review and feedback on the OPGEE model, and potentially allow pathways currently not included in the engineering model to be added. A revised set of defaults could be expected to be more closely aligned to the final 2019 values, and would therefore reduce uncertainty for regulated parties, as well as giving an improved basis for longer term purchasing decisions. It is suggested that such an update could be undertaken in 2016, with a view to releasing new defaults for the start of the 2017 or 2018 reporting year. The precise dates on any updates should be made at the discretion of the European Commission, with due regard to the final adoption date of any new reporting rules in the Article 7a implementing measure and to feedback from stakeholders.

Irrespective of the policy outcome and the precise update schedule, the Commission could consider the following measures:

- An active program of consultation with the industry and other stakeholders, via a call for evidence and workshops. This could be managed by either the JRC, JEC or by appointed consultants who would consider the submitted evidence and develop a revised dataset for re-analysis.
- A call for evidence conducted either with full transparency of submitted data or with an offer of confidentiality for data submitted in confidence. Imposing transparency on all submitted data may reduce rates of data submission but would boost confidence in the process and allow for independent review of data. Allowing confidential data reporting could boost rates of submission, but would reduce transparency and could foster a risk of inaccurate data being submitted.
- Appointing consultants to undertake additional data research, or negotiating with oil-industry data holders for purchase of additional field data.

4.5. Scope of fuel-level defaults (Options 1 and 2)

In this report, it is assumed that default values in any reporting option will represent (potentially elevated) averages across the full fuel pool. However, ICF (2013) hypothesized a case in which oil supplied by opt-out reporters would be 'removed' from the pool of crudes assessed for fuel-level defaults. Presuming that opt-out reporting would preferentially target lower carbon intensity oils, the fuel-level defaults would then tend to increase over time as they increasingly represented only the higher carbon intensity crudes. This would likely only apply in the case that Member States adopted interim carbon intensity reduction targets, as without interim targets there would be little incentive for opt-out reporting before 2020. If such a system of removing opt-out reporters from the calculation of fuel-level averages were implemented, the increase of default values would tend to create an increasing driver for actual value reporting. Increasing the defaults over time would also tend to increase stringency of the program, as compared to static defaults.

Such a system of evolving fuel-level defaults would certainly have some advantages that could contribute to wards program goals. For the case of Option 2 (fuel-level defaults without elevation) this system would maximize the accuracy of the assessment of the overall carbon intensity of EU crude (as discussed in Task 1, otherwise selective reporting would tend to result in underestimation of overall carbon intensity). It would also create a progressive driver for actual reporting, which could be considered desirable if there is a policy objective to increase reporting rates over time. On the other hand however, evolving defaults would create complication for regulated parties and additional administrative burden for the Commission. If evolving defaults were to be based on data from the previous year, then they could only be confirmed once the new compliance year was already in progress.

Given that it is unclear how many Member States will implement interim targets, the relatively short period to 2020 and the option to use elevation as an alternate driver of increased reporting, this option is not considered necessary for a successful program, and the complications may outweigh the benefits. However, there are no fundamental barriers to implementation, and thus such a measure would be an appropriate subject for additional consultation and consideration.

5. Task 6: methodology for opt-out reporting (actual values)

5.1. Summary

This chapter presents a methodology for the calculation of actual values for MCON carbon intensities under a hybrid-reporting scheme. This includes specifications for the minimum set of oil fields feeding an MCON that should be modeled to provide an actual value, and the minimum amount of data that must be supplied for each field to be modeled. In terms of coverage of the fields feeding an MCON, it is suggested that at least 90% of the oil supplied under that name should be covered by modeled fields. This level of coverage should provide acceptable accuracy, while reducing the burden by allowing suppliers to ignore some smaller fields, and potentially ignore some fields for which data acquisition is difficult or impossible. For each field, it is suggested that the minimum data requirement should be based on the parameters included on the 'User Inputs and Results' sheet of the OPGEE model.

These requirements are more stringent than the data requirements set for assessment of default MCON values by the European Commission. Increased data requirements are warranted for actual value reporting because it is important that regulated parties are not given perverse incentives to provide inaccurate actual values by being selective in the choice of data to report. The reporting requirement is considered reasonable because regulated parties have the opportunity to arrange data-sharing agreements with upstream operators. It should be relatively trivial for an oil field operator to provide the data necessary, and there is no significant extra cost associated with tracking a larger number of variables through the supply chain. In any case where it is not viable for a regulated party to set up a data sharing agreement, that party may simply opt-in for default value reporting.

5.2. Introduction

In this report, we have reviewed several different options for estimating and reporting lifecycle GHG emissions from fossil fuels under Article 7a of the FQD. All of these options reflect some form of 'hybrid' reporting. As previously explained (see Task 1), under a hybrid reporting scheme suppliers have the choice of either reporting based on a set of default values for each MCON, or opting out of default value reporting and reporting actual values assessed through lifecycle analysis. The aim of the current section is to describe in detail the methodology for actual value reporting and upstream emission calculation of crude/feedstock names entering the EU. The proposed methodology for actual value reporting uses the OPGEE model. As described in Task 2 of the current report, OPGEE is an engineering-physics based emissions estimation tool that has previously been used in modeling for the European Commission (see Malins et al., 2014). OPGEE is by far the most sophisticated open-sourced oil production model available in the world, and has already been used as a regulatory model in California, making it eminently suitable for use under the FQD. However, in the case of California the tool is only used for default calculation and not for actual value reporting by suppliers. Notwithstanding, we recommend using the OPGEE, as it is an open source tool that allows suppliers, auditors and policy makers readily available access to determining the lifecycle emissions from crude oils.

The current proposal for actual value reporting relies on the OPGEE framework to determine the main input values necessary to estimate the carbon intensity of a given crude/feedstock name. In practice this means that for each crude/feedstock name a number of key data points will be collected based on the necessary inputs identified in the OPGEE tool. These inputs correspond to over 40 variables identified for the estimation of lifecycle emissions of crude. As well as identifying the relevant variables, we have also specified the maximum age that each data point must have. While several indicators at the field level may not vary significantly over time, others do, and need to be updated with more regularity and stringency. We have proposed that these variables be updated on a yearly or three-year cycle depending on their sensitivity to age. Furthermore, for each MCON, the full list of variables must be included for at least 90% of the fields that currently make up the MCON. This is aimed at reducing the opportunities that suppliers with a financial interest might have to cherry-pick fields/values that may reduce their compliance burden.

Once the data inputs are identified, these must be reported to a relevant regulatory body and/or auditor. The regulatory body and/or auditor will then be charged with using the input values to calculate a carbon intensity estimate with the latest version of the OPGEE tool. Since the OPGEE tool is an open source platform, it is not script protected and can be manipulated with ease by someone with sufficient technical knowledge. Having the carbon intensity calculation done by a regulatory body or auditor reduces the risk that the model engineering has been manipulated in any way that ultimately helps reduce the compliance burden for the affected supplier.

For fossil fuel feedstock pathways that are not explicitly modeled by OPGEE, such as CtL, GtL, oil sands, etc, there are two options that can be used to determine the actual values needed for a carbon intensity value. The first option is to delay reporting of actual values for these feedstocks until the lifecycle engineering modules are available in the OPGEE framework. The second is for the regulation to allow the use of alternative LCA tools that do provide modules for each of these pathways. In this case, the regulatory body and/or auditor must also ensure that the tool complies with ISO 14040 series standards on the preparation, conduct and a critical review of lifecycle assessments and inventories. In Task 2 we have provided recommendations based on literature review on what default values can be used for estimates of carbon intensities for these pathways that will also be embedded in the OPGEE tool for this report.

The methodology presented henceforth, is based on the use of an ICCT-modified version of OPGEE v1.1, to be referred to henceforth as OPGEE v1.1.EU. This version incorporates the latest revisions to the tool by Stanford (OPGEE v1.1 Draft D) as detailed on the CARB crude oil analysis webpage.[33]

5.3. Model specification

The OPGEE model is primarily maintained by Stanford University[34] and has been described in detail in Task 2 of this report, and by Malins et al. (2014). Updates to the OPGEE model are on-going as development is carried on continuously by a house team led by Adam Brandt. However, any major improvements or additions to the tool have been spearheaded by the regulatory requirements of the California Air Resources Board. Each time CARB adopts a new version of the tool, it conducts a reanalysis of all MCON carbon intensity values for the Low Carbon Fuel Standard using the new version. Since March 5th 2013, the OPGEE tool has been updated three times for regulatory use under the LCFS. Each time, revisions have been made to both the tool and its accompanying documentation and made publically available for comment and download on the CARB website. The most recent version available is OPGEE v1.1 Draft D. In a recent public workshop (July 10, 2014) a new three-year revision cycle was proposed for any major updates to OPGEE under the LCFS. Assuming that this cycle is adopted, then every three years an Executive Officer hearing will be held by ARB to adopt revisions to OPGEE, add newly certified crude names, update the CI values for all crudes, include the most recent production data available and revise the 2010 Baseline Crude Average CI, if necessary.

Because the OPGEE model is open sourced, the European Commission is not restricted to using the same version of the model to that used by the Air Resources Board. That said, it is recommended that the European Commission conduct revisions to carbon intensity calculations to take into account the latest industry knowledge and process updates. We propose that this follow the same time frame proposed in California and adopt model updates or revisions on a three year cycle. In particular, updates should be sensitive to the incorporation of additional processes and or pathway modules to the OPGEE tool. As reviewed in task 2 of this report, there are several pathways and production technologies that are not covered by the OPGEE framework in engineering detail, notably treatment of tar sands crudes among others. Even so, default carbon intensity calculations for these alternative pathways have been incorporated into the current version of the OPGEE tool so that an emissions estimate can be performed using the current version of the tool.

[33] http://www.arb.ca.gov/fuels/lcfs/crude-oil/crude-oil.htm, as posted 10 October 2014
[34] For the latest version of the model, please refer to https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator

5.4. Principles of actual value reporting

The data requirements set within this report (see Task 2) for *default* value calculation is relatively modest. As previously described, Malins et al. (2014) identified a set of key parameters for each field that tend to have the most influence over the modeled carbon intensity in OPGEE. These are: field age, reservoir depth, oil production volume, number of producing wells, reservoir pressure, API gravity, gas-oil-ratio and water-oil-ratio. For the current analysis, we have deemed that at least half of these eight key parameters must be available for a given oilfield, for a specific default for it to be included in the baseline calculation of crudes entering the European market. This reflects the predictive accuracy of the OPGEE tool in determining default values for those parameters that are not readily available for a given oil field. For any MCONs for which that amount of data is not available, we suggest that a default based on the EU average should be used. The modest data requirements outlined above are due to the general lack of readily available data in the public domain but also because with only a limited amount of data it is generally possible to deliver a robust carbon assessment with the OPGEE model.

This has been described in detail, in a recent publication by El-Houjeiri, Brandt and Duffy (2013). For the publication, they run OPGEE on a small set of fictional oil fields and explored model sensitivity to selected input parameters. Results show that upstream emissions from petroleum production operations can vary from 3 gCO_2/MJ to over 30 gCO_2/MJ using realistic ranges of input parameters. Notably, their findings show that important variations in upstream emissions only occur through the modification of a small set of parameters: water-oil-ratio, field depth, oil production volume, steam-oil-ratio, heater/treater application in surface processing and flaring rate. That said, the authors note that "care must be taken in interpreting results with limited data inputs: if very limited inputs are available, the results will be similar to the generic OPGEE field". In general, the calculation accuracy will improve as more data are added to the model. Other models, including JEC's Well-to-Wheels, have used similar key parameters including crude oil recovery type (primary, secondary, or tertiary), water-oil-ratio (WOR), gas-oil-ratio (GOR), the reservoir depth, and the API of the crude in their analysis (see ICF 2013).

While it is considered appropriate to include fields with relatively sparse data in the calculation of MCON default values, for actual value estimation by suppliers allowing such a low data-threshold for actual value reporting would create the following issues:

- Cherry-picking. When assessing default MCON carbon intensity values based on public data, there is no reason to expect systematic inaccuracies. However, for regulated parties opting-out of reporting default values there would be a well-defined financial incentive to report the lowest possible carbon intensity for each MCON. If it was acceptable under the regulation to report a minimum of four data points regardless of how much data the regulated party actually held, then it would be economically rational for each supplier to report only the set of data that would allow the lowest carbon intensity to be reported. For example, consider a case where a regulated party held data on field age, field depth, API gravity, water to oil ratio and flare rate, and where the flare rate was well above average for the region. Under a limited data requirement, the regulated party could legitimately withhold the data on flaring rate, and thus significantly underestimate the carbon intensity of oil production at the field. A higher data requirement for actual value reporting would reduce the scope for such cherry-picking of data and hence for systematic underreporting of carbon intensities.

- Failure to develop chain of data custody. A more stringent data requirement would force regulated parties wishing to opt-out to develop data-sharing agreements with upstream oil producers and implement chain of custody arrangements for oil imports to Europe. A limited reporting requirement is unlikely to drive the development of any new data tracking by the industry. However, a more comprehensive requirement would both support data tracking and assist the Commission to progressively develop a more accurate picture of the carbon intensity of EU oil as a whole. This additional data, and the experience of implementing chain of custody, would be extremely valuable in the event that a more comprehensive system of upstream carbon intensity reporting is considered in future.

5.5. Minimum required data inputs for each modeled field

The most important data inputs for OPGEE are those listed on the 'User Inputs and Results' sheet of the OPGEE workbook. For conventional oil production these include the parameters outlined in Table 5.1 and Table 5.2 for bitumen.

Table 5.1. Inputs required for actual value reporting

Category	Parameter	Maximum data age (yrs)
1.1 Production methods	1.1.1 Downhole pump (y/n)	1
	1.1.2 Water reinjection (y/n)	1
	1.1.3 Gas reinjection (y/n)	1
	1.1.4 Water flooding (y/n)	1
	1.1.5 Gas lifting (y/n)	1
	1.1.6 Gas flooding (y/n)	1
	1.1.7 Steam flooding (y/n)	1
1.2 Field properties	1.2.1 Field location (Country)	3
	1.2.2 Field name	3
	1.2.4 Field depth	3
	1.2.5 Oil production volume	1
	1.2.6 Number of producing wells	1
	1.2.7 Number of water injecting wells	1
	1.2.8 Well diameter	3

	1.2.9 Productivity index	3
	1.2.10 Reservoir pressure	1
1.3 Fluid properties	1.3.1 API gravity	3
	1.3.2 Gas composition	3
1.4 Production practices	1.4.1 Gas-to-oil ratio (GOR)	1
	1.4.2 Water-to-oil ratio (WOR)	1
	1.4.3 Water injection ratio	1
	1.4.4 Gas lifting injection ratio	1
	1.4.5 Gas flooding injection ratio	1
	1.4.6 Steam-to-oil ratio (SOR)	1
	1.4.7 Fraction of required electricity generated onsite	1
	1.4.8 Fraction of remaining gas reinjected	1
	1.4.9 Fraction of water produced water reinjected	1
	1.4.10 Fraction of steam generation via cogeneration	1
1.5 Processing practices	1.5.1 Heater/treater	3
	1.5.2 Stabilizer column	3
	1.5.3 Application of AGR unit	3
	1.5.4 Application of gas dehydration unit	3
	1.5.5 Application of demethanizer unit	3
	1.5.6 Flaring-to-oil ratio	1
	1.5.7 Venting-to-oil ratio	1
	1.5.8 Volume fraction of diluent	1
1.6 Land use impacts*	1.6.1 Crude ecosystem carbon richness	3
	1.6.2 Field development intensity	3
1.7 Non-integrated upgrader (y/n)		3
1.8 Crude oil transport	1.8.1 Fraction of oil transported by each mode	3
	1.8.2 Transport distance (one way, by mode)	3
	1.8.3 Ocean tanker size, if applicable	3

**Default values may be used for land use, as this data has a historical character and may not be readily available, and because this is a minor emissions source.*

Table 5.2. Inputs required for bitumen extraction and upgrading

Category	Parameter	Maximum data age (yrs)
2.1 Crude or SCO name		
2.2 Crude bitumen properties	2.2.1 Crude bitumen API Gravity	3
	2.2.2 Crude bitumen specific gravity	3
	2.2.3 Crude bitumen heating value	3
2.3 Synthetic crude oil (SCO) properties	2.3.1 SCO API gravity	3
	2.3.2 SCO specific gravity	3

	2.3.3 SCO heating value	3
2.4 Diluent properties	2.4.1 Diluent API gravity	3
	2.4.2 Diluent specific gravity	3
	2.4.3 Diluent heating value	3
2.5 Oil production rate (choose bitumen output or SCO below)		
2.6 Project pathway choices	2.6.1 Upgrading or blending	
	2.6.1.1 Hydrocarbon upgraded – Produce SCO	
	2.6.1.2 Hydrocarbon not upgraded – Produce bitumen for dilution	
2.6.2 Primary extraction methodology	2.6.2.1 Mining integrated	
	2.6.2.2 Mining non-integrated	
	2.6.2.3 In-situ – Non-thermal production (primary)	
	2.6.2.4 In situ – Steam assisted gravity drainage (SAGD)	
	2.6.2.5 In situ – Cyclic Steam stimulation (CSS)	
2.7 In situ steam oil ratio (SOR)	2.7.1 Steam assisted gravity drainage (SAGD) SOR	
	2.7.2 Cyclic Steam stimulation (CSS) SOR	
2.8 Diluent blending	2.8.1 Volume fraction of dilbit as diluent	
	2.8.2 Volume fraction of dilbit as bitumen	
	2.8.3 Dilbit heating value	
2.9 Fuels imported for extraction (or recorded as net imports)	2.9.1 Diesel fuel	
	2.9.2 Natural gas	
	2.9.3 Electricity	
	2.9.4 Coke	
	2.9.5 Still gas	
	2.9.6 Diluent	
2.10 Fuels imported for upgrading (or recorded as net imports)	2.10.1 Diesel fuel	
	2.10.2 Natural gas	
	2.10.3 Electricity	
	2.10.4 Coke	
	2.10.5 Still gas	
2.11 Associated gas composition		
2.12 Land use impact inputs	2.12.1 Crude ecosystem carbon richness	
	1= Low carbon richness (semi-arid grasslands; 2= Moderate carbon richness (mixed); 3= High carbon richness (forested)	

	2.12.2 Field development intensity
	1= Low intensity development and low oxidation; 2=Moderate intensity development and moderate oxidation; 3=High intensity development and high oxidation

It is proposed that all of these data points should be required (where applicable[35]) for every field modeled by fuel supplier choosing to opt-out for a given MCON. The data required for the front-sheet should be readily available to the operators of fields. A regulated party choosing to opt-out would be likely to need to make data sharing arrangements with its upstream supplier in order to supply this amount of data. In all cases, data should be not more than three years old. Production data (volume of oil produced, WOR, GOR, SOR, production methods, injection ratios, reservoir pressure, number of wells) should be representative of the previous calendar year, i.e. 2019 production data must be used for assessing actual values for any oil imported to the EU in 2020.

As noted above, it is anticipated and intended that opt-out suppliers would need to put in place new data tracking systems and new data sharing arrangements in order to report to this level of detail. It is felt that the burden of data tracking should be largely independent of the quantity of data being tracked. While this would represent a significant increase in terms of data points on any previous regulatory reporting requirement, the amount of data involved would be trivial compared to quantities of data routinely handled by modern businesses. The systems required to associate a single data point with a batch of crude oil through the chain of custody would be substantially the same as the systems required to associate one hundred data points with a batch of crude oil, which would be substantially the same as the systems required to track gigabytes of data. We would therefore expect to see no meaningful cost reduction in the chain of custody associated with reducing the minimum required dataset. Similarly, once a data sharing agreement has been implemented there is no reason to believe that it should be substantially more difficult for the upstream producer to pass on a full set of data than to pass on a single data point.

The only point at which there may be an argument that implementation costs would be sensitive to increased data requirements would be at the audit stage. Certainly, the burden for auditors could scale somewhat with the amount of data required, but the fundamental tasks would be comparable. Specifically, the auditor must confirm that the data has been passed correctly through the chain of custody, and that the data used in the calculation is a correct reflection of the data held by the upstream operator. As noted above, the chain of custody assessment should be largely insensitive to the quantity of data transmitted. As to confirming data with the upstream operator, once arrangements have been made to give auditors access to the necessary documentation, checking additional

[35] Not all data will be applicable to all fields. For instance, 'Fraction of steam generation via cogeneration' would only be relevant for thermally enhanced production.

data should not be unduly arduous – although it is admitted that there could be cases where a lack of cooperation or poor recordkeeping by upstream entities could alter this picture.

Additional notes and proposed requirements on reporting the individual parameters are provided below.

5.5.2. Production methods

These binary parameters are used to input the processes being used at each oil field. They include the system used to lift fluid up the well bore (downhole pump or gas lift), and practices regarding reservoir pressure management and gas/liquid disposal (gas and water reinjection or flooding). For thermally enhanced production, steam flooding should be identified. There is also a parameter to identify offshore fields. Production methods will generally change over the lifetime of a field, as additional effort is required to manage the reservoir. This data should therefore be representative of practices in the previous calendar year and no older. Where practices have changed during the year, for instance if gas lift was implemented from April onwards it may be necessary to model the field twice (once for each production regime) and average the results, weighted by the volume of oil produced before and after the change in practice.

5.5.3. Field properties

These are fundamental data related to the properties of the field and its rate of oil production. Some of these parameters are fixed (such field depth), whereas others will change over time (such as productivity index, reservoir pressure and number of producing wells). The field depth should reflect the depth of the well (i.e. the distance that fluid must be lifted from the bottom of the well to the surface). The productivity index and well diameter may vary by well. In such a case, an average value for all the wells in question should be used. In the case that for some reason different wells at the same field have substantially different characteristics or use different production methods, it may be appropriate to split the field into sub-sections and model them separately, averaging the resulting carbon intensities weighted by the volume of oil produced by each subset of wells. Reasons for such differences between wells should be explained to the auditor, and data for each sub-field should be submitted to the appropriate regulatory body.

Reservoir pressure and number of wells must be consistent with reported production methods in order to give an accurate result, and therefore should also be reported based on the previous calendar year. The field age is included in the 'User Inputs and Results' sheet but need not be specified for actual carbon intensity reporting, as it is only relevant when using a smart default for water oil ratio, whereas for actual value reporting data on water oil ratio would be required.

5.5.4. Fluid properties

API gravity of crude should already be known to any refiner. The composition of the associated gas is important in calculating the energy needed to process gas and the carbon dioxide equivalent emissions associated with leaks and fugitives. Composition of associated gas may change over time, but it is not expected that the carbon intensity would be highly sensitive to these parameters, so data no older than three years would be acceptable.

5.5.5. Production practices

These data should all be reported based on the most recent calendar year. Only one of water flooding and reinjection ratio will ever be required. This is because flooding designates the case where more water is injected than produced, whereas reinjection designates the case where up to 100% of produced water is reinjected. Similarly, only one of gas flooding and reinjecting ratio will ever be required. Data about steam are only relevant to thermally enhanced production.

5.5.6. Processing practices

Processing practices includes toggles for several oil treatment technologies, as well as inputs related to flaring and venting and (where appropriate) diluent utilization. For the various oil treatment units, in the event that for some reason a fraction of the produced oil is processed through a unit and the remainder is not, then the field should be modeled as two fields with the carbon intensity determined as the average of the two, weighted by the fractions processed and unprocessed.

5.5.7. Land use impacts

Land use impacts reflect historical emissions associated with developing the oil field. For offshore fields, low carbon richness and low intensity development should always be selected. Yeh (2010) should be referred to for definitions of low, medium and high carbon richness and low, medium and high intensity development. As this data may be historical in character, it is proposed that it should be acceptable for regulated parties to use default inputs for these parameters (medium carbon richness and intensity for onshore developments, low for offshore).

5.5.8. Non-integrated upgrader

This is only applicable for the case in which heavy or extra heavy oil is upgraded before supply to refineries.

5.5.9. Crude oil transport

This should be a characterization of the typical transit pathway of the oil to the refinery. Where crude oil is transported via multiple modes, this can be specified. If, however, there are two routed to the refinery using the same modes in different proportions (e.g. 1000 miles by train and 500 miles by ship, vs. 500 miles by train and 1000 miles by ship for an alternate route) then these alternate routes must be modeled as individual fields, and the carbon intensities averaged, weighted by the volume of oil shipped by each route.

5.5.10. Additional data required for bitumen modeling

Where bitumen is upgraded for delivery to the refinery, the API gravity of the upgraded synthetic crude oil should be specified. Where bitumen is diluted for supply to the refinery, the API gravity of the diluent should be specified, along with the fraction of diluent in the delivered product. Project pathway choices should be based on data from the last calendar year. Steam to oil ration (where applicable) should be based on data for the last calendar year. Unlike the conventional oil model, it is required to specify which fuels have been imported for extraction.

In some case, synthetic crude oil may be used as a diluent (rather than naphtha/condensate). In this case, rather than modeling the bitumen as diluted in OPGEE, the synthetic crude should be modeled separately from the bitumen (modeled with 0 diluent use) and the carbon intensities should be averaged according to the proportions of each in the synbit mix.

5.6. Field coverage required to report an actual value for an MCON

In addition to defining the amount of data required to undertake an actual value analysis of the carbon intensity of an individual field, it is necessary for the methodology to define what fraction of the fields feeding a given MCON must be analyzed to set an actual value for the MCON as a whole.

As detailed in Malins et al. (2014) and Task 2 of the current report, the process that is proposed for calculating the default carbon intensity of a given MCON is the representative field methodology. This approach allows estimates to be made of MCON-level carbon intensities whichever fields feeding that MCON that have data available. In the most data-limited case, a single field may be taken as representative of an MCON fed by several fields. While this representative fields approach is considered an appropriate compromise between data availability and accuracy, it is understood that in some cases it is likely to result in significant errors in the identification of the average carbon intensity for particular crudes.

For regulated parties undertaking actual calculations of MCON carbon intensities, allowing a representative fields approach to be used would introduce issues analogous to those described above in relation to the number of data inputs required. Allowing MCON carbon intensities to be reported based on single or limited numbers of constituent fields would create a clear incentive to cherry-pick and analyze only the most carbon-efficient fields. It is therefore proposed that in order to report an actual value for an MCON, a regulated party must provide adequate data to assess the carbon intensity of fields supplying at least 90% of the oil feeding that MCON. A threshold of 90% would ensure that in all but the most extreme cases the calculated value was reasonably representative of the MCON, while allowing operators to ignore smaller fields for which data was unobtainable, and reducing the data collection burden for cases where MCONs are fed by large numbers of small fields.

As regards the accuracy of the estimation, consider the following simple example:

Consider an MCON fed by 5 fields with the following production volumes and carbon intensities:

FIELD	VOLUME (bbl/d)	CI (gCO_2e/MJ)
A	1,200	4.8
B	500	4.3
C	50	1.7
D	1,500	3.6
E	300	14.7
Total	**3,550**	**5.0**

Fields A, B and D are the largest, and have relatively similar carbon intensities. Field C is a very small field but has a very low carbon intensity. Field E is a modest field with a high carbon intensity, supplying less than 10% of the oil going into the MCON. Under the representative fields methodology, it would be possible to assess only Field C. This would give a much lower carbon intensity (1.7 gCO_2e/MJ) than the real average value (5.0 gCO_2e/MJ). Under the 90% coverage requirement, an operator would be permitted to ignore Field E and/or Field C. Ignoring Field E would allow a carbon intensity of 4.1 gCO_2e/MJ to be reported. While this underestimates the real average by nearly 20%, it is not completely misleading. If the operator also decided to ignore Field C (perhaps to reduce the administrative burden of data collection) the reportable CI would be increased to 4.2 gCO_2e/MJ. In this case a 90% coverage requirement makes the estimate markedly more accurate than may have resulted from the representative fields methodology. As compared to requiring 100% coverage, it reduced the number of fields that must be assessed be 40%, while reducing accuracy by less than 20%.

Demonstrating that 90% coverage of an MCON has been achieved would require documentation of the total amount of oil marketed under a given name in a year, and data on the amount of oil from each modeled field being supplied to that MCON. This data should be supplied to the auditor and submitted to the implementing authority along with field data used for the carbon intensity calculation.

5.6.1. Handling MCONs of varying composition

The 90% coverage rule could be made more complex in the case of MCONs with a composition that could vary significantly over time. Western Canadian Select (WCS) is one such case, as it is fed by up to 25 existing crude streams (including both conventional and bituminous)[36] in proportions that may vary over time. It is proposed that MCON composition data should be representative of at least a full calendar year. This data should be no more than 3 years old. For example, a regulated party would be able to report an actual value for WCS in 2020 if they were able to supply data from 2018 on the fields feeding the MCON over the year, and adequate field data to cover at least 90% of that volume.

In principle, a regulated party may be able to obtain data describing precisely the set of fields that supplied a given batch of crude sent to a given refinery. For instance, in June 2014 it was reported that Repsol imported a single batch of WCS crude for processing at a refinery in Spain.[37] If the regulated party is able to provide auditable data detailing precisely which fields supplied the batch in question, then the batch may be assigned an actual MCON value based on those specific fields, rather than based on analysis of the fields supplying the MCON over a full calendar year. In that case, the actual value calculated would be eligible for use only for the specific batch, and could not be used by that regulated party for batches supplied at other times during the year unless it could be demonstrated that the exact same fields supplied those other batches in the same proportions.

5.7. Parameters not required for the actual value calculation

In section 5.5, the minimum set of data required to calculate an actual carbon intensity for a given field is specified. However, in some cases a regulated party may have access to additional data that could be used to alter some of the other default values in OPGEE. For instance, it is possible that an upstream producer would be able and willing to specify pump efficiencies. Adding field specific data to the assessment should in general improve the accuracy of the assessment, and therefore it is proposed that regulated parties should be permitted to specify additional input data beyond the required data if they so desire. It is suggested that any such data should be audited and should be required to receive a reasonable assurance statement in order to be reflected in an actual value calculation, even if the implementing authority sets a standard of limited assurance on the required data (see section 5.8).

[36] According to Cenovus, one of the companies managing the WCS MCON, see http://www.cenovus.com/operations/doing-business-with-us/marketing/western-canadian-select-fact-sheet.html

[37] See for example this article from the Guardian newspaper: http://www.theguardian.com/environment/2014/jun/06/first-tar-sands-oil-shipment-arrives-in-europe-amid-protests

5.8. Requirements for data audit and mechanics of reporting

The appropriateness of the suggested methodology for actual value calculation is dependent upon an adequate system being put in place for monitoring, reporting and verification. A system with inadequate data audit would be highly vulnerable to fraud. On the other hand, an excessive requirement for audit would raise costs and may dissuade regulated parties from opting-out. Broadly speaking, there are three options for the verification of reported actual values:

1. All required data is reported to an implementing authority (at either Commission or Member State level), along with supporting evidence. The implementing authority would be empowered to take whatever steps necessary to satisfy itself of the accuracy of the data before approving an actual value.

2. All required data is reported to an implementing authority (at either Commission or Member State level) along with an auditor's assurance opinion confirming the quality of the data. The auditor (either chosen from an approved list or meeting a required qualification) would be empowered to take whatever steps necessary to satisfy itself of the accuracy of the data, to the required assurance level (reasonable or limited).

3. A calculated actual value is reported to an implementing authority (at either Commission or Member State level) along with an auditor's assurance opinion confirming the quality of the calculated value. The auditor (either chosen from an approved list or meeting a required qualification) would be empowered to take whatever steps necessary to satisfy itself of the accuracy of the data and that the calculation had been correctly performed, to the required assurance level (reasonable or limited).

5.8.1. Assessment by the implementing authority vs. assessment by a qualified third party

In Task 1, the estimation of costs of implementation of a hybrid reporting schemes are based on the assumption (carried through from the CE Delft and ICF studies) that audit and verification of carbon intensity values will be undertaken by bodies appointed and paid for by the regulated parties. This is similar to the system in place for biofuel carbon accounting in the UK, Germany and other Member States, for which verified emissions statements are required in reporting but emissions values are generally not reassessed by national authorities. In contrast, in the assessment of carbon intensity values for MCONS in the California LCFS, the California ARB maintains control of all carbon intensity estimation.

The LCFS does not allow hybrid reporting at this time, and the volume of fuel supplied in California is substantially less than the whole European market. The burden on the European Commission (or collective burden on national administrators) of undertaking all carbon calculations based on submitted data need not be larger in total cost terms than the burden if distributed among auditors. However, given the prevailing tendency to reduce civil service staffing levels rather than increase them, and the likely lack of existing expertise in this sort of carbon assessment, it may be challenging for the EU/national administrators to take on a burden that would require a substantial staff commitment. The appointment of verifiers by regulated parties is therefore considered the more promising option in practice.

5.8.2. Standard for monitoring and verification

There is a set of ISO standards that lays out best practices in the assessment, monitoring and verification of the emissions from installations. ISO 14064 Part 1 sets a standard for reporting the carbon emissions of a facility based on an LCA model. ISO 14064 Part 3 sets monitoring and verification standards for this process. ISO 14065 and 14066 respectively define requirements for competence of the body undertaking verification and the personnel undertaking verification. The guidance should be implemented as it pertains to the use of models to undertake a GHG assessment.

5.9. Transparency of reported data

In Task 6, a reporting standard is proposed for actual data reporting. Depending on the way that data reporting and verification is implemented, all of this data may be passed through to a central authority appointed by the Commission, all of it may be reported to national administrators but not then transferred to the Commissions, or else finally the data may remain confidential between a regulated party and its auditor. In the most transparent case, all reported data could in principle be published. As noted elsewhere in this report, and in Malins et al. (2014), one of the major challenges to the modeling and assessment of upstream carbon intensity is the lack of available data. In this context, there would be a clear interest for the European Commission and Member States in taking advantage of opt-out reporting as an opportunity to gather additional oil field data and hence refine the assessment of default emissions values. Data sharing at the Commission level would also allow comparison of reported data between regulated parties as a potential additional tool to corroborate or challenge reported actual values (where reported for the same MCON).

The downside of increased transparency would be that upstream producers may consider this data to be sensitive and therefore the expectation that it would be shared, even only by governmental bodies, may discourage actual value reporting and the development of the chain of information custody. If implementing a hybrid-reporting scheme, it would be appropriate to consult the industry to establish any specific concerns, and in particular whether there would be more sensitivity about some specific OPGEE parameters. It is noted that many parameters that are important for OPGEE are included in national reporting in some countries, and that values are often reported in passing in papers in the industry journals (such as passing reference to water cut or productivity index in papers of the Society of Petroleum Engineers). This suggests that the data required for OPGEE are often not considered commercially sensitive. Note that there may also be concerns about commercial sensitivity regarding data on MCONs supplied to each refinery. This is discussed in section 1.5.6.

Given the value to future analysis of having a database of reported opt-out data, it is suggested that (subject to consideration of specific industry concerns) all OPGEE input data for an actual value calculation should indeed be reported to Member States and thence to the Commission. As opt-out reporting would be voluntary in any hybrid scheme, regulated parties and upstream suppliers would be able to weigh any concerns about data sensitivity against the potential value from reporting reduced emissions. While this field data would also be of some interest to the public, and have value in supporting additional independent study of oil extraction emissions, it is likely that concerns regarding data sensitivity would be much amplified by public disclosure. It is therefore suggested that a presumption might be made against public disclosure, again subject to further consideration by the Commission and Member State administrators.

For oil extraction technologies not currently modeled fully be OPGEE, it is suggested (Task 6) that an option should be made available to undertake a full emissions assessment to determine an actual emissions value for opt out

5.10. System boundaries

In general, the physical boundaries of an oil production facility should match reasonably closely the system boundaries of a field analyzed in the OPGEE model. OPGEE by design covers the full extraction process, including treatment facilities for produced liquids and gas. However, in some cases some infrastructure may be effectively shared between more than one field. For instance, there are cases in the North Sea where water from one field is injected into a well on a different reservoir. There could be cases in which gas from one field is sent for processing at a central facility processing gas from several surrounding fields, and so forth.

We are not aware of any comprehensive existing guidance detailing how to address these cases. The following principles are therefore proposed for use in determining whether a given process unit should be included in the system boundary of a field when modeled in OPGEE.

5.10.1. Handling of produced gas and water

Produced fluids (other than the oil itself) could be exported from one field to another and handled in one of three ways:

- Disposed of;
- Used for reservoir management or otherwise to support oil extraction;

- Otherwise used productively.

In the case of disposal, the emissions related to disposal should be assigned to the field from which the fluid was produced. Hence, if water from one field was transported to a second for treatment and disposal, the emissions related to treatment and disposal should be attributed to the first field. In terms of the OPGEE system boundary, this means that the system boundary is expanded beyond the physical boundary of the first field. In OPGEE, this could for example manifest as including water treatment in modeling a field that has no local water treatment facility, but that exports water for treatment elsewhere.

In the case of use for reservoir management or oil extraction (such as gas injection for pressure support, or gas lift) the emissions should be attributed to the field where the fluid is injected. That means that the emissions related to gas compression and injection should be attributed to the field where injection actually occurs. In OPGEE, this may require modeling a rate of gas injection rate in excess of what could be supported by gas produced at the field, i.e. modeling gas imports.

In cases where material (e.g. gas) would be exported to a second oilfield for use in energy generation, this should be treated as export with credit at the first field, and as imported gas at the second field.

In cases where these rules do not provide a clear answer to the way emissions should be attributed, the producer and its verifier should have regard to ISO guidelines on LCA, and explicitly report the proposed treatment to the national administrator in the country where the actual value is being reported. In such cases, the national administrator should have the prerogative to request an alternate treatment if felt appropriate.

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Annex A MCONs by field

REGION	COUNTRY	FIELD NAME	API GRAVITY	FLARING EMISSIONS (gCO_2e/MJ))	FIELD CI (gCO_2e/MJ)	MCON	MCON CI (gCO_2e/MJ))
Africa	Algeria	Hassi Messaoud	46	4.9	**10.6**	Arzew	**10.6**
						Hassi Messaoud	**10.6**
						Saharan Blend	**10.3**
						Skikda	**10.6**
Africa	Algeria	Ourhoud	40	7.2	**10.0**	Saharan Blend	**10.3**
Africa	Angola	Dalia FPSO	23	5.5	**8.0**	Dalia Blend	**8.0**
Africa	Angola	Girassol FPSO	30	5.9	**8.5**	Girassol	**8.5**
Africa	Angola	Greater Plutonia FPSO	33	5.8	**7.6**	Greater Plutonio Blend	**7.6**
Africa	Cameroon	Ebome (KF)	34	19.9	**22.4**	Ebome	**22.4**
Africa	Cameroon	Kole	31	19.6	**22.7**	Kole Marine Blend	**22.7**
Africa	Cameroon	Mokoko NE plus Abana	29	19.5	**22.3**	Lokele	**22.3**
Africa	Cameroon	Moudi D.	21	18.7	**21.4**	Moudi Heavy	**21.4**
Africa	Congo	Kitina	38	8.9	**10.9**	Djeno Blend	**10.6**
Africa	Congo	Loango	27	8.2	**10.7**	Djeno Blend	**10.6**
Africa	Congo	M'Boundi	40	8.9	**10.6**	Djeno Blend	**10.6**
Africa	Congo	Zatchi	27	8.1	**10.3**	Djeno Blend	**10.6**
Africa	Egypt	Ashrafi	39	6.7	**8.3**	Belayim	**8.3**
						Gulf of Suez mix	**8.9**
Africa	Egypt	Ras Qattara	28	6.1	**9.2**	Gulf of Suez mix	**8.9**
Africa	Libya	Sarir	38	9.1	**14.1**	Amna	**14.1**
						Sarir	**11.1**
Africa	Libya	Bouri	26	8.4	**11.1**	Bouri	**12.2**
Africa	Libya	Bu Attifel	41	9.2	**12.2**	Bu Attifel	**14.1**
						Zueitina	**12.2**
Africa	Nigeria	Adanga	32	39.4	**41.4**	Adanga	**41.4**
						Knock Adoon	**41.4**
Africa	Nigeria	Afia	26	6.9	**9.0**	Amenam blend	**10.2**
						Odudu Blend	**10.2**

Africa	Nigeria	Edikan	29	9.6	**12.0**	Amenam blend	**10.2**
						Odudu Blend	**10.2**
Africa	Nigeria	Ime	28	4.8	**8.0**	Amenam blend	**10.2**
						Odudu Blend	**10.2**
Africa	Nigeria	Afremo	37	11.1	**14.9**	Bonny Light	**17.4**
Africa	Nigeria	Ahia	38	32.0	**36.2**	Bonny Light	**17.4**
Africa	Nigeria	Akaso	37	10.3	**13.9**	Bonny Light	**17.4**
Africa	Nigeria	Cawthorne Chan	37	11.7	**15.0**	Bonny Light	**17.4**
Africa	Nigeria	Diebu Creek	40	24.7	**28.7**	Bonny Light	**17.4**
Africa	Nigeria	Ekulama	32	12.6	**16.4**	Bonny Light	**17.4**
Africa	Nigeria	Elelenwa	36	11.0	**14.3**	Bonny Light	**17.4**
Africa	Nigeria	Etelebou	31	16.3	**20.3**	Bonny Light	**17.4**
Africa	Nigeria	Idama	33	25.9	**28.4**	Bonny Light	**17.4**
						Qua Iboe	**18.4**
Africa	Nigeria	Inda	45	18.3	**21.5**	Bonny Light	**17.4**
Africa	Nigeria	Jisike	41	31.3	**34.9**	Bonny Light	**17.4**
Africa	Nigeria	Jokka	23	11.9	**15.5**	Bonny Light	**17.4**
Africa	Nigeria	Olo	37	13.1	**17.6**	Bonny Light	**17.4**
Africa	Nigeria	Robertkiri	40	7.1	**10.6**	Bonny Light	**17.4**
Africa	Nigeria	Adibawa	26	8.8	**12.7**	Bonny Medium	**13.9**
Africa	Nigeria	Adibawa NE	25	16.0	**19.7**	Bonny Medium	**13.9**
Africa	Nigeria	Agbada	24	6.6	**9.7**	Bonny Medium	**13.9**
Africa	Nigeria	Egbema	33	26.3	**30.2**	Bonny Medium	**13.9**
Africa	Nigeria	Egbema West	41	27.4	**31.1**	Bonny Medium	**13.9**
Africa	Nigeria	Nembe Creek	31	11.5	**15.4**	Bonny Medium	**13.9**
Africa	Nigeria	Obagi	23	11.8	**14.6**	Bonny Medium	**13.9**
Africa	Nigeria	Obigbo North	23	9.2	**11.9**	Bonny Medium	**13.9**
Africa	Nigeria	Otamini	21	13.4	**17.4**	Bonny Medium	**13.9**
Africa	Nigeria	Agbara	38	53.6	**57.6**	Brass River	**53.9**
Africa	Nigeria	Ubie	28	17.3	**22.0**	Brass River	**53.9**
Africa	Nigeria	Abiteye	40	34.7	**38.5**	Escravos	**21.2**
Africa	Nigeria	Benin River	42	8.1	**11.2**	Escravos	**21.2**
Africa	Nigeria	Delta	37	23.1	**25.7**	Escravos	**21.2**
Africa	Nigeria	Delta South	38	31.1	**32.5**	Escravos	**21.2**
Africa	Nigeria	Escravos Beach	31	10.4	**14.3**	Escravos	**21.2**
Africa	Nigeria	Kito	31	13.1	**16.6**	Escravos	**21.2**
Africa	Nigeria	Makaraba	28	20.5	**23.7**	Escravos	**21.2**
Africa	Nigeria	Malu	40	30.9	**33.4**	Escravos	**21.2**
Africa	Nigeria	Meji	32	14.5	**16.3**	Escravos	**21.2**
Africa	Nigeria	Meren	32	39.7	**41.5**	Escravos	**21.2**
Africa	Nigeria	Mina	40	49.1	**51.5**	Escravos	**21.2**
Africa	Nigeria	Okan	38	9.7	**11.1**	Escravos	**21.2**
Africa	Nigeria	Otumara	25	8.0	**11.0**	Escravos	**21.2**
Africa	Nigeria	Saghara	32	9.1	**12.7**	Escravos	**21.2**
Africa	Nigeria	Tapa	40	67.9	**70.7**	Escravos	**21.2**
Africa	Nigeria	W. Isan	40	8.4	**10.7**	Escravos	**21.2**

Africa	Nigeria	Abura	45	17.9	**21.5**	Forcados	**13.5**
Africa	Nigeria	Amukpe	42	49.7	**56.4**	Forcados	**13.5**
Africa	Nigeria	Benisede	22	9.3	**13.0**	Forcados	**13.5**
Africa	Nigeria	Eriemu	21	11.9	**15.4**	Forcados	**13.5**
Africa	Nigeria	Evrweni	26	11.5	**15.5**	Forcados	**13.5**
Africa	Nigeria	Ogini	18	7.4	**10.4**	Forcados	**13.5**
Africa	Nigeria	Olomoro	22	7.2	**10.3**	Forcados	**13.5**
Africa	Nigeria	Opukushi	28	10.6	**14.1**	Forcados	**13.5**
Africa	Nigeria	Oroni	23	6.9	**10.4**	Forcados	**13.5**
Africa	Nigeria	Oweh	26	4.3	**8.0**	Forcados	**13.5**
Africa	Nigeria	Ughelli West	21	14.0	**17.2**	Forcados	**13.5**
Africa	Nigeria	Utonana	20	11.5	**15.0**	Forcados	**13.5**
Africa	Nigeria	Uzere East	29	18.8	**22.0**	Forcados	**13.5**
Africa	Nigeria	Uzere West	25	11.8	**15.6**	Forcados	**13.5**
Africa	Nigeria	Adua	35	14.2	**16.2**	Qua Iboe	**18.4**
Africa	Nigeria	Asabo	35	7.0	**8.8**	Qua Iboe	**18.4**
Africa	Nigeria	Asasa	40	19.2	**23.4**	Qua Iboe	**18.4**
Africa	Nigeria	Ata	26	15.9	**18.3**	Qua Iboe	**18.4**
Africa	Nigeria	Edop	37	16.5	**22.8**	Qua Iboe	**18.4**
Africa	Nigeria	Ekpe	35	14.5	**17.9**	Qua Iboe	**18.4**
Africa	Nigeria	Enang	37	17.2	**19.5**	Qua Iboe	**18.4**
Africa	Nigeria	Etim	37	11.7	**14.5**	Qua Iboe	**18.4**
Africa	Nigeria	Idoho	31	36.0	**40.5**	Qua Iboe	**18.4**
Africa	Nigeria	Inanga	38	14.0	**17.2**	Qua Iboe	**18.4**
Africa	Nigeria	Inim	38	19.3	**21.8**	Qua Iboe	**18.4**
Africa	Nigeria	Isobo	30	31.6	**34.0**	Qua Iboe	**18.4**
Africa	Nigeria	Iyak	38	15.7	**19.5**	Qua Iboe	**18.4**
Africa	Nigeria	Mfem	36	30.8	**33.2**	Qua Iboe	**18.4**
Africa	Nigeria	Ubit	36	11.4	**16.5**	Qua Iboe	**18.4**
Africa	Nigeria	Unam	33	14.8	**18.0**	Qua Iboe	**18.4**
Africa	Nigeria	Usari	23	9.0	**12.4**	Qua Iboe	**18.4**
Africa	Nigeria	Utue	37	13.7	**17.9**	Qua Iboe	**18.4**
Americas	Brazil	Albacora Leste	20	3.3	**5.8**	Albacora East	**5.8**
Americas	Brazil	Polvo	20	3.0	**4.8**	Brazil Polvo	**4.8**
Americas	Brazil	Frade	21	3.2	**5.4**	Frade	**5.4**
Americas	Brazil	Marlim	20	3.0	**5.9**	Marlim	**5.9**
Americas	Brazil	Marlim Sul	26	3.8	**6.8**	Marlim Sul	**6.8**
Americas	Brazil	Ostra	24	2.6	**4.4**	Ostra	**4.4**
Americas	Mexico	Cantarell	22	3.4	**6.5**	Maya	**6.5**
Americas	Venezuela	Boscan	10	3.7	**10.0**	Boscan	**10.0**
Europe	Denmark	Dan	31	3.8	**4.5**	Dan	**4.5**
Europe	Denmark	Kraka	33	3.8	**4.4**	Dan	**4.5**
Europe	Denmark	Cecilie	35	2.9	**5.1**	Gorm	**4.7**
						Siri	**5.2**
Europe	Denmark	Gorm	34	3.8	**4.7**	Gorm	**4.7**
Europe	Denmark	Halfdan	31	4.2	**4.5**	Gorm	**4.7**

Europe	Denmark	Lulita	32	4.7	**5.1**	Gorm	**4.7**
						Tyra	**5.5**
Europe	Denmark	Nini	39	3.0	**4.1**	Gorm	**4.7**
						Siri	**5.2**
Europe	Denmark	Rolf	31	2.7	**4.1**	Gorm	**4.7**
Europe	Denmark	Skjold	29	2.9	**4.6**	Gorm	**4.7**
Europe	Denmark	Svend	36	3.1	**5.6**	Gorm	**4.7**
						Tyra	**5.5**
Europe	Denmark	Valdemar	42	4.9	**5.5**	Gorm	**4.7**
						Tyra	**5.5**
Europe	Denmark	Siri	37	3.1	**7.1**	Siri	**5.2**
						Gorm	**4.7**
Europe	Denmark	Syd Arne	37	3.7	**5.1**	South Arne	**5.1**
Europe	Norway	Asgard	41	13.1	**5.9**	Draugen	**5.6**
Europe	Norway	Njord	35	10.2	**4.4**	Draugen	**5.6**
Europe	Norway	Ekofisk	41	3.5	**5.4**	Ekofisk	**5.4**
Europe	Norway	Eldfisk	41	3.3	**4.5**	Ekofisk	**5.4**
Europe	Norway	Embla	42	6.4	**4.6**	Ekofisk	**5.4**
Europe	Norway	Gyda	48	4.1	**5.6**	Ekofisk	**5.4**
Europe	Norway	Tambar	45	2.7	**3.9**	Ekofisk	**5.4**
Europe	Norway	Tor	38	2.7	**3.6**	Ekofisk	**5.4**
Europe	Norway	Ula	35	3.4	**7.7**	Ekofisk	**5.4**
Europe	Norway	Valhall	42	3.1	**4.4**	Ekofisk	**5.4**
Europe	Norway	Gullfaks	38	3.0	**7.1**	Gullfaks	**5.6**
Europe	Norway	Tordis	68	3.4	**4.8**	Gullfaks	**5.6**
Europe	Norway	Vigdis	68	2.8	**4.0**	Gullfaks	**5.6**
Europe	Norway	Visund	34	5.7	**4.1**	Gullfaks	**5.6**
Europe	Norway	Heidrun	27	3.8	**5.1**	Heidrun	**5.1**
Europe	Norway	Norne	33	2.8	**5.3**	Norne	**5.3**
Europe	Norway	Brage	37	3.2	**7.1**	Oseberg	**6.0**
Europe	Norway	Huldra	30	25.8	**5.6**	Oseberg	**6.0**
Europe	Norway	Oseberg	37	6.0	**5.2**	Oseberg	**6.0**
Europe	Norway	Oseberg Ost	37	2.9	**6.9**	Oseberg	**6.0**
Europe	Norway	Oseberg Sor and Nord	37	3.9	**5.3**	Oseberg	**6.0**
Europe	Norway	Veslefrikk	37	3.3	**9.4**	Oseberg	**6.0**
Europe	Norway	Gungne	34	3.2	**4.2**	Sleipner Condensate	**4.3**
Europe	Norway	Sleipner East	58	7.0	**4.5**	Sleipner Condensate	**4.3**
Europe	Norway	Sleipner West	58	3.4	**4.2**	Sleipner Condensate	**4.3**
Europe	Norway	Snorre	68	3.0	**5.5**	Statfjord	**6.0**
Europe	Norway	Statfjord	38	7.5	**7.2**	Statfjord	**6.0**
Europe	Norway	Sygna	30	2.3	**5.4**	Statfjord	**6.0**
Europe	Norway	Troll	28	19.3	**4.3**	Troll	**4.3**
Europe	United Kingdom	Alba	20	2.9	**11.5**	Alba	**11.5**

Europe	United Kingdom	Guillemot A	37	3.1	**4.4**	Anasuria Blend	**7.8**
Europe	United Kingdom	Teal	37	3.7	**12.0**	Anasuria Blend	**7.8**
Europe	United Kingdom	Ness	37	3.8	**4.5**	Beryl Mix	**4.5**
Europe	United Kingdom	Clair	23	2.4	**3.5**	Brent Blend	**9.4**
Europe	United Kingdom	Columba E	38	2.5	**5.3**	Brent Blend	**9.4**
Europe	United Kingdom	Dunlin	35	4.2	**7.7**	Brent Blend	**9.4**
Europe	United Kingdom	Lyell	36	8.2	**10.2**	Brent Blend	**9.4**
Europe	United Kingdom	Magnus	39	4.4	**12.7**	Brent Blend	**9.4**
Europe	United Kingdom	Merlin	31	3.0	**8.5**	Brent Blend	**9.4**
Europe	United Kingdom	Murchison	36	7.2	**31.9**	Brent Blend	**9.4**
Europe	United Kingdom	Osprey	31	2.9	**9.4**	Brent Blend	**9.4**
Europe	United Kingdom	Pelican	35	3.6	**4.5**	Brent Blend	**9.4**
Europe	United Kingdom	Strathspey	43	9.1	**13.0**	Brent Blend	**9.4**
Europe	United Kingdom	Tern	39	3.8	**9.7**	Brent Blend	**9.4**
Europe	United Kingdom	Thistle	38	9.3	**35.1**	Brent Blend	**9.4**
Europe	United Kingdom	Hannay	32	7.8	**9.1**	Buchan	**9.1**
Europe	United Kingdom	Captain	19	2.5	**5.6**	Captain	**5.6**
Europe	United Kingdom	Eider	34	5.0	**13.3**	Eider	**8.0**
						Brent Blend	**9.4**
Europe	United Kingdom	Otter	37	5.1	**6.7**	Eider	**8.0**
						Brent Blend	**9.4**
Europe	United Kingdom	Blane	42	2.3	**3.5**	Ekofisk	**5.4**
Europe	United Kingdom	Janice	36	6.1	**10.1**	Ekofisk	**5.4**
Europe	United Kingdom	Claymore	30	2.8	**11.9**	Flotta	**13.5**
Europe	United Kingdom	Duart	30	2.4	**3.6**	Flotta	**13.5**
Europe	United Kingdom	Galley	44	6.2	**8.8**	Flotta	**13.5**
Europe	United Kingdom	Highlander	35	2.6	**3.7**	Flotta	**13.5**
Europe	United Kingdom	Petronella	35	5.4	**6.5**	Flotta	**13.5**
Europe	United Kingdom	Piper	37	3.9	**23.4**	Flotta	**13.5**
Europe	United Kingdom	Saltire	42	9.3	**30.9**	Flotta	**13.5**
Europe	United Kingdom	Scapa	33	3.1	**12.5**	Flotta	**13.5**

Europe	United Kingdom	Tartan	39	10.5	**11.8**	Flotta	**13.5**
Europe	United Kingdom	Foinaven	25	3.3	**6.1**	Foinaven Blend	**6.1**
Europe	United Kingdom	Arbroath	38	2.4	**3.3**	Forties	**5.0**
Europe	United Kingdom	Arkwright	40	2.5	**3.7**	Forties	**5.0**
Europe	United Kingdom	Balmoral	39	3.9	**5.8**	Forties	**5.0**
Europe	United Kingdom	Buchan	34	3.7	**4.8**	Forties	**5.0**
Europe	United Kingdom	Buzzard	33	2.3	**3.8**	Forties	**5.0**
Europe	United Kingdom	Carnoustie	39	2.6	**3.8**	Forties	**5.0**
Europe	United Kingdom	Cyrus	36	2.3	**5.0**	Forties	**5.0**
Europe	United Kingdom	Farragon	35	2.3	**3.6**	Forties	**5.0**
Europe	United Kingdom	Forties	37	2.7	**5.9**	Forties	**5.0**
Europe	United Kingdom	Keith	38	6.0	**4.4**	Forties	**5.0**
Europe	United Kingdom	Larch	35	2.6	**4.0**	Forties	**5.0**
Europe	United Kingdom	Machar	40	2.7	**4.1**	Forties	**5.0**
Europe	United Kingdom	Mallard	38	4.4	**7.5**	Forties	**5.0**
Europe	United Kingdom	Nelson	40	3.1	**5.7**	Forties	**5.0**
Europe	United Kingdom	Scott	36	3.8	**15.9**	Forties	**5.0**
Europe	United Kingdom	Stirling	42	3.9	**5.4**	Forties	**5.0**
Europe	United Kingdom	Telford	38	7.1	**6.7**	Forties	**5.0**
Europe	United Kingdom	Thelma	38	6.5	**7.1**	Forties	**5.0**
Europe	United Kingdom	Tiffany	34	4.7	**6.0**	Forties	**5.0**
Europe	United Kingdom	Toni	35	5.9	**7.7**	Forties	**5.0**
Europe	United Kingdom	Auk	38	4.5	**6.0**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**
Europe	United Kingdom	Clyde	38	4.0	**7.5**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**
Europe	United Kingdom	Fulmar	40	11.3	**24.6**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**
Europe	United Kingdom	Leven	39	4.9	**18.5**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**
Europe	United Kingdom	Medwin	39	4.3	**5.5**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**
Europe	United Kingdom	Orion	44	7.9	**9.0**	Fulmar Mix	**10.7**
						Ekofisk	**5.4**

Europe	United Kingdom	Gannet D	43	3.2	**4.2**	Gannet Blend	**4.0**
Europe	United Kingdom	Gannet E	20	1.8	**2.9**	Gannet Blend	**4.0**
Europe	United Kingdom	Gannet F	35	3.0	**4.2**	Gannet Blend	**4.0**
Europe	United Kingdom	Gannet G	39	2.7	**3.9**	Gannet Blend	**4.0**
Europe	United Kingdom	Gryphon	21	4.0	**6.1**	Gryphon Blend	**6.1**
Europe	United Kingdom	Tullich	38	4.7	**6.1**	Gryphon Blend	**6.1**
Europe	United Kingdom	Harding	21	3.3	**6.9**	Harding Blend	**6.9**
Europe	United Kingdom	Douglas	44	2.3	**6.8**	Liverpool Blend	**6.8**
Europe	United Kingdom	Ninian	37	5.3	**29.8**	Ninian Blend	**29.8**
Europe	United Kingdom	Ross	41	4.8	**19.6**	Ross Blend	**19.6**
Europe	United Kingdom	Schiehallion	26	4.1	**5.2**	Schiehallion	**5.2**
Europe	United Kingdom	Hudson	33	2.1	**4.4**	Tern	**4.4**
Europe	United Kingdom	Deveron	38	5.9	**11.1**	Thistle	**11.1**
Europe	United Kingdom	Clapham	30	2.1	**4.0**	Triton Blend	**3.7**
Europe	United Kingdom	Saxon	30	2.6	**3.6**	Triton Blend	**3.7**
FSU	Azerbaijan	Azeri Central	34	3.3	**5.3**	Azeri Light	**5.3**
FSU	Azerbaijan	Azeri East	34	3.3	**5.3**	Azeri Light	**5.3**
FSU	Azerbaijan	Azeri West	34	3.3	**5.4**	Azeri Light	**5.3**
FSU	Azerbaijan	Chirag	35	3.3	**5.3**	Azeri Light	**5.3**
FSU	Azerbaijan	Gunashli	34	3.3	**5.2**	Azeri Light	**5.3**
FSU	Kazakhstan	Tengiz	44	7.1	**13.9**	Tengiz	**13.9**
FSU	Russia	Druzhnoye	33	7.8	**12.8**	Urals	**11.7**
FSU	Russia	Kharyaginskoye	38	7.9	**10.7**	Urals	**11.7**
FSU	Russia	Kogalymskoye	38	7.9	**11.2**	Urals	**11.7**
FSU	Russia	Kravtsovskoye	39	7.9	**9.3**	Urals	**11.7**
FSU	Russia	Nivagalskoye	34	7.8	**12.1**	Urals	**11.7**
FSU	Russia	Nong-Yeganskoye	35	7.8	**11.7**	Urals	**11.7**
FSU	Russia	Pokachevskoye	35	7.9	**11.0**	Urals	**11.7**
FSU	Russia	Povkhovskoye	37	7.9	**14.9**	Urals	**11.7**
FSU	Russia	Samotlor	34	5.2	**11.0**	Urals	**11.7**
FSU	Russia	Tedinskoye	25	7.2	**10.7**	Urals	**11.7**
FSU	Russia	Tevlinsko-Russkinskoye	34	7.8	**11.8**	Urals	**11.7**
FSU	Russia	Uryevskoye	34	7.8	**11.7**	Urals	**11.7**
FSU	Russia	Usinskoye	25	7.1	**10.1**	Urals	**11.7**
FSU	Russia	Vat-Yeganskoye	34	7.8	**12.4**	Urals	**11.7**
FSU	Russia	Vozeiskoye	38	8.0	**11.5**	Urals	**11.7**
FSU	Russia	Pamyatno-Sasovskoye	40	7.9	**13.9**	Urals	**11.7**

FSU	Russia	Unvinskoye	40	8.0	**13.2**	Urals	**11.7**
FSU	Turkmenistan	Dzheitune (Lam)	40	11.5	**16.9**	Cheleken	**16.9**
FSU	Turkmenistan	Dzhygalybeg (Zhdanor)	40	11.5	**17.0**	Cheleken	**16.9**
Middle East	Iran	Nowruz	21	5.8	**9.2**	Bahrgansar/Nowruz (SIRIP Blend)	**9.2**
						Iranian Light	**12.1**
						Foroozan (Fereidoon)	**9.1**
Middle East	Iran	Soroosh	19	5.2	**8.8**	Soroosh (Cyrus)	**8.8**
						Foroozan (Fereidoon)	**9.1**
Middle East	Iran	Aghajari	34	6.5	**16.0**	Iranian Light	**12.1**
Middle East	Iran	Kupal	32	8.3	**12.7**	Iranian Heavy	**11.2**
Middle East	Iran	Ahwaz-Asmari	32	6.4	**11.5**	Bangestan Blend	**11.5**
						Iranian Light	**12.1**
Middle East	Iran	Bibi Hakimeh	30	6.1	**10.6**	Iranian Heavy	**11.2**
Middle East	Iran	Faroozan	29	6.1	**9.3**	Foroozan (Fereidoon)	**9.1**
Middle East	Iraq	Rumaila (South)	34	7.4	**10.9**	Basrah Light	**10.9**
Middle East	Iraq	Kirkuk	33	7.0	**10.3**	Kirkuk Blend	**10.3**
Middle East	Iraq	East Baghdad	23	6.7	**11.1**	Kirkuk Blend	**11.1**
Middle East	Iraq	Zubair	35	7.5	**12.3**	Basrah Light	**12.3**
Middle East	Kuwait	Burgan	31	3.6	**6.4**	Burgan (Wafra)	**6.4**
						Kuwait blend	**6.4**
Middle East	Saudi Arabia	Berri	33	3.0	**5.5**	Arab Extra Light	**6.2**
						Berri (Yanbu)	**5.5**
Middle East	Saudi Arabia	Ghawar	34	2.9	**7.1**	Arab Light	**7.1**
Middle East	Saudi Arabia	Khurais	35	2.6	**6.2**	Arab Light	**7.1**
Middle East	Saudi Arabia	Qatif	34	3.0	**6.6**	Arab Medium	**6.6**
						Arab Light	**7.1**
						Arab Extra Light	**6.2**
Middle East	Syria	Jebisseh	18	5.3	**9.0**	Syrian Light	**9.4**
Middle East	Syria	Khurbet East	25	6.1	**9.0**	Souedie	**8.9**
Middle East	Syria	Yousefieh	24	5.9	**8.8**	Souedie	**8.9**
Middle East	Syria	Omar	42	6.8	**10.2**	Syrian Light	**9.4**

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