OPTIONS FOR REDUCTION OF UPSTREAM EMISSIONS FROM OIL PRODUCTION:

SIGNIFICANCE, IMPLEMENTATION AND CONSEQUENCES

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VERBAND DER ÖLSAATEN-
VERARBEITENDEN INDUSTRIE
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ABBREVIATIONS

AAU	Assigned Amount Units
APG	Associated Petroleum Gas
BCM	Billion Cubic Meters
BCF	Billion Cubic Feet
MCF	Million Cubic Feet
MCM	Million Cubic Meters
CAPEX	Capital Expenditure
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CI	Carbon Intensity
CNG	Compressed Natural Gas
EEA	European Economic Area
EFTA	European Free Trade Association
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Scheme
FQD	Fuels Quality Directive
FSU	Former Soviet Union
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction Partnership
GHG	Greenhouse Gas
GOR	Gas-to-Oil Ratio
GPP	Gas Processing Plant
GTL	Gas-to-Liquid
GWP	Global Warming Potential
ICCT	International Council on Clean Transportation
IEA	International Energy Agency

IOC	International Oil Company
JI	Joint Implementation
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
NGL	Natural Gas Liquids
NNPC	Nigerian National Petroleum Corporation
NOAA	National Oceanic and Atmospheric Administration
NPD	Norwegian Petroleum Directorate
RED	Renewable Energy Directive
RLCFRR	British Columbia Renewable and Low Carbon Fuel Requirements Regulation
SNG	Synthetic Natural Gas
UER	Upstream Emissions Reduction
USD	United States Dollar
VAT	Value Added Tax
VFF	Venting-Flaring-Fugitive
VIIRS	Visible Infrared Imaging Radiometer Suite
WTW	Well-to-Wheel

EXECUTIVE SUMMARY

Introduction

The notion of Upstream Emissions Reduction (UER) was introduced within the recent Council Directive 2015/652/EC on **"laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC of the European Parliament and of the Council relating to the quality of petrol and diesel fuels"** and aims to enforce the implementation of Article 7a of the Fuel Quality Directive (FQD). Currently, there is an **ongoing consultation between the European Commission, Member States experts and key stakeholders** aimed at the development of a common interpretation of the FQD Implementing Measure. The European Commission announced that the output of this consultation will consist of a non-legislative guidance document on approaches to quantify, verify, validate, monitor and report Upstream Emission Reductions (UERs).

The eligibility, monitoring and verification procedures, as well as technical aspects related to projects to be accounted for the acquisition of UER credits are expected to be clarified once the consultation is finalised and the Implementing Measure is transposed within Member States national legislation.

According to Directive 2015/652/EC, "*upstream emissions means all greenhouse gas emissions occurring prior to the raw material entering a refinery or a processing plant where the fuel, as referred to in Annex I, was produced*". Thus, the notion of Upstream Emissions as provided within the Directive includes the following major stages of the fossil fuel lifecycle:

- Exploration and field development,
- Fuel production and recovery,
- Fuel processing,
- Feedstock transportation to the refinery gate.

The **scope of this study** is to:

- provide an understanding of the significance of Upstream Emissions and their reduction,
- explain the preconditions that have to be met if UER are accounted for under the FQD,
- present the practical challenges of implementing UER under the FQD.

Key Findings

UERs compete with Renewable Energies as measures to meet the GHG reduction targets in the FQD. The study shows that UER have the potential to completely fulfill these GHG reduction goals. Other measures such as E-Mobility, LNG, CNG or 1st and 2nd Generation Biofuels would not be needed anymore. Therefore **UER could prevent the use of Renewable Energies** in the transport sector. The substitution effects are dependent on market prices of CO_2 emission reductions. At a low price of 20 US$/t CO_2eq. already half of the FQD target could be met through UER. With prices comparable to those of Renewable Energies the potential CO2 reduction through UER doubles. Another important influence on the emission savings is the timeframe for the accountability of the measure.

The scope and number of emission reduction projects, as well as the magnitude of associated UERs that could presumably be counted towards the FQD target remain unclear. Furthermore, without restrictions related to the eligibility of candidate projects, there is a considerable **risk that the FQD target is achieved with reductions from projects that would have happened anyway**. This would undermine the FQD's initial purpose: achieving additional reductions in the lifecycle carbon intensity of road transport fuels.

In order to establish secure and lasting emission reductions without fraud, an UER project is only eligible to count towards the FQD if it meets a number of ISO standards. Important requirements are concerning the additionally, the quality and the qualifications of certifying bodies, the determination of baseline scenarios and the reporting system.

Other emission reduction options such as biofuels have to meet legally binding sustainability criteria and run through a Life Cycle Assessment. In parallel, UER should be obliged to respect the same standards.

Facts about Upstream Emission Reduction

1. Flaring, venting and fugitive emissions represent the most important source of GHG emissions from oil production operations. Venting and fugitive emissions arise from oil field operations and devices. Sources include well work-overs and clean-ups, compressor start-ups and blowdowns, pipeline maintenance, gas dehydrators, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). Flaring of gas, either as a means of disposal or as a safety measure, is a significant source of air emissions from oil and gas installations.
2. Estimates calculated from satellite images of flares (NOAA data, reported by GGFR) suggest that global gas flaring in 2012 was 144 billion cubic meters (bcm). This represents a massive resource waste and a considerable environmental problem, representing, in terms of emissions, some 400 million tons in CO2 emissions and in terms of quantity of natural gas wasted, one third of the European Union's gas annual consumption. According to a recent study by ICCT , these global flaring quantities are comparable to the annual emissions from 125 medium sized (63 Gigawatt) coal plants in the USA, or, in other words, close to the entire emissions of Brazil, Australia, France or Italy. In some countries with important oil production this is a major contributor to the national greenhouse gas emissions inventory.
3. While flaring emissions can be estimated with some degree of accuracy, venting and fugitive emissions are still very difficult to detect, creating thus an important

uncertainty in the quantification of their contribution to global upstream emissions, as currently, measurement facilities are not widespread. Some studies indicate that GHG emissions related to deliberate venting and leakage of natural gas (fugitive) could represent a share of up to 5% of total global greenhouse gas emissions.

Preconditions and practical challenges that have to be met if UER are accounted for under the FQD

1. **Project eligibility:** The FQD describes in rough lines eligible projects, which are not limited to those reducing venting and flaring emissions. Project eligibility is left to the hands of national legislators who have a large degree of flexibility. Furthermore, ISO 14064-2 limits the scope of eligible projects to those that are additional to the appropriately defined baseline scenario. In any case, the Implementing Measure and the expected non-legislative guidance that will follow should provide clear directions on which projects could be considered as eligible.
2. **Additionality:** Although the FQD does not include a reference on additionality, it is essential to prove - as derived from ISO 14064 - that the emission changes are additional to what would have been expected in a business as usual scenario. Nonetheless, poor additionality criteria would significantly undermine its purpose. In this case, the project baseline, as well as the project boundaries must be clearly defined. It is therefore essential to develop common rules between project proponents and national administrators from Member States on the establishment of these two parameters.
4. **Implementation by Member States:** National administrating bodies must be appointed, which will be responsible for monitoring and receiving emission reductions from regulated parties and for confirming that reports of emissions reductions comply with the requirements of the FQD.
5. **Common rules and criteria among MS:** In order to ensure that the appropriate quality is delivered by all FQD-eligible UER projects, it is necessary for MS to establish appropriate common criteria for measurement and reporting under UER schemes.
6. **Centralized UER registry:** The experience from the EU ETS and the recent transition from a distributed crediting system to a centralized approach with a single EU registry, with standardized monitoring, reporting and verification procedures among Member States shows that under such a system, credit trading is easier, less administration and transaction costs are required and the potential of fraud/double-counting is reduced.
7. **Equal treatment among different emission reduction options:** A requirement for biofuels is a full Life Cycle Assessment; while only a relatively simple CO_2 saving calculation is prescribed for emissions reduction in the fossil fuel sector. Furthermore, in the case of biofuels there is actual deployment, while in the case of fossil fuels emissions savings, these appear to have an accounting character. Thus, despite the fact that the accounting of net emission savings is the correct methodology in the context of climate change policy in the transport sector, it should apply to all emission reduction options equally.

1 INTRODUCTION TO THE PROJECT

The Article 7a(1) of the Fuel Quality Directive (FQD) obliges suppliers to report from 2011 information on, inter alia, the GHG intensity of the fuel they have supplied to authorities designated by the Member States. Furthermore the European Commission is empowered to adopt Implementing Measures concerning the method for calculation and the mechanism to monitor and reduce GHG emissions of fuels used in transport. To this direction the recent Council Directive 2015/652 on **"laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC of the European Parliament and of the Council relating to the quality of petrol and diesel fuels"** was adopted to enforce the implementation of Article 7a of the FQD. The notion of Upstream Emissions Reduction (UER) was introduced within the latter Directive.

Until now, the scope and number of emission reduction projects, as well as the magnitude of associated UERs that could presumably be counted towards the FQD reduction target remains unclear. Without restrictions related to the eligibility of candidate projects, there is a considerable risk that the FQD target is achieved with reductions from projects that would have happened anyway, which would undermine the FQD's initial purpose: achieving real reductions in the lifecycle carbon intensity of road transport fuels.

Currently, there is an ongoing consultation between the European Commission, Member States experts and key stakeholders aimed at the development of a common interpretation of the FQD Implementing Measure (Council Directive 2015/652). The output of this consultation will consist of a non-legislative guidance document on approaches to quantify, verify, validate, monitor and report UERs. The eligibility, monitoring and verification procedures as well as technical aspects related to projects to be accounted for the acquisition of UER credits are expected to be clarified once the consultation is finalised and the Implementing Measure is transposed within Member States national legislation. The Consultant has considered to the extent possible the evolutions in the context of this consultation process during the elaboration of the present Study. Nonetheless, the analysis presented in the following Sections consists of the Consultant's broader understanding, based on a thorough literature review of relevant sources.

The exact implementation of Article 7a of the FQD in various Member States and more specifically the economic cost for achieving the FQD (and RED) targets for emissions reduction in the transport sector shall have a significant impact on the domestic European and national biofuel markets. Therefore, the assessment of UER technologies, their accountability in the context of the FQD, their technical and economic potential is of crucial importance for the prospects of the biofuel sector.

For this purpose the Association of the German Biofuel Industry has commissioned EXERGIA for the elaboration of a study on Upstream Emission Reduction of fossil fuels required in the EU transport sector, as provided in the FQD Implementing Measure Requirements. The present report which is submitted in March 2016 covers three main Tasks:

1. An overview of measures aiming at the reduction of upstream emissions for fossil fuel pathways (Chapter 2);

2. The potential and incentives provided by the FQD and its Implementing Measure for upstream emission reduction (Chapters 3 and 4);

3. Practical aspects relevant to the implementation of an upstream emission reductions (UERs) scheme in the context of FQD Art. 7a and its Implementing Measure (Chapter 5).

2 OVERVIEW OF UPSTREAM EMISSION REDUCTION MEASURES

According to Directive EC/2015/652, "*upstream emissions means all greenhouse gas emissions occurring prior to the raw material entering a refinery or a processing plant where the fuel, as referred to in Annex I, was produced*". Thus, the notion of upstream emissions as provided within the Directive includes the following major stages of the fossil fuel lifecycle:

- Exploration and field development,
- Fuel production and recovery
- Fuel processing
- Feedstock transportation to the refinery gate[1]

The present section focuses on the definition of upstream emissions, as well as on methods and best practices aiming at their reduction. In addition, it provides an overview of upstream emissions reduction incentives in target countries and of key existing projects.

2.1 Overview of Upstream Emitting Activities

Within each major production stage, a number of activities and processes occur. The main stages of the total upstream carbon intensity of fossil fuels can be sub-divided into the following processes:

- **Exploration**, which contains pre-production emissions that occur during primary exploration for petroleum.
- **Drilling and development,** including emissions that occur during development of crude oil production facilities.
- **Production and extraction**, which models the work required to lift fluids from the subsurface and to inject fluids into the subsurface.

[1] It has to be noted that in EXERGIA's recent "Study on actual GHG data for diesel, petrol, kerosene and natural gas", commissioned by DG ENER, the approach on fuel lifecycle stages was slightly different than in the case of Directive EC/2015/652 (which was notified some months later). In the latter study the upstream stage did not include transportation of feedstock, which was rather part of the "midstream" stage. In the present study, the definition given in the Directive will be used.

- **Surface processing**, which models handling of crude, water, and associated gas with a set of common industry technologies.
- **Maintenance**, regarding the venting and fugitive emissions associated with maintenance.
- **Waste disposal,** referring to the emissions about waste disposal.
- **Crude transport,** allowing variation in the transport modes used to transport crude oil from extraction to the refinery stage and the distance travelled.
- **Bitumen extraction and upgrading,** modelling the extraction of crude bitumen separately from the production of conventional crude oil.

Flaring, venting and fugitive emissions represent the most important source of GHG emissions from oil production operations. Venting and fugitive emissions arise from oil field operations and devices. Sources include well work-overs and clean-ups, compressor start-ups and blowdowns, pipeline maintenance, gas dehydrators, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). Flaring of gas, either as a means of disposal or as a safety measure, is a significant source of air emissions from oil and gas installations. Even if continuous flaring ended, occasional burning of small amounts of gas will still be necessary for safety reasons.

Another emitting process is the use of the energy-intensive secondary and tertiary recovery technologies, such as water flooding, gas lifting, gas flooding etc. For the application of these technologies, additional energy is required in order to lift the crude oil from oil well. Other emissions take place due to increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio). At the midstream level, GHG emissions due to transportation can have a significant share in the total GHG emissions assessed, especially when considering crudes imported from distant world areas to the EU refineries.

2.1.1 Significance of venting, flaring and fugitive emissions

Estimates calculated from satellite images of flares (NOAA data, reported by GGFR) suggest that global gas flaring in 2012 was 144 billion cubic meters (bcm). This represents a massive resource waste and a considerable environmental problem, representing, in terms of emissions, some 400 million tons in CO_2 emissions and in terms of quantity of natural gas wasted, one third of the European Union's gas annual consumption[2]. According to a recent study by ICCT[3], these global flaring quantities are comparable to the annual emissions from 125 medium sized (63 gigawatt) coal plants in the USA, or, in other words, close to the entire emissions of Brazil, Australia, France or Italy. In some

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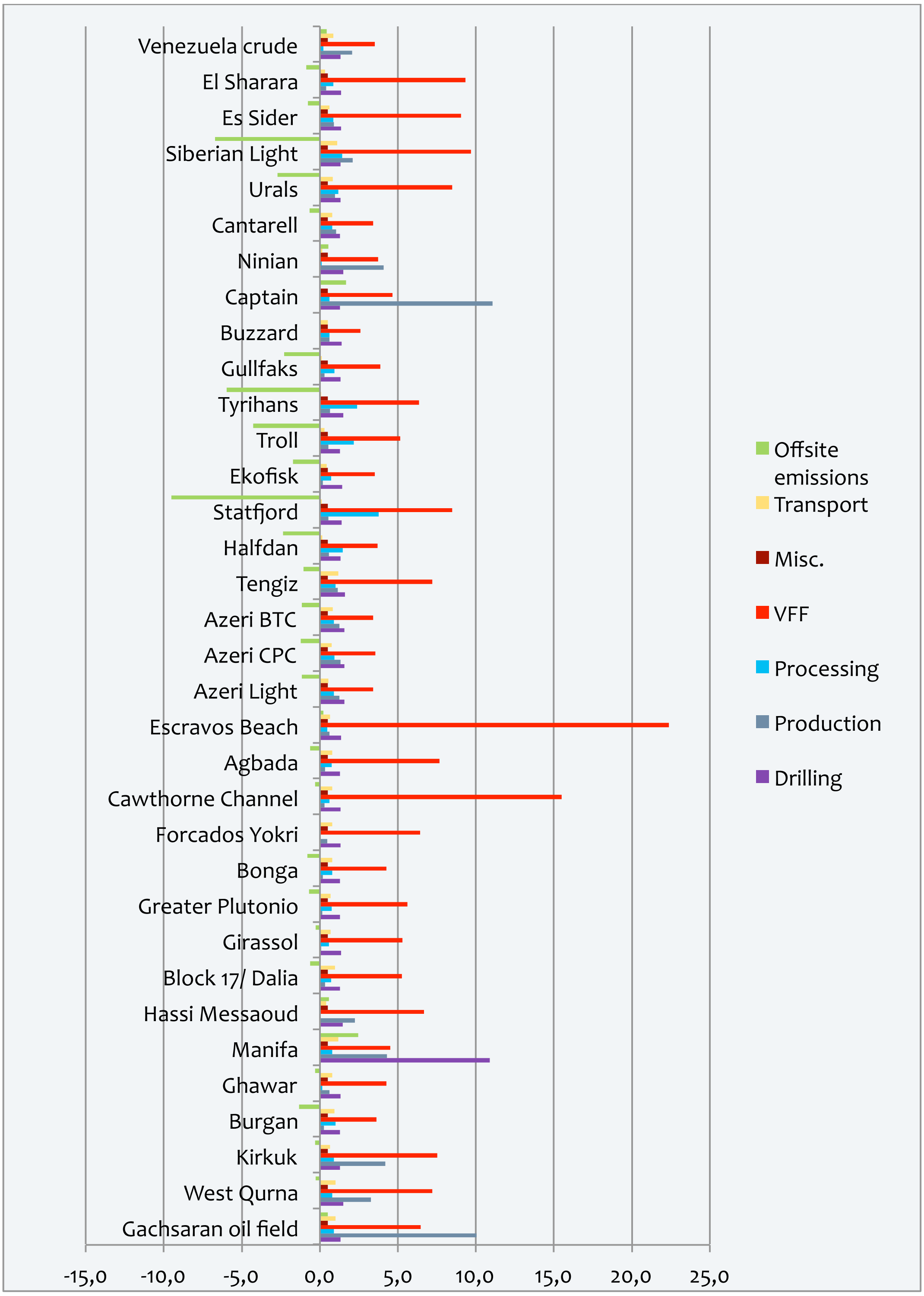
[2] Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan, Carbon Limits, 2013

[3] The reduction of upstream GHG emissions from flaring and venting, Report by the International Council on Clean Transportation to the European Commission Directorate-General for Climate Action, 2014

countries with important oil production this is a major contributor to the national greenhouse gas emissions inventory, such as Nigeria where flaring represents over a third of the country's total CO2 emissions (GGFR, 2012a).

Figure 2-1 Carbon Intensities of major crude oil streams from "well-to-refinery gate" in gr CO2eq/MJ of energy produced



While flaring emissions can be estimated with some degree of accuracy, venting and fugitive emissions are still very difficult to detect, creating thus an important uncertainty in the quantification of their contribution to global upstream emissions, as currently, measurement facilities are not widespread. Some studies indicate that GHG emissions related to deliberate venting and leakage of natural gas (fugitive) could represent a share of up to 5% of total global greenhouse gas emissions[4]. The sources and the nature of these emissions will be discussed in the following Sections.

EXERGIA has recently completed a study on GHG emissions of fossil fuels consumed in the EU transport sector form "well-to-tank", for DG ENER as the Contracting Authority. In the context of this project, carbon intensities for all major crude oil and natural gas streams supplying the EU have been calculated by the use of actual data -where applicable- and engineering models dedicated to the estimation of lifecycle emissions of fuels. Figure 2-1 presents the carbon intensities (referred to in Directive 2015/652 as "GHG Intensities") of major MCONs (Marketable Crude Oil Name) supplying the EU transport sector up to the refinery gate, thus including the upstream and midstream emissions, as defined and estimated within the "Study on actual GHG data for diesel, petrol, kerosene and natural gas". In this Figure the allocation of emissions to each lifecycle stage is clearly illustrated. It is evident that **venting, flaring and fugitive (VFF) contributes substantially to the overall upstream emissions.** Therefore, UER measures will most probably focus on initiatives and technologies aimed at eliminating this type of emissions. The results illustrated in Figure 2-1 are also presented in Table 2-1.

In the Figure 2-1, off-site emissions refer to emissions occurring outside the defined system boundaries of an oil or natural gas field. These emissions could result from materials and services consumed during drilling (e.g. computing energy consumed during seismic data processing), indirect offsite energy use (e.g. embodied energy consumed to manufacture well casing). Offsite emissions also refer to the net balance of electricity imports/exports (and could therefore appear as negative emissions).

Table 2-1 Carbon Intensities of major crude oil streams supplied to the EU from "well-to-refinery gate" in gr CO2eq/MJ of energy produced

	Drilling	Production	Processing	VFF	Misc.	Transport	Offsite emissions	TOTAL
Gachsaran	1.3	10.0	0.9	6.4	0.5	1.0	0.5	**20.7**
West Qurna	1.5	3.3	0.8	7.2	0.5	1.0	-0.3	**14.0**
Kirkuk	1.3	4.2	0.9	7.5	0.5	0.6	-0.3	**14.6**
Burgan	1.3	0.3	1.0	3.6	0.5	0.9	-1.3	**6.3**
Ghawar	1.3	0.6	0.2	4.3	0.5	0.8	-0.3	**7.3**
Manifa	10.9	4.3	0.8	4.5	0.5	1.2	2.4	**24.6**
Hassi Messaoud	1.5	2.2	0.0	6.7	0.5	0.4	0.6	**11.8**

[4] Flaring and Venting of Associated Gas - Current Developments and Impacts of Marginal Oil, ERA - Energy Research Architecture, December 2015

	Drilling	Production	Processing	VFF	Misc.	Transport	Offsite emissions	TOTAL
Block 17/ Dalia	1.3	0.3	0.7	5.3	0.5	1.0	-0.6	**8.4**
Girassol	1.4	0.1	0.6	5.3	0.5	0.7	-0.3	**8.2**
Greater Plutonio	1.3	0.2	0.8	5.6	0.5	0.7	-0.7	**8.3**
Bonga	1.3	0.2	0.8	4.3	0.5	0.8	-0.8	**7.0**
Forcados Yokri	1.3	0.5	0.1	6.4	0.5	0.8	0.0	**9.5**
Cawthorne Channel	1.3	0.3	0.6	15.5	0.5	0.8	-0.3	**18.7**
Agbada	1.3	0.3	0.8	7.6	0.5	0.8	-0.6	**10.7**
Escravos Beach	1.4	0.6	0.5	22.4	0.5	0.6	0.2	**26.2**
Azeri Light	1.6	1.3	0.9	3.4	0.5	0.6	-1.2	**7.0**
Azeri CPC	1.6	1.3	0.9	3.5	0.5	0.8	-1.2	**7.4**
Azeri BTC	1.6	1.3	0.9	3.4	0.5	0.8	-1.2	**7.3**
Tengiz	1.6	1.2	1.0	7.2	0.5	1.2	-1.1	**11.6**
Halfdan	1.3	0.6	1.5	3.7	0.5	0.2	-2.4	**5.3**
Statfjord	1.4	0.6	3.8	8.5	0.5	0.1	-9.5	**5.3**
Ekofisk	1.4	0.2	0.7	3.5	0.5	0.4	-1.7	**5.1**
Troll	1.3	0.5	2.2	5.1	0.5	0.3	-4.3	**5.6**
Tyrihans	1.5	0.6	2.4	6.3	0.5	0.1	-6.0	**5.5**
Gullfaks	1.3	0.3	0.9	3.9	0.5	0.1	-2.3	**4.7**
Buzzard	1.4	0.6	0.6	2.6	0.5	0.5	0.0	**6.2**
Captain	1.3	11.1	0.6	4.6	0.5	0.1	1.7	**19.8**
Ninian	1.5	4.1	0.1	3.7	0.5	0.1	0.5	**10.6**
Cantarell	1.3	1.0	0.8	3.4	0.5	0.8	-0.7	**7.2**
Urals	1.3	1.0	1.2	8.5	0.5	0.8	-2.7	**10.5**
Siberian Light	1.3	2.1	1.4	9.7	0.5	1.1	-6.7	**9.4**
Es Sider	1.3	0.9	0.8	9.0	0.5	0.6	-0.8	**12.5**
El Sharara	1.4	0.4	0.9	9.3	0.5	0.3	-0.9	**11.9**
Venezuela crude	1.3	2.1	0.2	3.5	0.5	0.9	0.4	**8.9**

2.1.2 Flaring emissions

In oil reservoirs, there is always a certain amount of natural gas present. Depending on the pressure in the reservoir, the gas can either be dissolved in the oil, or lay as a cap above the oil. When the oil is extracted, the dissolved gas, also labelled **associated petroleum gas (APG)**, follows. The gas-to-oil (GOR) ratio varies greatly from one oil field to the next, ranging from 1-2 m^3 to thousands of m^3 of gas per ton of oil[5]. When the oil and gas mixture reaches the surface, the gas has to be separated from the oil before the

[5] Associated Petroleum Gas in Russia - Reasons for non-utilization, Fridtjof Nansen Institute, 2010

oil enters the pipelines. Most flaring processes usually take place at stack top with the visible flame, as opposed to incineration, where waste gas is combusted at the furnace. Flaring during well tests, production of associated gas, refining and other processing stages is used in a way of open flame. There are some reasons for that: first, gas may contain corrosive compounds, so it can be quite destructive, secondly, there might be the need to dispose huge amounts of gas in a short time.

Combustion of natural gas is called **flaring**, while releasing it to the atmosphere is known as **venting**. Due to unavailability of local market and transportation systems in production areas, operators usually flare or vent associated gas to avoid additional treatment and processing expenses. Decision of flaring and venting or processing of gas might depend on natural gas prices which could have a major impact on it. For safety reasons, venting is not a common practice.

2.1.3 Venting and Fugitive emissions

Fugitive emissions refer to unintentional methane leakages from oil and gas operations, whereas venting emissions are related to the intentional release of methane to the environment for maintenance or other reasons and they are both a source of greenhouse gas emissions in many countries. Methane emissions occur at all stages of the value chain of natural gas and oil activities, although they concern mainly upstream activities. Methane emissions predominantly occur during gas production and transportation (e.g. from compressors, dehydrators and pumps, pneumatic devices, fugitive leakages, well blow-downs and completions). Production of oil is also a source of methane emissions in many regions (e.g. degassing of fluids, flaring/cold venting and product storage/loading); however oil upstream activities emit much less methane than natural gas upstream operations.

The principal sources of methane emissions in the natural gas sector are attributed to unintentional equipment or pipeline leaks. These fugitive emissions occur as the gas circulates at extremely high pressure through different parts of the infrastructure of natural gas systems and escapes into the atmosphere through tattered connections in the pipelines, worn pump and compressor seals, valves or flanges. Emissions also occur during maintenance and venting activities, as well as through accidents and equipment failures. In the oil sector, methane emissions occur mainly from gas venting from oil wells, oil storage tanks and production equipment. Some studies indicate that methane emissions from natural gas and oil systems account for approximately 18% and 2%, respectively, of global methane emissions. Emissions are expected to grow as natural gas and oil consumption increases, due to aging infrastructure.

These emissions are difficult to quantify with a high degree of accuracy and there is substantial uncertainty in the values available for some of the major oil and gas producing countries (e.g. Russia). In the public domain, available data predominantly originate from North America (i.e. US and Canada) since very few empirical studies are available for other key oil and gas regions. The main reason for uncertainty in the assessment of methane emissions is the fact that measurement programmes are time consuming and very costly to perform, therefore operators tend to rely on the use of simple production-based emission factors which are susceptible to excessive errors.

2.2 Upstream Emission Reduction Technologies

In oil fields where there are important quantities of associated gas, the most common practice utilized until today is flaring, i.e. open air burning of APG. Flaring has severe environmental effects and is economically wasteful. Even in sites with installed burners of high flaring efficiency, there are big amounts of greenhouse gases released to the atmosphere. The output of the flaring process includes mainly carbon dioxide and quantities of methane, which can be quite important depending on the composition of the gas and the flaring efficiency. Methane emission from gas flares is the result of incomplete combustion of the waste gas and thus is related to the destruction efficiency of the flares.

Due to the hazardous consequences of flaring gas, it is not considered as an option for upstream emission reduction, although it is a solution for minimising the emission of methane, which is a much more potent gas than carbon dioxide, in terms of global warming. Therefore flaring will not be discussed as an upstream emission reduction option in the present section, which will rather focus on alternative solutions and technologies.

2.2.1 Overview of APG Utilisation Options

For each site where APG is flared, a number of alternative value chains may be established to recover and utilize part of the gas. The economic viability of each of these APG utilisation options is affected by a large number of factors, e.g. gas characteristics, location and presence of existing infrastructure, market conditions, etc. The optimal solution for a particular site is thus highly case specific.

Different APG streams can have large variations in gas composition and impurities, and thus may require different levels of treatment. The variation in composition also means that different APG streams will provide different product yields and thus different economic values, even when applying the same technological solutions. Some gas utilisation options, such as processing into dry gas, LPG or natural gasoline, have better returns when the recoverable gas stream is “rich”, i.e., when it contains a large portion of heavier hydrocarbons. Other options for APG use, such as large-scale electricity generation, generally work better when the gas is “lean”. An APG stream will always be more attractive when it contains fewer impurities and is at an elevated pressure, due to reduced costs required for treatment and compression.

The alternative options available for utilizing the APG can be categorised as follows:

1. **Reinjection** (for disposal or enhanced oil recovery)
   Reinjection is a purely local option. This is primarily done to maintain the pressure to sustain the level of oil production (Enhanced Oil Recovery - EOR), but the gas may also be reinjected for preservation for future usage (or to be left in the reservoirs, thus avoiding CO2-emissions, as well as providing safe disposal of acid gases). Reinjection is a somewhat uncertain option as different geological foundations to different degrees lend themselves to hold gas. It is thus, for geological reasons, not applicable in all oil fields, and in some regions such as Western Siberia, the region where most of the flaring takes place, the sedimentary rock is not suited for reinjection. Reinjection may in certain cases also be costly, because the gas needs to be compressed before injected into the reservoir. The fact that reinjected gas in itself does not produce any revenues makes this option economically unattractive to oil companies. On the other hand, if the reinjected gas can contribute to enhance oil recovery, reinjection may be a more financially viable option. The advantages and disadvantages of reinjection are presented in Table 2-2.

Table 2-2 Reinjection of associated gas: advantages and disadvantages

Option	Advantages	Disadvantages
Re-inject for future use	Reservoir preservation	Not all formations are suited for reinjection because of high capital cost for local processing and compression
Re-inject for Enhanced Oil/Gas Recovery (EOR/EGR)	Provides revenue through increased oil production, may allow future recovery of re-injected gas	Not all formations are suitable for gas EOR because of high capital cost for local processing and compression

2. **Power generation, local or regional**
   Power generation may be either local or regional. Local power generation produces electricity for use on site, thus saving the oil company expenses in purchased electricity or diesel for power generation. However, not only these facilities are capital intensive, but also the energy needs of an oil field are limited compared to the available power produced from APG. If there are no local consumers (industry or communities) in the vicinity that could take advantage of excess power production, local power generation is thus only a limited solution. Regardless of local or regional consumers, power generation also requires access to a regional power grid to dispose of surplus power. Regional power generation gathers gas from a number of wells, and thus entails even larger processing and infrastructure investments. The revenues from gas sales to electricity generators, assuming a sufficiently high price level for electricity, is however a motivator for oil

producers to go for this alternative. Another option for power generation is the formulation of joint ventures between oil companies possessing neighbouring fields and power generating companies. The advantages and disadvantages of local and regional power generation are summarised in Table 2-3.

Table 2-3 Local or regional power generation: Advantages and disadvantages

Option	Advantages	Disadvantages
Local electricity generation	Savings in purchased electricity or purchased diesel for power generation	Capital cost; field typically requires only 30% of the power that APG could generate. Other local markets may be limited or non-existent
Regional electricity generation	Economic and environmental savings in purchased diesel to generate power – engine of regional integration	Capital cost of gathering and processing infrastructure; low domestic electricity prices limit price offered for gas.

3. **Compression for sale as dry gas**
Another option for APG utilisation is to exploit it commercially as natural gas. APG has a much lower density than natural gas, and as the APG needs to be transported within the natural gas pipelines, it is necessary to compress it beforehand. This process is expensive, and in order to be economically worthwhile, the oil companies need to be able to sell the compressed gas at a sufficiently high price. There is evidently also larger potential for profits if the flow of APG is substantial and stable, allowing for economies of scale.

4. **Processing of APG into liquid products: liquefied natural gas (LNG), liquefied petroleum gas (LPG – propane and butane), petrochemical feedstocks, or diesel (gas to liquids – GTL)**
Processing the gas into LNG, Liquefied Petroleum Gas (LPG), petrochemical feedstocks, and gas-to-liquids (GTL) diesel for sale are other options for utilizing the APG which may generate income for the oil company. These options may however be highly capital intensive, requiring both gathering infrastructure and processing facilities. Both LPG and GTL processing requires external processing facilities, and a certain scale of size is normally required for processing to be an economically viable option. This issue may however be overcome in the relatively near future, as technology is currently being developed for smaller scale GTL processing units. The main characteristics of these products are presented in Table 2-4.

Table 2-4 Liquid products of processed APG

NGL	LPG	LNG	GTL
Consists primarily of molecules heavier than methane like ethane, propane and butane separated from gas as liquids through methods such as absorption, condensation in gas processing or cycling plants; exists as condensate at low pressure, LPG at high pressure, and natural gas at intermediate pressure	A mixture of primarily propane and butanes that exists in a liquid state at room temperature	Natural gas that has been cooled to a liquid form at a temperature of approximately -160 °C and atmospheric pressure; consists primarily of methane	Process of converting natural gas to liquid products like methanol, middle distillates (diesel and jet fuel), diethyl ether (DME), specialty chemicals and waxes

The attractiveness of each of these utilisation options will vary between oil fields due to a number of reasons related to size, location and capital allocation considerations. According to a study by PFC Energy (2007) local electricity generation is the best option for small fields, whereas very large fields that may connect to the power grid may benefit mostly from feeding combined cycle gas turbine (CCGT) power generation.

2.2.2 Technologies for APG utilisation

The above technical options for flaring reduction are based on a set of technological components, which, combined together can form the technical structures needed. The viability of each one of these solutions depends on a number of parameters, thus the optimal solution for a particular site is highly case specific. The technologies related to flare reduction are listed below:

- **APG gathering systems**: *Technologies to collect, gather and compress different gas streams*
  APG is usually separated from the oil using a number of consecutive pressure vessels, resulting in multiple APG streams with different characteristics. When multiple APG streams are to be recovered, a system to gather them into a comingled stream is often required prior to further handling. The APG gathering system typically consists of gas pipelines, dehydration and compression facilities to allow commingling.
- **Gas treatment and processing:** *Key components of gas treatment and processing facilities*
  The main gas treatment processes are compression, dehydration, chilling, fractionation, liquefaction, desulphurization, and CO_2-removal. One of the most common ways to utilize APG is to gather it upstream and supply it to large, centralized gas processing plants (GPPs) to produce dry stripped gas (DSG), LPG (propane-butane mix) and natural gasoline (SNG).
- **On-site use:** *Gas injection, electricity and heat generation*

The amount of excess gas on-site can be reduced by re-injection and additional electricity and heat generation. Re-injection may eliminate all flaring on-site, while the last two gas options normally will only offer a partial solution due to limited demand for heat and power locally.

- **Conversion processes:** *Conversion of APG into e.g. electricity and liquid fuels*
  A number of technologies are available to convert APG fractions resulting from gas treatment and/or processing into potentially more valuable products, such as electricity, heat, petrochemicals and liquid fuels, as well as various energy-intensive industrial products such as fertilizer and steel.
- **Transport options:** *Transport modes for APG and products that can be produced thereof*
  For many flare sites, APG utilisation is facilitated by creating value chains that involve transportation of multiple intermediary and marketable products. Due to differences in transport costs for different products, new facilities and infrastructure established to productively utilize APG could be located if the economic returns of these investments are maximized. In practice, this often implies that GPPs should be located as close to existing product markets and export infrastructure (railways or ports) as possible, relying on long-distance pipeline transportation of APG upstream.

Table 2-5 presents relevant technological components subject to be applied for each of the APG utilisation options described in the previous section. In the next section, these technologies are assessed according to a set of given criteria.

Table 2-5 APG utilisation options and relevant technological components

APG Utilisation options	Technological Components				
	APG gathering systems	Gas treatment and processing	On-site use	Conversion processes	Transport options
Reinjection			√		
Power Generation	√	√	√	√	
Compression for sale as dry gas	√	√			√
Processing into LPG or GTL	√			√	√

2.2.3 Abatement options for methane emissions

There are numerous technological options for reducing methane leakages in oil and natural gas infrastructure. Abatement options for both sectors can be divided into two main categories:

- **Equipment Changes/Upgrades**: For natural gas, replacing high-bleed pneumatic devices – which are designed to release gas during the course of their operation – with low-bleed pneumatic devices would reduce the escape of methane into the atmosphere by approximately 6% from a baseline scenario[6]. This can also be achieved by substituting compressed air for natural gas within pneumatic systems, though at a much higher cost. In the oil sector, abatement can be achieved by installing vapour recovery units to capture natural gas that is vented during crude oil storage, which can then be used to produce energy.
- **Changes in Operational Practices**: "Pump-down" techniques, which remove natural gas from sections of the pipeline before maintenance or repair, could reduce the amount of methane released in the atmosphere by approximately 4% from a baseline scenario[7]. Also, there are new practices which enable maintenance and repairs to be undertaken without shutting down and venting gas from the pipeline. The methane vented during oil production can be captured and sequestered or used in energy uses.

There exist also other emission mitigation techniques which are not widely used. While there is high potential for abatement of methane emissions mainly in the natural gas sector, they are not currently applied as they are prohibitively costly and/or technically restrictive to be feasible at a large scale.

2.2.4 Assessment of UER Technologies

Various key drivers that determine the implementation of an associated gas utilisation project can be identified. These are briefly presented below:

- **Capital cost (CAPEX).** Apparently, is the most critical factor determining the feasibility and viability of a project. CAPEX is related to a series of project related characteristics depending on the project type and more importantly the netback value of the end product.
- **Gas composition and characteristics.** Key aspects of the gas composition include the APG pressure and volume as well as the C3+ content. The contaminants content is also significant; the high CO2 and H2S content lead to increased cost through additional processing, impact on material selection, waste disposal (CO2 and sulphur). Therefore, it is essential to be able to know or estimate the gas composition over the field life.

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[6] Methane emissions mitigation options in the global oil and natural gas industries, Robinson et.al, ICF Consulting

[7] Pumpdown techniques are used to remove gas from sections of the pipeline or a closed chamber with a vacuum pump. EPA (2006)

- **Production profile.** Oil production is often characterised by 'peaky' production profiles and production may be subject to frequent start-stop events, particularly in operations in remote areas. Similarly, associated gas volumes typically vary over the field life. On one hand, a clustering and central processing strategy may be an economically attractive option that also may smooth short/long term production variations. On the other hand, smaller scale facilities are often easier to fund, can be executed faster, and are less technically complex and financially risky.
- **Revenue / Product uplift**. CNG and LNG compete primarily with fossil fuels (e.g. oil, coal) for power generation and domestic heating, while complex products like GTL yield premium prices by competing directly in the transport sector.
- **Maturity of technology.** The maturity of technologies to be implemented is a key factor related primarily to cost, but also to reliability aspects.
- **Transportation to market**. Preference is for a product with high-energy density i.e. a liquid (e.g. GTL, LNG or chemicals).
- **Carbon and energy efficiency** should be considered on a WTW basis where products may displace higher carbon intensive fuels.
- **Community interdependency** may provide an opportunity for interdependency and/or synergies with local communities which may have significant positive effects by both minimizing the risk from the oil development from non-technical risk and may build a local market, reducing transportation costs.

Table 2-6 Qualitative assessment of UER options against a series of key market drivers (Source: GGFR)

	Gas reinjection	CNG	Mini LNG	Small scale GTL	Power generation
Capital Costs					
Gas composition					
Production profile					
Revenue/ Product uplift					
Technology maturity					
Transport to market	Not applicable				
Energy & carbon efficiency					
Operational safety					
Community inter-dependency					

A high level qualitative assessment of available UER categories against the aforementioned aspects is illustrated in Table 2-6, where green colour stands for high/positive prospects, yellow stands for medium prospects and red stands for low/negative prospects.

2.2.5 UER technologies based on renewable sources

Besides venting, flaring and fugitive emissions mitigation, upstream emission reductions may also be achieved by the use of renewable energy sources in the extraction of fossil fuels.

Solar EOR, for instance, is a method for enhanced oil recovery, which is likely to play an important role in the mix of EOR technologies. Instead of burning natural gas to produce steam, solar EOR involves the use of Concentrating Solar Power (CSP) technology to produce steam. Mirrors are used to reflect and concentrate sunlight onto receivers that collect solar energy and then convert it to heat. The heat is then used to produce steam from water. The use of solar EOR could reduce demand for natural gas required for EOR, which can be redirected to other economic activities, such as power generation, water desalination and as feedstock and energy for industrial processes. The technology of solar EOR can also be installed in oil fields with limited availability of associated gas thereby providing a way to create and inject steam for EOR with no capital investment in gas infrastructure. Examples of projects utilizing the technological option of Solar Steam Generation Enhanced Oil Recovery include the oilfields of McKittrick and Coalinga in California as well as the Petroleum Development in Oman.

Other renewable energy applications for the fossil fuel upstream sector include the use of photovoltaic and wind turbines for power generation. These technologies can be used for energy intensive operations in oil and gas fields, such as powering compressors and pumps for transporting oil and gas through gathering pipelines to processing plants, or to generate the electricity and heat needed for on-site operations and living quarters. These activities, however, do not represent an important share of the total upstream emissions of fossil fuels, therefore they do not offer extensive emissions reductions.

2.3 Upstream Emission Reduction Incentives

Fossil fuel companies have various incentives and/or obligations for implementing UER measures irrespective of FQD that are related to legal requirements, own initiatives from improving the technical and financial efficiency of their operations. This section provides an overview of the regulatory requirements, incentives of fossil fuels companies and existing APG utilisation projects in target countries. The analysis will focus on the countries which represent the most important suppliers of fossil fuels to the EU, with an emphasis to the ones that have significant emissions in their upstream activities, as well as those that have implemented successfully upstream emission reduction policies and initiatives.

In order to define the target countries to be analysed, a brief overview of the crude oil supply to the EU, as well as of the main emitting oil producing regions are provided further on.

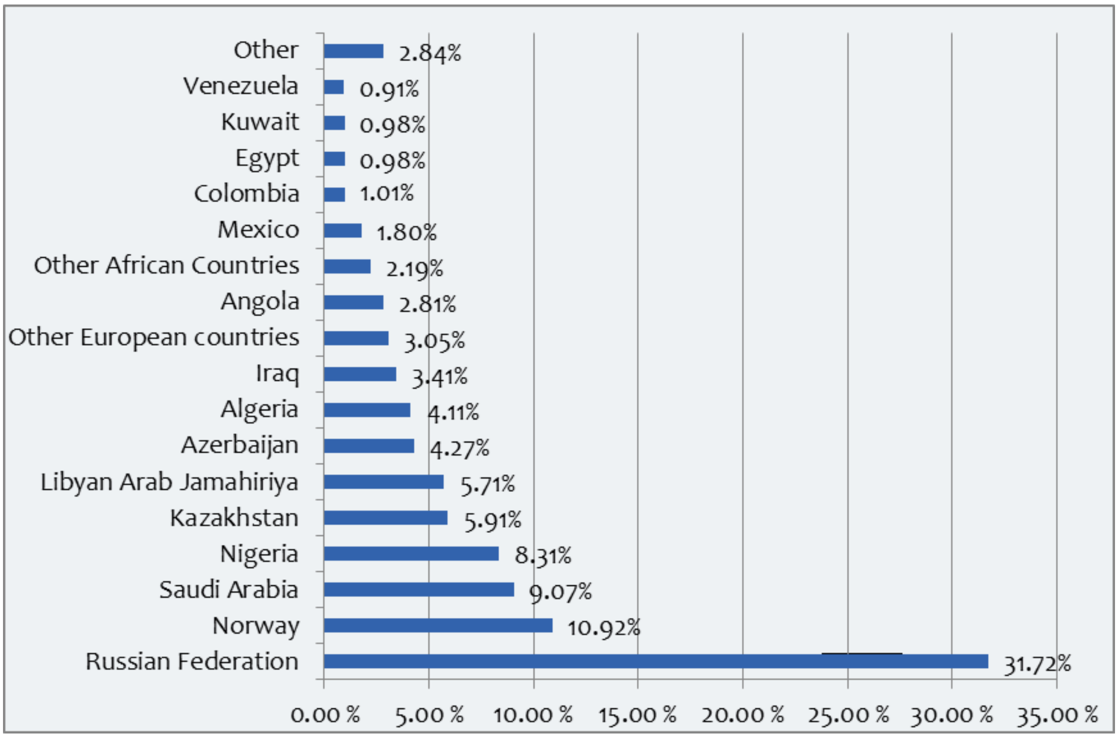
Based on these data, it is reasonable that the overview of UER projects will be limited to the following fossil fuel producing countries:

- Russia
- Nigeria
- Norway
- Middle East (Iraq, Iran[8])
- Canada[9]

2.3.1 Overview of EU crude oil supply

Figure 2-2 illustrates the EU-28 crude oil supply by country of origin in 2012[10].

Figure 2-2 EU crude oil supply by country of origin in 2012 (source: DG ENER)



[8] Iran has been an important supplier of crude oil to the EU for decades; however, the last few years its exports to Europe have decreased significantly due to political reasons. This situation is changing gradually and it is expected that Iranian oil supply will soon be re-established.

[9] Canada is not currently an important crude oil supplier to the EU; however, it is examined in the present section as it has established a successful upstream emission reduction scheme, which will potentially have an effect on the EU oil market, as European regulation is expected to enhance "cleaner" energy supply.

[10] Study on Actual GHG data for diesel, petrol, kerosene and natural gas, EXERGIA-E3M Lab-COWI, 2015

Currently, Russia is by far the largest supplier of oil to Europe, exporting crude oil to Europe from the areas of Urals-Volga, Western Siberia and Timan-Pechora. The second largest supplier of crude oil to Europe is Norway with approximately 11% of total imports. Europe is also supplied with significant quantities of Arabian light and heavy crudes, as well as light and medium crude oils from Nigeria. Apart from the Russian crude oil, Europe is supplied with large quantities of crude oil from other FSU countries, primarily Azerbaijan (Azeri light and Azeri BTC) and Kazakhstan (Tengiz and CPC blend).

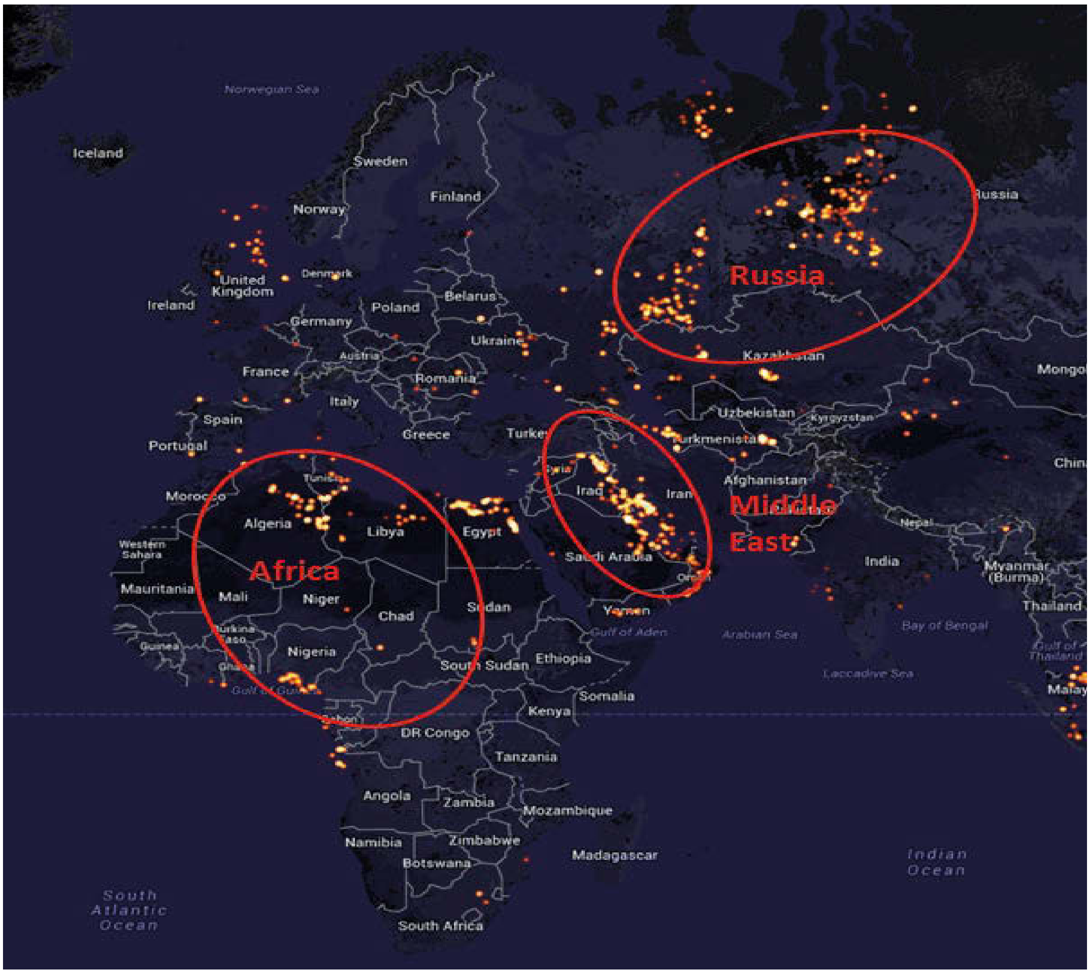
2.3.2 Geography of upstream emissions

A small number of countries are dominant contributors to global flaring emissions. In 2009, Russia and Nigeria accounted for an estimated 42 % of global flaring. Twenty countries accounted for an estimated 85 % of the observed flaring. Much of the official information on the amount of gas flaring comes from environmental ministries or statistical agencies within various governments. However, during the last decade, increased use of military satellites and sophisticated computer programs has been used to measure gas flaring. These efforts seek to correlate light observations with intensity measures and flare volumes to produce credible estimates of global gas flaring levels.

The National Oceanic and Atmospheric Administration (NOAA) in collaboration with the World Bank's Global Gas Flaring Reduction (GGFR) Partnership has conducted an extensive work on the elaboration of actual data for flaring both on a country and field level, using processed satellite data. The geographic dispersion of flaring gas is depicted in Figure 2-3, where it is evident that most of flaring activities take place in three key areas:

- Russia and Former Soviet Union countries
- Africa (mainly Nigeria, Algeria and Angola)
- Middle East (mainly Iran, Iraq and the Persian Gulf)

Figure 2-3 Map of satellite flaring estimates (Source: VIIRS)

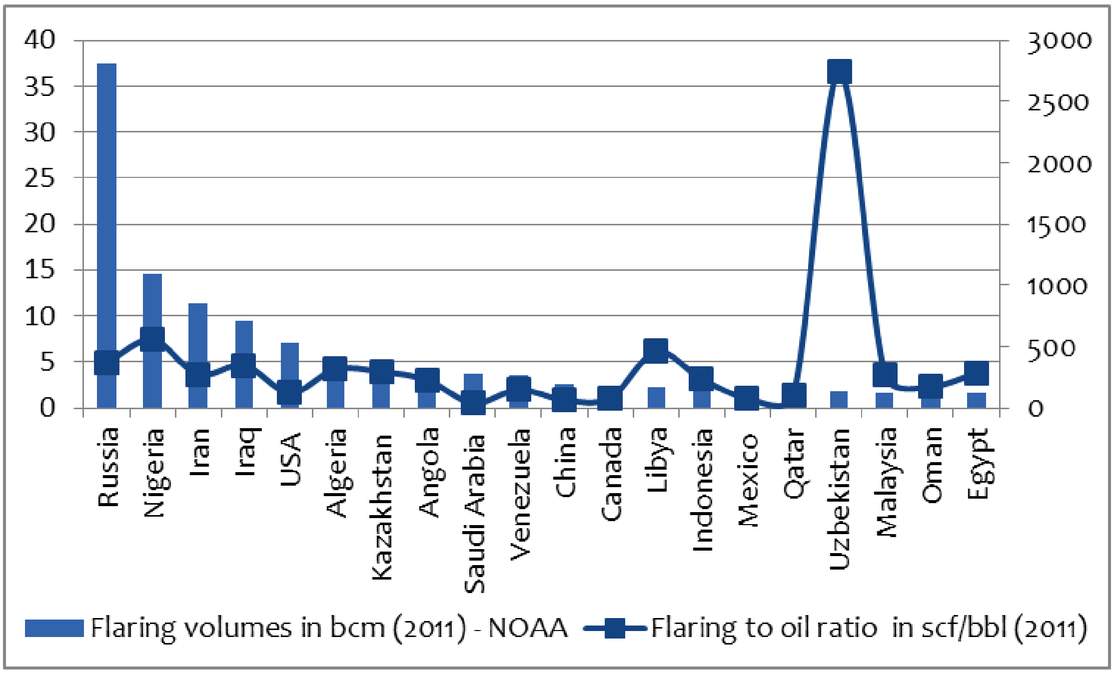


Flaring emissions from Russian oil fields are extremely high - the largest among all oil producing countries. According to the World Bank's GGFR satellite studies (2011), Russia was in 2010 by far the country in the world flaring the biggest amount of associated gas (34.2 bcm), followed by Nigeria (15.2 bcm), Iran (11.3 bcm) and Iraq (9.1 bcm). The total global volume of flaring in 2010 according to the World Bank was 134 bcm.

As it can be obtained from Figure 2-4, Russia has one of the largest flaring to oil ratio among countries studied by NOAA (i.e. associated gas flared volume per unit of oil extracted). The relevant ratio has been calculated by using gas flared volumes by NOAA/GGFR estimates and EIA oil production volumes per country[11].

[11] Study on Actual GHG data for diesel, petrol, kerosene and natural gas, EXERGIA-E3M Lab-COWI, 2015

Figure 2-4 Flaring emissions (in bcm) according to the NOAA/GGFR database and flaring to oil ratio (scf/bbl) for the calculated based on EIA production volumes for 2011



2.3.3 Russia

In the last few years, big Russian companies have started to realise the economic benefits of utilizing the associated gas due to the increasing gas prices in their own country. Nine large vertically integrated oil companies account for approximately 90% of Russia's national crude oil production. They include the majority state-owned companies Rosneft and Gazprom (including Gazprom Neft) and seven privately owned or publicly traded companies: Lukoil, TNK-BP, Surgutneftegaz, Tatneft, Bashneft,RussNeft and Slavneft. One of the largest companies, Surgetneftegas, has initiated investments in gas turbine power generators and pipelines, and they plan to utilize 97% of the APG in the fields where they operate in the near future. However, the gas or electricity demand in oil fields and in local communities nearby is usually much lower than the amount of produced associated gas. Gazprom's monopoly on pipeline network, gas processing and gas exports limits the options for gas utilisation. In addition, Gazprom holds a monopoly on Russia`s export of natural gas to European markets and oil producers are obliged to supply processed APG only in the domestic market, however at a much lower prices.

According to GGFR estimates there has been a considerable reduction in Russian flaring volumes from 2006 to 2010, showing a decline from 50 bcm to 34.2 bcm. From 2009 to 2010 the gas flaring reduction in Russia was particularly striking, from 46.6 bcm to 34.2 bcm from one year to the next.

The main reason for non-utilisation of APG is simply that it is considered unprofitable, since in many cases the marginal cost of utilizing the gas is higher than the potential economic revenue. Table 2-7 summarises[12] the main reasons for non-utilisation of APG in Russian oil fields.

Table 2-7 Summary of reasons for non-utilisation of APG in Russia

Technological Reasons	Economic Reasons	Institutional Reasons
› Lack of production and processing infrastructure › Deficiencies in APG metering › Underdeveloped oil-gas processing complex › High capital intensity in constructing gas pipelines › Absence of high-performance low-power equipment for the fractional separation of APG	› Low domestic prices on natural gas › Long distances between production and potential markets › Few incentives for investments › Insufficient penalties for emitting APG combustion products (pay to pollute) › Zero mineral tax-rate on flared gas	› Gazprom's monopoly on gas transport limits third-party access to pipelines › Many laws, but none that considers APG independently › Inefficient system for state control and monitoring of flaring / Competition between various government agencies › Regulatory/legal base deficiencies › SIBUR monopoly on processing facilities

Upstream emissions regulation

The lack of efforts to value associated gas in Russia is due to the absence of competitive markets for gas and other fuels. The government of Russia has made some efforts to help reduce flaring and venting by punitive methods, such as increasing the methane emission fees for flaring associated gas. These efforts started in 2005, however, it is very unclear how strictly and effectively these regulations are being enforced by the government. In January 2009 a Decree on flaring was approved – requiring a minimum level of 95 % utilisation of APG. The decree entered into force on January 1, 2012. The petroleum industry thus had three years to prepare and invest in necessary technology solutions. However, the official Russian statistics show that there has not been sufficient flaring reduction to reach the target level. In spite of increased fees for excessive flaring from January 2012, it is often cheaper to pay the fines than to utilize more APG.

Government Decree No. 1148 of 8 November 2012 sets the multiplier at 12 for penalties on emissions greater than 5% of produced APG and raises the multiplier to 25 as of 2014. In the absence of acceptable measuring equipment at a field, penalties are multiplied by a factor of 120, although it is not clear how this is to be calculated in the absence of

[12] Sources: Knizhnikov and Poussenkova (2009), Ermolovich (2011), PFC Energy (2007)

metering. This Decree allows producers to subtract investment costs for APG utilisation projects from the fines, including for investments in gas pipelines, compressor stations, separation units, facilities producing electricity and heat and for re-injection. It also allows a company to reach the 95% utilisation target by aggregating production across all of a company's fields. However, if the company is not able to reach this rate through aggregation, fines are calculated for each field individually. While this flexibility could lead to some economic efficiency in targeting APG utilisation investments, it could disadvantage companies that have a small number of fields.

The licenses issued by the Ministry of Natural Resources to oil and gas producers include the permission to process and sell associated gas, re-inject it in the reservoir, utilize it in the facility or produce electricity, or even flare specified amounts. In some regions, most notably in Khanty-Mansiysk and Yamalo-Nenets, it is mandatory to include an APG utilisation percentage in the licence agreement.

Carbon credits

Following a protracted process and delays, Russian authorities established procedures to approve projects developed under the so-called Joint Implementation mechanism of the Kyoto Protocol and to issue Emission Reduction Units (ERUs) that can be sold in the international carbon markets. The first project approvals were made in July 2010, and the first carbon credits were issued in December of the same year. Over 20 flaring-related Joint Implementation projects have been approved, and such projects now represent one of the largest categories of approved Joint Implementation projects in Russia. However, since 2011, Joint Implementation projects have become less important, partly because of a price collapse for carbon credits and partly because Russia took the decision not to join the second commitment period under the Kyoto Protocol, hence making new Russian carbon credits from such projects ineligible in carbon markets. It now seems unlikely that the emission reduction benefits of new APG projects will have any economic value for investors in the near future. However, there are processes internally in governmental institutions in Russia to design a national emissions trading system (a cap-and-trade scheme)[13].

Overview of APG utilisation facilities

The main APG utilisation activity in Russia concerns gas processing plants. In 2010, 48% of produced APG was supplied to **gas processing plants**, where it was used as feedstock for production of marketable hydrocarbon products such as dry stripped gas, liquefied petroleum gas and stable gas condensate. Due to the high liquid content of many APG streams, expanding gas gathering networks and increasing the available gas processing capacity represents one of the most promising options to reduce flaring in many oil-producing regions in Russia, particularly in areas with significant existing infrastructure.

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[13]Associated Petroleum Gas Flaring Study for Russia, Kazakhstan, Turkmenistan and Azerbaijan, Carbon Limits, 2013

Apart from the oil companies by whom APG utilisation is mostly seen as an obligation, there is another actor in Russia that has APG processing as its main occupation – **SIBUR**. SIBUR utilises around 17 bcm of associated gas, which amounts to 57% of the total volume of associated gas processing in Russia. The company renders deep APG processing, thus producing petrochemicals with high value added. In order to ensure continuous supply of APG to its processing facilities SIBUR aims at creating long-term partnerships with oil companies. In 2010, 56% of processed APG was supplied to gas processing plants (GPPs) controlled by SIBUR. Some upstream operators have entered into joint ventures with SIBUR to secure long-term contracts for access to the latter's processing capacity and for sales of processed products.

Surgutneftegaz[14] and Tatneft are among the few companies in the industry that do not use processing plants belonging to SIBUR since they own large gas processing plants that were built decades ago: Surgut Gas Processing Plant and Minnibaevo Gas Processing Plant. As Tatneft for years has been processing APG and supplying the products of its processing to the petrochemical industry, Surgutneftegaz plans in the long term to produce advanced petrochemicals at the company's facilities. The main share of APG produced by Surgutneftegaz has through the years been supplied to **high-capacity power plants** in the region: Surgut State District Power Stations. Around 70% of the APG produced by the company in 2010 was supplied to these power plants and, in addition, its own electricity production constituted more than 30 percent of its total electricity consumption, ensuring the company's technological processes, heating of houses, buildings and car parks[15].

Major recent projects in associated gas processing facilities are summarized in Table 2-8. The list is not exhaustive; however it presents a number of important projects in Russia.

[15] Reducing gas flaring in Russia: Gloomy outlook in times of economic insecurity, Julia S.P. Lowe, Olga Ladehaug, Poyry, 2012

Table 2-8 Major recent APG utilisation projects in Russia

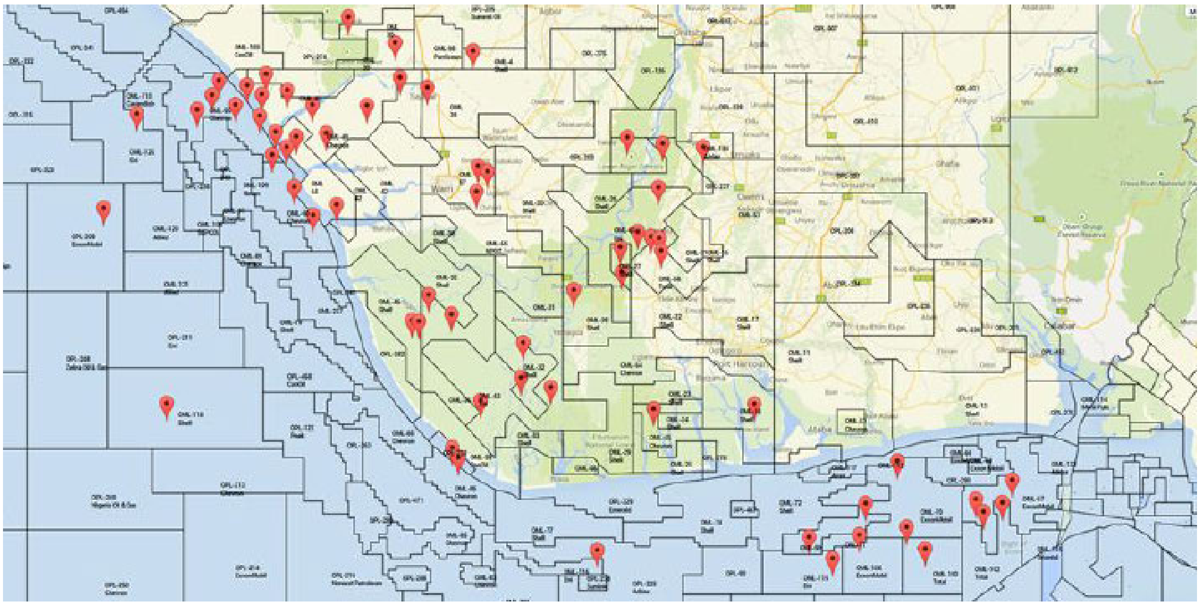
Company	Project Description	APG Utilisation option	Date of operation
Surgutneftegaz	Surgut State District Power Stations	› Sale of dry gas › Power generation	Operation of third plant started in 2006
	Talakanskoye oil field in the Republic of Sakha	› Reinjection › Power generation	2011
Surgutneftegaz and others	Gas processing enterprises of Ugra	› Sale of dry gas and LNG › Production of light hydrocarbons and gasoline	2013
Rosneft	Booster compressor station (BCS) and gas treatment facilities at the Odoptu-More	› Sale of dry gas	July 2011
	Yugragazpererabotka processing plants (In collaboration with SIBUR)	› Sale of dry gas	Expected
	APG power complex at the Priobskoye field	› Power generation (gas preparation facility and a 180 MW gas turbine electric power station)	2010
	Associated Petroleum Gas Recovery for the Kharampur oil fields of "Rosneft"	› Sale of dry gas (connecting to Gazprom transmission system)	2012
	Komsomolskoye oil field APG recovery	› Power generation › Sale of dry gas	March 2011
TNK-BP	Pokrovskaya gas treatment unit in Orenburg	› Sale of dry gas	2012
	APG utilisation unit in Verkhnechonskoye field in the Irkutsk Region	› Sale of dry gas	Expected
Lukoil	Various projects including: › Gas turbine power plants at Krutovskoye field of OOO LUKOIL-Perm, Tavdinskoye field, and Tokarevskoye field of OAO RITEK; › Gas compressor stations at the following fields: Severo –	› Power generation › Sale of dry gas	2011-2013

Company	Project Description	APG Utilisation option	Date of operation
	Kozhvinskoye, Zapadno – Tebukskoye of OOO LUKOIL-Komi, Troelzhskoye, Aryazhskoye of OAO RITEK; › A compressor station to inject the gas into the formation at the Sredne-Khulymskoye field of OAO RITEK; › Five oil heaters at Dubravnoye, Yuzhno – Kondrashevskoye, Rusakovskoye, Kasibskoye, Ocherskoye fields of OAO RITEK; › Two multiphase pump stations at Kalmiyarskoye and Khatymskoye fields of OAO RITEK;		

2.3.4 Nigeria

Gas flaring has been a continuous issue in Nigeria. Nigeria accounts for just over 2% of global oil production and about **10% of gas flared globally in 2011**. Only 40 % of daily gas production is re-injected or used commercially, while 50 % is flared causing environmental and health problems. Nigerian oil and gas companies emit 44 million tons of CO2 per year. Economic and fiscal responsibilities of the international petroleum companies and the powerlessness of the government to enforce compliance with the laws and regulations against gas flaring are the main sources of the problem. The most important flares in Nigeria are shown in Figure 2-5.

Figure 2-5 Map of Nigeria's most important flares (Source: NNPC & GGFR)



Upstream emissions regulation

In 1979 the Nigerian government signed the Associated Gas Re-Injection Act, where it was declared that the companies are forbidden to flare the gas produced with oil after 1 January 1984 without the admission of the Minister. Nevertheless, the Nigerian authorities did not succeed in forcing the companies to keep the deadlines.

Deficient governance of the oil sector marked by the lack of an independent regulator and a history of payment defaults on the part of the Nigerian National Petroleum Corporation (NNPC) and the power utility, combined with some unstructured regulation like the recent directive by the Ministry of Petroleum Resources (MPR) urging oil companies to give flared gas to 3rd party investors for APG utilisation projects has sparked much controversy among oil majors operating in the country. MPR is both a participant in, through the NNPC, and regulator of oil and gas activities in Nigeria, creating conflicts of interests reflected in the lax enforcement of flaring regulation. At the same time as a joint--venture partner at a very high level (around 60%), NNPC has been more than 1--2 years late in paying its equity share of cash calls. Furthermore, the pricing policy of gas supply and power are seen by the investors as a disincentive to develop flaring reduction projects.

International oil and gas producers, such as Shell, have reported that they reduced flaring by 60 % in Nigeria between 2002 and 2008. One-half of the reduction is achieved through gas gathering and associated gas utilisation projects and another half is carried out due to security issues. Nevertheless, the real data show that between 1999 and 2008 the gas flaring decreased by 12 % only[14].

The Nigerian Government has introduced in 1998 fiscal incentives for international companies in order to attract more investment into flaring reduction projects. These fiscal incentives can be summarised as follows:

- a value added tax (VAT) and customs-duty exemptions on plant, machinery and equipment;
- a five-year tax holiday;
- an accelerated capital allowance after the tax-free period in the form of 90%, with 10% retention on the books for investment in plant and machinery;
- a 15% investment capital allowance that shall not reduce the value of the asset;
- tax-free dividends during the tax-free period;
- tax-deductible interest on loans for associated gas utilisation projects.

In 2007 the Nigerian government has created a Gas Master Plan. The idea of the plan is to stimulate the domestic use of natural gas by developing the infrastructure and introducing competition and open access. The authorities are intended to provide support by looking at initial increases in high-pressure transmission and better fulfilment of existing gas pipelines by the international oil companies[16].

A controversial Petroleum Industry Bill (PIB) issued in 2012 intended to raise taxes on International Oil Companies (IOCs) creating a comprehensive legal framework for the exploitation of gas and petroleum resources in the country. The proposed legislation was designed to strengthen the capacity of indigenous Nigerian companies in the oil and gas sector to compete with international oil companies in the search and acquisition of hydrocarbons in Nigeria. The PIB has seen numerous modifications since 2012 and is currently under debate.

Overview of APG utilisation facilities

To date there are various projects and master plans on the way helping to reduce gas flaring. The West African Gas Pipeline Company owned by Chevron, Nigerian National Petroleum Corporation and Shell has created a plan to build a new 684 km gas pipeline to connect different oil fields across Sub-Saharan Africa. As a result the CO2 emission is to be reduced by 78 million tonnes.

Moreover, GTL technology is also used to reduce flaring. One of the first projects in Nigeria was Sasol Chevron in Escravos. The plant has the capacity to refine 300 mcf per day of gas to GTL diesel and GTL naphtha for further marketing in the EU and US. Other GTL projects are introduced, however this technology is new and it will take time to implement these projects.

Some of the most significant APG utilisation projects operating in Nigeria are presented in Table 2-9.

Table 2-9 List of significant APG utilisation projects in Nigeria

Project	Operating Company	APG Utilisation option	Date of operation
Eni Okpai power plant	Eni	› Power generation › Sale of dry gas	2005
Shell Afam power plant	Shell Petroleum Development Company of Nigeria (SPDC)	› Power generation	2008
NLNG (one of the most significant APG use projects in Nigeria)	NNPC	› Sale of LNG	1999
Exxon Mobil Oso condensate project	Exxon Mobil	› Production of Natural Gas Liquids	1991

[16] Efforts to reduce flaring and venting of natural gas world-wide, Norwegian University of Science and Technology, November 2012

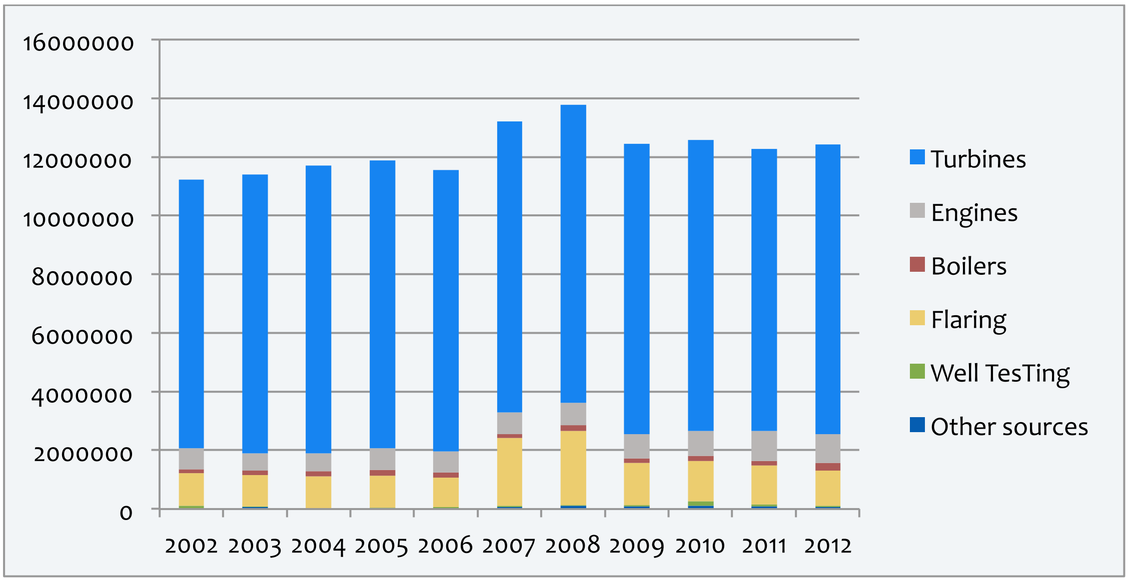
Project	Operating Company	APG Utilisation option	Date of operation
		(NGL)	
Chevron Escravos project	Chevron	› Production of GTL (diesel and naphtha)	2014
Onshore Gas asset management	Chevron	› Sale of dry gas	2014
Ofon field flare-out	Total	› Sale of LNG	2015
Akri flare down	Nigerian Agip Oil Company (NAOC)	› Sale of dry gas	2015
Southern Swamp AGG	SPDC	› Sale of dry gas	Expected in 2016
Gbaran ubie phase 2	SPDC	› Sale of dry gas	2013

2.3.5 Norway

The environmental performance of the Norwegian petroleum sector compared to other oil producing regions worldwide is one of the cleanest. This has been the result of a number of policy instruments and regulations deployed by the Norwegian government to regulate emissions from the oil and gas business. The most important of these include the carbon tax, Norway's participation in the EU emission trading market, flaring restriction provisions in the Petroleum Activities Act and the requirement to assess power from shore when planning developments. These instruments have prompted a number of measures by the petroleum sector that led to significant emissions reductions over the last years.

The Climate and Pollution Agency, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database for reporting emissions to air and discharges to sea from the petroleum activities under the name «Environmental Web». In addition, all operators on the Norwegian continental shelf report GHG emissions and discharge data directly into the database. All these data are characterised by high consistency and transparency.
After a peak in 2008 GHG emissions have declined sharply in 2009 and in general terms remained steady until 2012, as it can be seen in Figure 2-6. The main source of atmospheric emissions has been power generation using natural gas and diesel. The level of these emissions depends mainly on energy consumption by the facilities and the energy efficiency of power generation. The second largest source of this emission type is gas flaring. Flaring takes place to only a limited extent and is constantly decreasing pursuant to the provisions of the Petroleum Activities Act, but it is permitted for safety reasons and in connection with certain operational problems, thus it represents only a small fraction of upstream emissions (in 2008 gas flared was as little as 0,16% of the total annual APG from oil production).

Figure 2-6 Breakdown of GHG emissions by source in metric tons CO2 equivalent for Norway (source: NPD)



Upstream emissions regulation

The CO2 tax on gas flaring has been a powerful tool for regulating flaring and incentivising APG use in Norway. Pursuant to the **CO2 Tax Act**, the use of gas, oil and diesel in connection with petroleum activities on the continental shelf is subject to a CO2 tax as of 1 January 1991. In line with Norwegian climate policy, the CO2 tax for the petroleum activities has increased over the years and the fee is 0.16 USD per standard cubic meter (Sm^3) of gas and litre of oil or condensate, effective on 1 January 2013.

Furthermore, Norway is part of the EU's emissions trading system (EU ETS). This entails that the EU's Emission Trading Directive with associated decisions applies to Norwegian petroleum activities and those are therefore subject to mandatory allowances in line with the activities subject to mandatory allowances in the EU.

The **Greenhouse Gas Emissions Trading Act** was enacted in 2005 and was amended in April 2011. The third emissions trading period started on 1 January 2013, and will run until 2020. As of 1 January 2008, the petroleum activities are subject to both a CO2 tax and mandatory emissions allowances.

The 1996 **Petroleum activities Act** bans flaring except with permission from the Ministry: "*Flaring in excess of the quantities needed for normal operational safety shall not be allowed unless approved by the Ministry*":

- Associated gas utilisation is required to get authority approval of the Plan for Development and Operation
- Annual gas flaring permits
- Avoid waste of petroleum and reservoir energy
- Cold venting is not in accordance with the principle of environmentally prudent petroleum production

The Norwegian legal framework aiming at the reduction of flaring and the enhancement of APG use is summarised in Table 2-10.

Table 2-10 Summary of Norwegian legal framework on gas flaring and APG utilisation

Oil Operator	Government
Measuring: › Operators who are flaring and venting APG during operational phase are responsible for establishing the internal control system for ensuring compliance, such as obligation to check sensor calibration every six months. › Operators are responsible for keeping an emissions inventory with requirement to submit to the Norwegian Petroleum Directorate (NPD) before March 1 of each year.	**Measuring:** › NPD supervises internal control systems for operators to verify that petroleum activities are carried out in accordance with authorities' requirements and accepted by companies' criteria goals › Also it observes (audits) the application of the equipment that measures quantity of gas used for flaring and venting.
Reporting: › Operating company that holds flaring permit has to submit a report to the state authorities, indicating the amount of gas flared daily. › Every six months it has to report on volumes of the flared gas for tax purposes.	**Reporting:** › Obtaining and evaluating reports submitted by oil operators.

The enforcement of this regulatory framework is however facilitated by the proximity of the country to huge markets for natural gas, combined with an existing gas pipeline transportation infrastructure that can access those markets. Thus, in Norway, reducing flaring of APG is much easier and less expensive to achieve than in other countries, such as in Africa.

Overview of APG utilisation facilities

Most of the **APG produced in Norway is exported** to the European market and this gas export, enabled by a strong pipeline network and proximity to market along with the CO_2 tax has played a significant role in reducing gas flaring in the country. The **remaining associated gas that is not exported is reinjected,** in order to maintain the pressure and flow rate of the oil being produced. By using the associated gas in the production, they are able to recover much higher percentage of oil than if they were to simply inject water for example. The natural gas can later be produced and sold when crude oil production ceases. In the case where this is not necessary, or not possible, the gas can also be used to produce electricity in gas-fired turbines. That way the gas isn't just wasted on flaring, but can be an energy source to provide power for industry operations, such as pumping, compression machines and gas processing. The electricity can even be sold, if they it is not consumed entirely in the field.

Reinjection of APG

Since injection of natural gas started in Norway in year 1975 the fields operators have been able to recover 2-2,3 billion additional barrels of oil and condensate. Examples of reinjection procedures in Norway include:

- **Ekofisk field** which increased the recovery rate from 17-18% to 50%
- **Oseberg field** which has a recovery rate of 63%
- **Statfjord field** which has a recovery rate of 66%

Best practice – Case studies

1. Gulfaks project: Zero continuous flaring technology

Statoil through its Gulfaks oil field developed a system to end continuous flaring by recycling the flare gas. The flare ignition system only operates in emergency situations. The technique that has been implemented involves routing the gas which was previously flared back to the existing gas export system through a pipeline network with a valve that can quickly divert the flow to the flare stack if the pressure starts to increase. Since 1994, Gulfaks A and C platforms have operated the first zero normal flare system. Since the adoption of this technology in Gulfaks, it has also been implemented in nearly 30 Norwegian offshore installations, as well as in the UK, Azerbaijan and Angola.

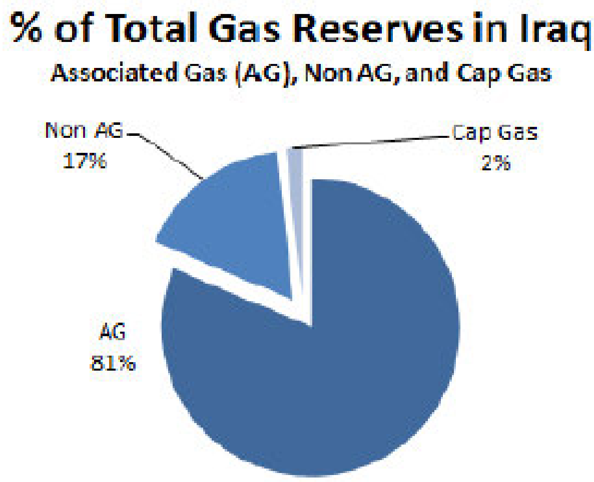
2. Far North Liquids and Associated Gas System (FLAGS)

The FLAGS pipeline is a natural gas pipeline, operating since 1982, used to transport associated gas and liquids from multiple platforms. It starts at the Brent oil filed and ends at St. Fergus in Scotland. APG from the Statfjord field in Norway is transported to the FLAGS pipeline via other smaller connected pipelines, allowing transport of the Norwegian gas to the UK.

2.3.6 Iraq

To date, natural gas deposits in Iraq are predominantly found in an **associated form with oil, constituting approximately 81% of the total reserves**, leaving 2% as associated (cap gas) and 17% as non-associated gas (Figure 2-7). Thus, it is clear that levels of overall gas production will be heavily linked to the oil production profile, due to the large percentage of associated gas.

Figure 2-7 Distribution of gas reserves in Iraq (Source: Iraq Energy Institute, 2013)



In January 2013, Iraq's gas production reached 2.234 bcf/day. Currently, only 400 mcf/day is captured from the south and 300 mcf/day is captured from the north, leaving 1.2 bcf/day wastefully flared because of the lack of infrastructure and other persistent challenges. In addition, 340 mcf of free gas (non-associated gas) was commercially produced from the northern field of Khor Mor.

At present there is no specific regulation in place aiming to reduce the amounts of gas flared and to promote utilisation of associated gas. However, there have been some efforts to take advantage of the wasted gas that accompanies oil extraction activities by state owned operators, mainly for economic reasons.

Overview of APG utilisation facilities

The Kirkuk-based North Gas Company operates twenty-three degassing stations at oil and gas fields across central and northern Iraq. Twelve gas-compressor stations collect associated gas before feeding it to a gas processing plant at Kirkuk to produce LPG, dry gas, natural gasoline, and sulphur. The Kirkuk gas processing plant consists of two trains with a total capacity of 1.2 million tonnes annually of LPG.

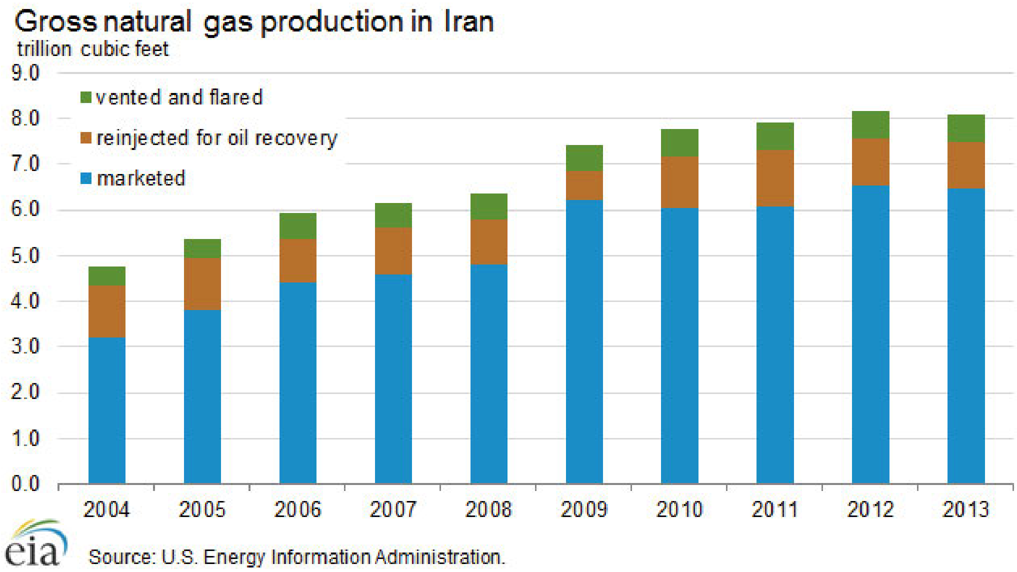
The Basrah-based South Gas Company has formed a joint venture with Shell, which is responsible for gathering and processing associated gas from twelve degassing stations in the southern oil fields to produce dry gas and natural NGLs, as well as operating LPG storage facilities and export terminals. The company operates on four main sites: the North Rumaila NGL plant, the Khor al-Zubair NGL/LPG plant, the Iraqi Storage Terminal and Iraqi Receiving Terminal, and the LPG shipping terminal at Umm Qasr. The North Rumaila NGL plant had a capacity of associated gas processing of 680 mcf/day, but is currently operating at 20-35 % of that capacity due to the lack of gas supplies. The Khor Al-Zubair NGL/LPG plant separates liquids from raw gas to produce propane, butane, gasoline, and dry gas and has the capacity to produce 4 million tonnes per annum of propane and butane, plus 1.5 million tonnes annually of gasoline. The decline in processing rates at both North Rumaila and Khor al-Zubair are largely due to the need for rehabilitation; there is an insufficient number of compressors at the oil fields and an absence of gas pipelines from the West Qurna and Zubair fields to the processing units. In 2008, the State Company for Oil Projects awarded contracts to the Italian division of GE Oil & Gas to renovate the existing compressors, as well as to build new ones and construct gathering stations in the West Qurna and Zubair fields[17].

The Basrah Gas Company (BGC), which has been operating the flare reduction project since 2013, has been awarded the World Bank's prestigious Global Gas Flaring Reduction Partnership (GGFR) Excellence Award for 2015.

2.3.7 Iran

Iran is the world's third-largest dry natural gas producer, after the United States and Russia. Despite repeated delays in field development and the effects of sanctions, Iran's natural gas production is expected to increase in the coming years as new phases of the South Pars gas field come online. In 2013, Iran became the world's largest gas-flaring country, surpassing Russia. The evolution in Iran's natural gas production is presented in Figure 2-8.

Figure 2-8 Natural gas production in Iran (Source: U.S. EIA)



According to the latest official statistics, Iran's total flared gas amount has remained unchanged since 2011 at about 40 mcm/day.

GGFR reports that Iran has the third place among all countries in terms of flaring gas for 2011. New statistics are unavailable, but comparing GGFR's figures with Iran's latest statistics indicates there has been no progress. In total, 360 million tonnes of CO_2 were released into the atmosphere by burning 140 bcm of flared gas in 2011.

[17] Natural Gas in the Republic of Iraq, Luay J. al-Khatteeb, Iraq Energy Institute, November 2013

The US Energy Information Administration also reported in March 2013 that Iran's flared gas amount in 2011 was about 45 mcm of gas per day. During this year, about 30% of Iran's total associated natural gas production was flared.

Overview of APG utilisation facilities

The AMAK project in Iran, which was commissioned in February 2005, is the most extensive environmental project implemented by the National Iranian South Oil Company, to collect associated gas from one of the reservoirs in the Ahwaz oil field in Southern Iran. The project was so big that they needed to construct seven sour gas compressors, one acid gas compressor, a sweetening plant, 280 km long gas pipeline and 100 km of power lines. The goal of this project is to prevent flaring of 7 mcm of sour gas per day.

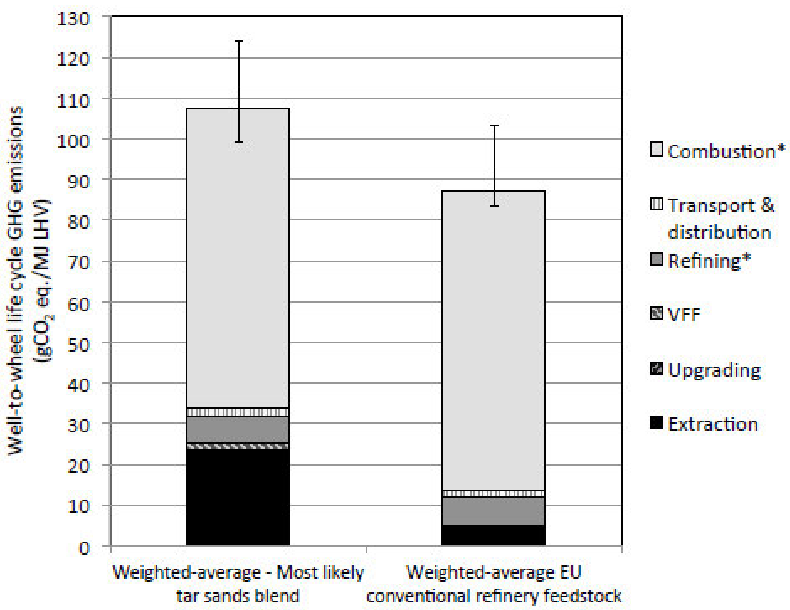
A number of other APG utilisation projects are expected to be operational soon, including the Kharg and Baregan associated gas gathering and NGL project, which involves the construction of a gas treatment plant and an NGL recovery facility at Kharg Island in Iran. The two facilities will receive and process gas from both onshore and offshore sources. About 300 mcf/day of gas will be gathered from offshore fields and another 300 mcf/day from onshore processing facilities. Onshore gas will be fed from the Aboozar, Dorood I, II and III and Foroozan oil processing facilities. Offshore gas will be gathered from the Aboozar, Bahregansar, Foroozan, Nowrooz and Soroosh fields. The project will help in reducing flaring of 600 mcf/day up to 700mcf/day of gas from these fields.

2.3.8 Canada

Canada is one of the most important **unconventional oil** producing countries in the world. Its resources of crude oil were estimated to have a remaining potential of 339 billion barrels as of December 2012. Of this, **oil sands account for 90%** and conventional oil 10%. There are two major producing areas in Canada, the Western Canada Sedimentary Basin, which includes Alberta, Saskatchewan and parts of British Columbia and Manitoba, and offshore eastern Canada. Although Canada is the sixth largest producer in the world, it produces only about 4% of total daily production. In 2013, **71% of Canadian crude production was exported to the U.S.** and only 2% was exported to overseas markets.

The EU is not currently being supplied with oil from Canada, as unconventional fuels - which are far more emitting than conventional ones - are generally not traced in the EU energy balance. However, it is anticipated that unconventional crude oil from Canada will be imported in Europe in significant quantities in the future. The reason is that Canadian authorities have imposed very strict regulations on upstream emissions, thus the EU initiative for “cleaner” fuels will drive the market towards new suppliers, such as Canada. The total emissions of Canadian crude oil pathways (tar sands), compared to the weighted average of EU crude pathway are presented in Figure 2-9.

Figure 2-9 Oil sands emissions compared to conventional EU refinery feedstock emissions



The analysis of lifecycle GHG emissions of unconventional crude oils is different compared to conventional crude oil, due to different extraction techniques and processing prior to refining. Bitumen is often diluted with liquid hydrocarbons or converted into a synthetic light crude oil. Several kinds of crude-like products can be generated from bitumen, and their properties differ in some respects from conventional light crudes.

Alberta bitumen

Alberta has the largest oil sand deposits globally. Each area is covered by a layer of overburden consisting of muskeg, glacial tills, sandstone and shale. Bitumen is extracted by two means - mining and in situ:

- **Mining.** Oil sands deposits that are less than approximately 75 meters below the surface can be removed using conventional strip-mining methods. Approximately 20% of currently recoverable reserves can be mined. The strip-mining process includes removal of the overburden, excavation of the bitumen, and transportation to a processing facility. Strip-mining techniques entail increased land use changes resulting in higher intensities of GHG emissions.
- **In-situ.** Oil sands deposits that are deeper than approximately 75 meters are recovered using in-situ methods. Most in-situ recovery methods involve injection of steam into an oil sands reservoir to heat - and thus decrease the viscosity of - the bitumen, allowing it to flow out from the reservoir to collection wells. In-situ methods are generally more GHG intensive compared to conventional mining – leaving aside land use impacts – due to the fact that significant amounts of energy are required to create steam.

The largest part of unconventional deposits until very recently was extracted via conventional mining techniques. In 2011, according to Alberta oil and gas industry, approximately 51% of oil sands production came through mining extraction. Currently, approximately 2/3 of oil sands are extracted via in-situ methods and approximately 1/3 via mining. Alberta in the future will rely to a greater extent on in-situ production, as 80% of the province's proven bitumen reserves are too deep to recover using conventional mining techniques.

Upstream emissions regulation

The largest emitting provinces of Canada, in terms of upstream activities are Alberta and British Columbia. Both of these provinces have taken legislative measures aiming at reducing their upstream emissions; at the same time, both Alberta and British Columbia possess their own regulated offset mechanisms.

Alberta

Alberta is the country's largest emitter but was also the first province to regulate greenhouse gas emissions with the 2003 Climate Change and Emissions Management Act (and later the Specified Gas Emitters Regulation). Existing facilities that emit more than 100,000 tonnes of greenhouse gas per year have to cap their emissions intensity at 12 per cent below their average for 2003-2005. Facilities built in the last 15 years can phase in the cap over eight years.

Emissions intensity doesn't measure emissions in absolute terms but factors in GDP to measure GHG as a unit of production. This means that if production increases, emissions can increase and still fall within the target. Alberta has estimated that its absolute emissions won't begin to decline until 2020.

Large final emitters are required to reduce their GHG intensity by up to 12% per year, as part of the 2002 Climate Change and Emissions Management Act (CCEMA) and the 2007 Specified Gas Emitters Regulation passed by the Alberta legislature, by paying a penalty of $15 for every tonne over their limit. The money is invested in emission reduction technologies by the Climate Change and Emissions Management Corporation. Emitters can purchase credits to offset emissions from those who have already reached their targets or are not subject to the regulations but have voluntarily reduced emissions.

Alberta's emissions-reduction strategy relies heavily on carbon capture and storage (CCS) and Enhanced Oil Recovery (EOR). The province plans to reduce 70% of its emissions through CCS. GHG reductions from substitution of a proportion of the bitumen binder used in conventional hot mix asphalt for a sulphur product are also quantified.

British Columbia

Introduced in 2008, the tax on fossil fuels now stands at $30/tonne of CO_2 eq. and applies to gasoline, diesel, natural gas, heating fuel, propane and coal — and to peat and tires when used to produce energy. Revenue raised, which was $1.21 billion in fiscal year 2013/14, goes toward lowering other taxes. The tax covers about 70 per cent of British

Columbia (B.C.)'s emissions, and it's estimated it will reduce emissions by about three million tonnes annually by 2020.

B.C. is a member of the Western Climate Initiative under which several U.S. states and four Canadian provinces have agreed to establish a regional cap-and-trade program and set a regional emissions-reduction target of 15 per cent below 2005 levels by 2020. The British Columbia Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) includes both a minimum requirement for renewable content in petrol (5%) and diesel (4%) fuels and a carbon reduction requirement for these fuels by targeting a 10% reduction by 2020. A system of credit transactions for both renewable fuel supply and low carbon fuel supply between oil suppliers has been established under the auspices of the regulatory authority. In practice the oil companies were able to allocate on paper their lower Carbon Intensity (CI) fuel to the British Columbia market, while allocating all their higher CI fuels to other markets. This fact led the authorities to revise the RLCFRR towards considering single reportable petrol and diesel CI.

3 POTENTIAL AND INCENTIVES OF UPSTREAM EMISSION REDUCTION

3.1 Introduction to the FQD

The **Fuel Quality Directive (FQD)** sets a target of 6% (Article 7a) reduction of GHG emissions from road transport. Moreover, the FQD (Article 7a(1)) obliges suppliers to report from 2011 information on, inter alia, the GHG intensity of the fuel they have supplied to authorities designated by the Member States. Furthermore the Commission is empowered to adopt Implementing Measures concerning the method for calculation and the mechanism to monitor and reduce GHG emissions of fuels used in road transport. To this direction a recent Council Directive (2015/652) on **"laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC of the European Parliament and of the Council relating to the quality of petrol and diesel fuels"** was launched to support implementation of Article 7a of the FQD.

The main features of the recent Directive regarding the method for calculating greenhouse gas emissions of fuels are based on average default values to represent the **GHG intensity per fuel** and on harmonized **annual reporting by suppliers to MS** and MS to the Commission. In other words the Directive assigns all suppliers a single, EU-wide average carbon emissions intensity for each oil and gas form supplied each year, regardless of the great spread of GHG emissions of particular fuel feedstocks and production pathways associated with individual suppliers. In addition, Article 7a of the Fuel Quality Directive (FQD) allows for the **opportunity of suppliers to use 'Upstream Emissions Reductions' (UERs) to comply with targets** in order to reduce the carbon intensity of their transport fuel supply.

Therefore the FQD does not include an explicit mechanism to favour the usage of conventional oil/gas over high carbon emitting unconventional oils/gases, even of some high emitting conventional oils/gases over other less emitting ones. Moreover, despite the fact that flaring and venting comprise by far the largest part of GHG emissions compared to other sources throughout the oil and gas supply chain, the FQD does not clearly focus on these two emitting processes.

3.2 Incentives and policies for Upstream Emission Reduction

There are many policy tools available to help induce greenhouse gas emissions reductions, including voluntary actions and agreements, financial incentives and subsidies and information instruments.

Market-based approaches are thought to be most effective because they signal that GHG emissions have a monetary value, stimulating actions that will lead emitters to reduce their emissions. There are different ways of pricing carbon that can be used in combination with other mechanisms, such as restrictive regulations. While it is acknowledged that putting a price on carbon is an effective way to reduce emissions, the best market mechanisms or combination of mechanisms for pricing carbon is much more difficult to establish.

GHG emissions units can take the form of allowances or credits. Allowances are issued under cap-and-trade mechanisms, where the emissions of a country, a sector, or a group of installations are capped and allowances are issued and allocated to the country or entities in line with the cap; an example is the trading of Assigned Amount Units (AAUs). Emissions Trading Schemes (ETS) are a sub-form of cap-and- trade mechanisms, where the allowances are allocated to individual installations or companies; examples include the EU ETS or the California ETS. Credits are units that are issued under a crediting scheme for emission reductions achieved against a crediting baseline; examples include the CDM, JI, the bilateral Joint Crediting Mechanism (JCM) established by Japan, or voluntary offsetting schemes (e.g. Climate Action Reserve, Verified Carbon Standard, Gold Standard Foundation, etc.).

Mechanisms can be established under international, bilateral, or domestic governance. Under international governance the issuance of units is governed by an international body according to internationally agreed rules, such as the CDM under the Kyoto Protocol. Under domestic governance, the issuance of units is governed by one Party; while under bilateral governance two (or more) Parties are involved in the issuance, transfer and use of units. Examples are domestic or regional ETS, such as the EU ETS and the California ETS, or the JCM established by Japan.

Finally, when referring to mitigation pledges, we mean pledges or commitments by Parties made under the UNFCCC, including its protocols, amendments and decisions, that express a limit on GHG emissions for an economy or a sector of an economy. Mitigation pledges can vary with regard to their scope and coverage and their legally binding status. Examples of mitigation pledges are commitments under the Kyoto Protocol or the economy-wide mitigation pledges made under the Cancun Agreements[18].

[18] Addressing the risk of double counting emission reductions under the UNFCCC, Stockholm Environment Institute, 2014

3.2.1 Cap-and Trade Systems

A cap-and-trade system is a regulatory program under which a government sets a cap on the quantity of GHG emissions, distributes permits for allowable emissions that add up to the cap, and enables firms to buy and sell the permits after the initial distribution. Regulated sources must pay allowances at the end of a given period equal to their emissions. The price for emission allowances (the carbon price) is determined by supply and demand for allowances in an emissions trading market.

Cap-and-trade systems can be focussed either on "upstream" or on "downstream" facilities. An upstream cap-and-trade system applies to fuel suppliers and requires them to surrender allowances equivalent to the carbon content of fossil fuels they distribute. Such a system would cover almost all energy-related emissions. This option has the advantage of being relatively simple, and it covers the entire economy. Analyses have shown that it would be environmentally efficient, minimize costs to the economy, be manageable administratively, and link easily to EU and international offset programs.

A downstream cap-and-trade program applies to sources of GHG emissions and requires them to pay allowances equal to their emissions. An all-source-downstream-cap and trade system would imply the regulation of millions of individual GHG sources, including cars and homes. Because of the difficulty in monitoring emissions from small sources, as well as the potential transaction costs involved with emissions trading from small sources, such a system could most effectively apply to a subset of sources consisting of large emitters.

If a company does not have sufficient allowances to cover its emissions or if reducing actual emissions or purchasing credits within the cap-and-trade system is relatively expensive, the company may be permitted to supplement its allowances by purchasing emission reductions outside of the cap-and-trade system. This may include "carbon offsets" or credits associated with other emission reduction systems like those provided through the Kyoto Protocol.

Carbon offsets are certified emission reductions produced by individuals and businesses not regulated under the cap-and-trade system that regulated facilities can purchase. Carbon offsets can include such projects as those that produce renewable energy, energy efficiency, reforestation and GHG emission reductions resulting from changes in agricultural practices.

The Kyoto Protocol includes systems that allow the purchase of credits internationally. This will be done through one of the Kyoto mechanisms. The two mechanisms are designed to create credits that then can be traded, if a country or industry so chooses:

- The Clean Development Mechanism (CDM) allows developed countries to gain credits for projects with verifiable emission reductions in developing countries; and
- The Joint Implementation (JI) mechanism allows developed countries to gain credit through projects in another developed country, or in a country in transition to a market economy.

These credits may also be allowed to apply to a facility's target within a domestic cap-and-trade system. The price of international credits and carbon offsets, as well as the quantity of them that would be allowed for use against targets, will influence the price of credits within the cap-and-trade system. The credibility of the credits would influence the effectiveness of the scheme.

3.2.2 Emission (Carbon) Tax

A "carbon tax" or a tax on GHG emissions imposes a direct fee (the carbon price) on emission sources based on the amount of GHG they emit, but does not set a limit on GHG emissions. In a manner similar to cap-and-trade options, the tax could be imposed upstream or downstream. It could require importers, producers and distributors of fossil fuels to pay a fixed fee on the CO_2 contained in fuel sold and/or it could require emitters to pay based on their actual emissions.

In order to make a tax more politically acceptable, revenues generated by carbon taxes are typically recycled back to emitters and the general public, who may be paying higher prices for goods and services affected by the taxes. Revenue recycling could take many forms, including compensating adversely impacted firms and segments of society, proportionally returning revenue based on tax paid, reducing other labour or capital taxes, or investing in technology and innovation.

An emission tax program, unlike a cap-and-trade scheme, does not guarantee that a given emissions reduction target will be met, because emitters may choose either to pay the tax or to reduce emissions. As a result, the level of the tax will likely have to be adjusted over time to meet a given emission target. This system does, however, provide price certainty, because the tax level is set before the policy is implemented.

Analyses have shown that an emission tax is more likely to allow for adoption of the cheapest mitigation strategies, as well as easier administration, than a cap-and-trade scheme. How policy-makers distributed revenues from the tax would determine the economic impact and effectiveness of the tax. However, political acceptability is likely to be a major obstacle, since new taxes and fuel price increases would garner negative reaction. An emission tax may be more politically attractive as part of a larger tax reform program.

Generally speaking, existing carbon taxes are primarily aimed at fossil fuel use and related emissions, and have been mostly applied to the household sector and services sector. Industry typically benefits from various exemptions because of concerns about international competition. British Columbia's carbon tax is somewhat different in that it is broad in scope and there are few exemptions.

Although some correlations have been found between carbon taxes and greenhouse gas reductions, it is difficult to specifically attribute emission reductions to a carbon tax for a number of reasons, including:

- the countries that have implemented forms of carbon taxation have done so as one part of a suite of other programs aimed at reducing emissions, many of which could have cross-sectoral impacts on emissions;
- no country has put in place a true economy-wide carbon tax, choosing rather to target some areas while exempting others, often exempting the sectors where the major effort is required for emission reductions; and
- carbon tax regimes that do exist have generally been weak as a result of worries about competitiveness, given that other countries have not put such taxes in place.

3.2.3 Direct Regulations

Economy-wide regulatory mechanisms to force GHG emission reductions have never been seriously considered without a trading mechanism (cap-and-trade). They could, however, be used for parts of the economy that may not respond well to a price signal. There may be no response because:

- market failures and other barriers may reduce the responsiveness of certain sectors to changes in emission costs – particularly in the transportation and building sectors and some consumer markets, such as those for vehicles, houses and appliances; and
- emissions from some sectors of the economy, including agriculture, forestry, and waste management, may not be covered by the broad price signal.

Improving product efficiency standards yields limited results, because the incentive to reduce the use of inefficient products and to replace such products with more efficient ones is weak; indeed, the incentives may lead to greater use of energy-consuming products, since energy savings may allow consumers to buy more of these products, including some with elevated consumption levels. Energy use reduction through efficiency also effectively increases supply relative to demand, which could decrease energy prices, spurring greater demand.

There is a consensus that direct regulatory instruments would not lead to large reductions in GHG emissions but could be used as complementary policy tools to a market-based approach like an emission tax or a cap-and-trade scheme. For example, only by putting a significant price on carbon emissions would carbon capture and storage become economically attractive[19].

3.2.4 Current practice

There is general agreement that putting **a price on carbon through an emissions tax and/or a cap-and-trade approach is the most effective way to achieve GHG emission reductions**. Taxes are generally seen as the most cost effective method, but they are not

[19] Policy Options to reduce Greenhouse Gas Emissions, Frédéric Forge, Tim Williams, Science and Technology Division, Parliament of Canada

easy to couple with reduction targets and are politically very difficult to be implemented. Cap-and-trade systems are more complex to be implemented, must be very carefully planned (the compliance mechanisms and the volume and distribution of permits, in particular, must be well-thought-out) and do not provide cost assurance. In addition, companies may pass on to consumers the costs incurred by a cap-and-trade system in a way that is less transparent than a tax. Scandinavian countries pioneered the use of carbon taxes in the early 1990s. While a few other jurisdictions, most recently British Columbia, have since followed suit, carbon taxes have not been widely adopted. Rather, the cap-and-trade system has emerged as the internationally preferred market mechanism for mitigating GHG emissions. Despite some initial problems, the system is growing both in scope and in importance. Various legislative initiatives in the United States also indicate that a cap-and-trade scheme is likely to become the dominant market mechanism for mitigating GHG emissions in the United States, particularly given the political difficulties involved with introducing a new tax. In Canada, authorities claim that of the options available, the "most effective and efficient policy that would result in deep GHG emission reductions is a market-based policy, such as an emissions tax, a cap-and-trade system, or a combination of the two. This core policy then needs to be complemented by other regulatory policies, to force emission reductions from parts of the economy that do not respond to a price policy." However, it is difficult to establish the exact mix of pricing policies which would be most effective and politically acceptable.

3.3 The EU legislative context

3.3.1 Emission Intensity Standards and the FQD

The FQD aims to create a system that sets tough standards for emissions intensity but does not explicitly favour the use of comparatively cleaner fuels. It does not include an explicit mechanism to favour the usage of conventional oil over high-GHG unconventional oils and lacks a mechanism to distinguish various conventional oils, which display a surprisingly wide spread of emissions intensities, in some cases even higher than those of many unconventional oils. Operational factors such as the flaring or venting of methane are the key elements driving the emissions intensity of GHG intensive conventional oils. Yet these factors are poorly understood and characterized in current policy.[20]

Similar systems as the FQD, manipulating emission intensity standards, combined with offset credits mechanisms (such as UER credits) have already been implemented in other cases. Specifically, the first low-carbon fuel standard mandate in the world was enacted by California in 2007, with specific eligibility criteria defined by the California Air Resources Board (CARB) in April 2009 but taking effect in January 2011. Similar legislation

[20] Emission intensity standards and the push for cleaner fuels, David Livingston, December 2014

was approved in British Columbia in April 2008. The cases of California and British Columbia are discussed further on.

Emissions Intensity Standards

Emissions intensity standards seek to reduce the GHG intensity of transport fuels and foster alternative fuels without necessarily establishing a cap on the total volume of transport fuel emissions. They instead set an **emissions intensity target for the lifecycle greenhouse gas emissions per unit of transport fuel energy** supplied in a given market. Targets are usually expressed in terms of grams of carbon dioxide equivalent per mega-joule of energy supplied (gCO_2e/MJ). The targets are often articulated as a percentage reduction against the emissions intensity of a baseline year. These policies then assign default emissions intensity values to various fuels depending on their particular production pathway—that is, what feedstock they were produced from and the process used to produce them.

These standards are hybrid instruments that neither explicitly price carbon emissions (as with a carbon tax) nor explicitly limit the total amount of permissible emissions (as with a cap-and-trade system). Instead, they combine an implicit carbon tax with an implicit output subsidy.

The implicit tax derives from the fact that by employing different default lifecycle emission values for different fuel pathways, pathways with higher emission values will see their prices drop in the fuel market. Similarly, pathways with lower emission values will enjoy market premiums.

The implicit production subsidy derives from the fact that, because the policy focuses on the intensity of the fuel mix, rather than setting ceilings or floors on the quantity of various fuels sold, it could encourage the consumption of more, not less, total fuel than would otherwise be consumed in order to comply with the standard. As more fossil fuels are sold, more alternative fuel sales become necessary to dilute the carbon intensity of the overall mix, driving up the volume of total fuel sales in a given period.

3.3.2 The Renewable Energy Directive

The European Union is promoting the use of renewable energy in transport with an objective of 10% renewable energy in transport by 2020 as set out by the **Renewable Energy Directive (RED)**. The use of sustainable biofuels is one way of meeting these targets. Road transport depends almost entirely on oil as a fuel at present and corresponding greenhouse gas emissions continue to increase at a high rate. Transport is the only sector where energy consumption is not expected to decrease over the next two decades, if economic development follows business as usual scenarios. At present the main alternative to fossil based fuels in road transport are biofuels, whether liquid or gaseous.

The RED required Member States to submit by June 2010 National Renewable Energy Action Plans setting out inter alia the contribution expected of each renewable energy technology to meet the 2020 targets, including in the transport sector. According to the National Renewable Energy Action Plans, Member States collectively intended to slightly over-achieve the 10% target. Their intention was to use about 8.5% of first generation biofuels, 1% of second generation biofuels and 1% of renewable electricity, most of the latter in railways rather than in cars. In total this adds up to approximately 10.5% renewable energy in transport; with the different weight factors that the Directive applies to second generation biofuels and renewable electricity used in cars it would be counting as approximately 11.5%. However, this target will most probably not be achieved, as the recent EC Directive 1513/2015, issued on 9 September 2015, states that the share of energy from first generation biofuels shall be no more than 7 % of the final consumption of energy in transport in the Member States in 2020. Therefore, an overachievement of the RED target by Member States is nowadays highly unlikely.

According to reliable sources[21], the 10% share of renewable energy in transport targeted by **the RED for Member States is expected to contribute approximately 4%** in the reduction of GHG emissions of the FQD target. It is, therefore, expected that **the remaining 2% will be covered by the use of UER** units, as provided in the Implementing Measure.

3.4 The case of California

California is a pioneer in establishing a system of calculating and reporting GHG emissions setting as objective the reduction of well-to-tank Carbon Intensity (CI) of fuels used in transport. The relevant regulation LCFS (California Low Carbon Fuel Standard) requires fuel providers to reduce the carbon intensity of transportation fuels by 10% by 2020 compared to 2010. Since 2011 and after long discussions and implementation of first efforts to monitor and control the CI of oil products, the California Air Resources Board (CARB) decided the adoption of the California Average Approach. By that system the average emissions intensity of the California crude basket is to be calculated using OPGEE, an emissions modelling tool developed by CARB, taking into consideration the CI of all crudes supplied to California in a year. In case the average CI of the California crude basket was higher than the baseline year CI, then an additional “California average incremental deficit” in GHG emissions is estimated. The deficit has to be covered by all oil suppliers by obtaining as offset the proper CA-LCFS credits. In case the California crude basket evolved to a lower average CI than in the baseline year, then the fuel suppliers were not benefited with any specific credit. A fuel provider for a list of predetermined alternative fuels (electricity, biogas CNG, biogas LNG, fossil CNG derived from North American sources, etc.) with low CI may generate LCFS credits for that fuels only by electing to opt into the LCFS.

[21] UK Department of Transport

Under this system the allocation of the cost of the poor performance of one year is implemented to all oil suppliers either achieving the CI reduction target individually or not. Therefore the increased costs of poor performance will be spread across the whole oil industry and evidently the California Average Approach will be particularly ineffective in preventing increase in fossil fuel GHG emissions. However, there is an incentive to support, through the offset system, low carbon fuels, which will increase penetration in the market and thus contribute to the decrease of the overall CI of the fuels used.

3.5 The British Columbia case

The British Columbia Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) includes both a minimum requirement for renewable content in petrol (5%) and diesel (4%) fuels and a carbon reduction requirement for these fuels by targeting a 10% reduction by 2020. A system of credit transactions for both renewable fuel supply and low carbon fuel supply between oil suppliers has been established under the auspices of the regulatory authority.

There is a methodology of RLCFRR allowing fuel CI to be calculated in one of three ways. The default CI values for fossil fuels are reported and publicized and the biofuel suppliers are allowed to report the default value for their corresponding fossil fuel rather than having feedstock specific defaults. Alternatively by the use of the GHGenius model specific CI values for fuels might be estimated, or the regulatory authority might, at its discretion, allow other approaches to be used.

Currently there is no incentive for a supplier of a higher than the default CI diesel or petrol to calculate a fuel specific carbon intensity value, thus diesel from tar sands would be not reported at its actual CI, but rather at the lower CI of the default value. On the contrary, for fossil fuels of CI below the defaults, there is an incentive to report a more accurate CI. There is also an incentive to reduce CI for a refining or production process in case the produced fuel CI becomes better than the default, or improves further the existing lower than the default CI. For some big oil suppliers operating in several jurisdictions and using various crudes, the RLCFRR system allows them the situation of fuel shuffling rather than actual CI reduction. In practice the oil companies were able to allocate on paper their lower carbon intensity fuel to the British Columbia market, while allocating all their higher CI fuels to other markets. This fact led the authorities to revise the RLCFRR towards considering single reportable petrol and diesel CI.

The RLCFRR complements other provincial and federal GHG policies. The federal vehicle emissions regulations are increasing the energy efficiency of the transportation sector, while the carbon tax is affecting driver behavior and vehicle purchases. Meanwhile, the RLCFRR will ensure that each unit of energy that is consumed for transportation results in fewer GHG emissions from a full lifecycle perspective, including production, transportation and consumption of the fuels. Once the RLCFRR is well established, the carbon intensity of fuels can be further reduced to match the need for GHG reductions and create the demand for more low carbon fuels. The policy creates a larger market for biofuels and other low carbon fuels. The combined market creates larger reward opportunities, which spurs larger investments in new technologies and supply chains.

3.6 Emission offset mechanisms

Directive 2015/652 mentions that "*In order to facilitate the claiming of UERs by suppliers, the use of various emission schemes should be allowed for calculating and certifying emission reductions*". Since the potential of UER from fossil fuel feedstock produced within Europe is relatively small, it is most likely that UERs will be generated outside the EU. Therefore, UERs are subject to be demonstrated through the generation of credits under voluntary schemes and internationally recognised mechanisms.

The most common offsetting programmes which could be used to generate UER credits are the UN's Clean Development Mechanism (CDM) and Joint Implementation (JI). CDM is the offsetting mechanism under the Kyoto protocol applied in projects in developing countries, whereas JI concerns developed countries (Annex 1). Among registered JI projects, all those that concern flaring reduction are located in Russia.

There are three CDM methodologies that could generate eligible projects for UER:

- Recovery and utilisation of gas from oil fields that would otherwise be flared or vented (AM0009)
- Flare (or vent) reduction and utilisation of gas from oil wells as a feedstock (AM0037)
- Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users (AM0077)

3.7 The European Emissions Trading Scheme

The European Emissions Trading System (EU ETS) could be expanded in order to cover the scope of UER accounting.

The EU ETS follows the cap-and-trade approach. Within the EU ETS, certain emission-intensive industrial installations and aviation within the EU-28 and the EEA-EFTA states (Iceland, Lichtenstein and Norway) are obliged to acquire emission allowances in order to emit GHGs. The industrial sectors covered comprise installations for supplying electricity and heat, mineral processing, metal production and processing, paper manufacture, chemicals and installations for carbon capture and storage (CCS). Since 2013, aviation involving all flights between two EU-airports has also been included in the EU ETS. Emissions of carbon dioxide (CO_2), nitrous oxide (N_2O) and perfluorocarbons (PFCs) are subject to approval. Since 2008, Member States have been allowed to include additional sectors in the EU ETS following approval by the European Commission. Member States may exclude installations from the EU ETS which annually emit less than 25,000 tons of CO_2[22].

The EU ETS currently represents a "downstream" emissions trading system: it is the consumers of fossil fuel, i.e. the emitters of GHGs, who have to acquire allowances. In other words, allowances have to be held not by the suppliers of fossil fuel at the top of the supply chain, but by installation operators or airlines at the bottom that actually emit the GHGs. Its efficiency could be enhanced by extending it to other sectors with high GHG emission levels, such as the upstream oil and gas sector. However, as mentioned before, the European upstream oil and gas sector does not have a significant potential for emission reduction, thus the EU ETS would not contribute to a considerable extent to the generation of UERs.

[22] Art. 2, 3a-3g, 4 and 24 Directive 2003/87/EC of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.

EU Stakeholders' views on GHG emissions reporting and assessment

In the course of the "Study on actual GHG data for diesel, petrol, kerosene and natural gas", a questionnaire on GHG emissions reporting and the FQD requirements was distributed to a large number of stakeholders. The replies of more than 100 stakeholders coming mainly from the oil & gas and the biofuels industries have been processed by EXERGIA. The stakeholders' views can provide a rough estimation of the motivation of interested parties to analyse the GHG emissions related to their activities. Since the formulation of EU policies usually follows an intensive consultation process with stakeholders, it is interesting to make a brief analysis of their opinions on the matter. Key findings of this survey include the following:

- Most stakeholders are not satisfied with the way GHG intensities of fossil fuels are calculated. This opinion is even supported by stakeholders of the oil and gas sector.
- The reliability of reported GHG emissions data is questioned by the majority of respondents.
- The biofuels sector requests more transparency in the assessment of GHG emissions of fossil fuels, as well as equal treatment of fossil fuels with bio fuels in terms of calculating and reporting the GHG intensity of different pathways.
- A number of stakeholders state that it is difficult to manage a GHG intensity assessment system that traces fuel pathways back to their country of origin, however it would allow fairer comparison to biofuels based on equivalent system boundaries.
- There are opinions that favour the enforcement of carbon tax and penalties to oil and gas companies who fail to comply with the legislation in terms of GHG intensity standards as well as emissions reporting to the authorities. At the same time, it is suggested that low GHG intensities should be rewarded.
- Some stakeholders suggest the use of direct measurement techniques for GHG emissions from fuels pathways.

The survey was carried out in the spring of 2015, prior to the announcement of the FQD Implementing Measure (Council Directive 2015/652).

4 ASSESSMENT OF UER SUBJECT TO BE ACCOUNTED FOR UNDER THE FQD

4.1 UER reporting and certification mechanisms

Four possible emission-reduction certification and reporting mechanisms that could have been implemented so as to allow mainly flaring and venting reduction projects to be counted under the UER were proposed by the European Commission prior to the adoption of the Directive 2015/652/EC. These mechanisms were thoroughly analysed and described by ICCT in the relevant Study that was assigned by DG CLIMA[23]. In brief the mechanisms assessed are presented below:

- According to **Option 1, the so called "ETS-CDM option",** credits from the United Nations' Clean Development Mechanism (CDM) and Joint Implementation (JI) programs could be eligible for compliance under the FQD through the existing Union registry that tracks credits used under EU ETS. FQD-eligible CDM credits in the EU-centralized registry could be used for compliance under FQD. The current EU ETS transaction system for credits is an already well-established mechanism that includes multiple checks between the point of issuance of credits and their use for compliance.
- According to **Option 2, "the standalone CDM option"** CDM and JI credits could be eligible through a standalone registry. FQD-eligible credits could be transferred from national CDM registries to a stand-alone registry. This role could be assigned to the European Environmental Agency (EEA). This option would require the creation of this centralized registry and the appointment of an administrator. Operators must be allowed to set up accounts at this registry that will enable them to transfer and retire FQD-eligible credits.
- **Option 3** prescribing the development of a framework for crediting venting and flaring reduction projects specifically for the purpose of compliance under the FQD. The third option was further distinguished in two sub-options:
  - The first sub-option **(Option 3a, 'the prescriptive option')** envisaged a detailed and relatively prescriptive framework for crediting UERs. Such a framework could in principle be required at the European level by Commission action, but could also be implemented by a Member State as a

[23] The reduction of upstream GHG emissions from flaring and venting, Report by the International Council on Clean Transportation to the European Commission Directorate-General for Climate Action, 2014

national interpretation of the option to credit Upstream Emissions Reductions (UERs) or through a voluntary scheme with the intention of generating credits to feed into Member State implementations.

- The second **sub-option (Option 3b, 'the Implementing Measure requirements')** outlined how the requirements for UER reporting contained in the Implementing Measure for FQD Article 7a are to be implemented at the Member State level.

Eventually, Option 3b prevailed and was incorporated in Directive 2015/652/EC.

4.2 UER project eligibility under FQD Implementing Measure requirements

The Implementing Measure requirements that were eventually adopted in the Directive prescribe that eligible projects are not explicitly limited to those reducing venting and flaring emissions, and could potentially include other types of UER projects. More specifically, the eligibility criteria of the Directive (Annex I, part 1), as well as a brief analysis on controversial eligibility aspects are presented in Table 4-1.

Table 4-1 UER eligibility criteria in the context of Directive 2015/652/EC

Eligibility criterion	Directive 2015/652 phrasing	Interpretation
Type of eligible facilities	*UERs shall only be applied to the upstream emission's part of the average default values for petrol, diesel, CNG or LPG.*	The language used in the Directive allows for the eligibility of projects at **natural gas extraction sites** even though the emission reduction potential compared to oil fields is significantly lower, since there are already natural gas transport facilities and there is an absolute economic incentive to utilize gas. In addition, natural gas use in the EU transport sector is currently very limited and is not expected to rise significantly in the following years. Furthermore, the Directive allows for the eligibility of **projects beyond venting and flaring**. For instance, fuel switching from a fuel with carbon intensity to fuel with lower carbon intensity could be considered as creditable with appropriate argumentation and reporting.
Types of		In cases where gas-lift gas is necessary in order to

Eligibility criterion	Directive 2015/652 phrasing	Interpretation
associated gas		increase well pressure (EOR), associated gas from the same oil well is compressed and effectively reinjected as gas-lift gas. In some cases where a high-pressure gas field is located nearby, operators import this gas to use as gas-lift gas in the oil well, because it is less expensive than compressing and recycling associated gas. In cases where associated gas from the local oil well or pressurized gas-lift gas is imported from independent gas fields, it is eligible for crediting if that gas was previously being flared but can be captured by the project.
Transport to the market		There is no restriction related to the way that recovered gas is transported to market. This includes transport by pipeline, trailers, trucks, carriers, and CNG mobile units. The gas may be processed into dry gas, LPG, etc. or compressed into CNG before transport (although in such cases some additional monitoring and reporting is required).
Flaring efficiency	*UERs should be estimated and validated in accordance with principles and standards identified in International Standards, and in particular ISO 14064, ISO 14065 and ISO 14066.*	ISO 14064-2 does not directly prohibit projects that contribute to the improvement of flaring efficiency, which could in theory be eligible. Certainly, the ISO allows for "appropriate GWPs" to be used in the assessment of emissions reductions (ISO 14064-2 article 5.8). This would support the possibility of crediting methane destruction based on the difference between the GWP of the combusted methane and that of the resultant CO_2. Although there is no direct restriction on the eligibility of emissions savings delivered through improved flare efficiency, there are requirements for treatment of accuracy and uncertainty that might limit the possibility to credit such projects. Providing UER credits to such projects includes large uncertainty due to measurement difficulties and inaccuracies. As an adverse effect, it could even increase emissions as operators would have the incentive to flare inefficiently until the UER project realization. Therefore, flaring efficiency improvement projects are most probably not going to be counted

Eligibility criterion	Directive 2015/652 phrasing	Interpretation
		towards the acquisition of UER credits.
Venting and fugitive emissions eligibility		Venting and fugitive emissions are treated with large variations among different emission reduction schemes with respect to crediting. In the CDM/JI venting reduction projects do not receive additional credits related to the higher global warming potential of methane compared to carbon dioxide and it is assumed that methane is flared. In contrast, the Directive 2015/652 allows the crediting of methane destruction (as the Alberta Offset System), even though some attention is required with respect to the interpretation of the ISO 14064.
Prior flaring, mode of transport, end use	-	The Directive poses no restrictions with respect to whether flaring or venting occurred before project commencement, modes of transport, end uses of the gas, the types of gas to be eligible (i.e. associated or gas or gas lift).
Geographical location of projects	*UERs originating from any country may be counted as a reduction in greenhouse gas emissions against fuels from any feedstock source supplied by any supplier.*	The Directive sets no geographical restrictions on the countries in which UERs may take place, contrary to the CDM mechanism. Projects from all countries and fields will be eligible under the FQD and its Implementing Measure.
Completion date	*UERs shall only be counted if they are associated with projects that have started after 1 January*	Existing projects (i.e. those that have been completed prior to 1 January 2011) are not eligible to receive UER credits as they do not respect the rule of additionality. One issue that could create controversy is the fact that certain projects could be proven to be financially not viable under the current value of CERs and thus financial support could be required. Nonetheless, the specific issue requires thorough investigation and strict

Eligibility criterion	Directive 2015/652 phrasing	Interpretation
	2011.	regulation.
Additionality	*It is not necessary to prove that UERs would not have taken place without the reporting requirement set out in Article 7a of Directive 98/70/EC;*	The Implementing Measure requirement excludes the principle of additionality (i.e. the requirement to prove that reductions would not have taken place without the additional incentives of the Fuel Quality Directive). Nonetheless, ISO standard 14064 deals with the concept of additionality in a way that there is some controversy. More specifically, emission reductions may only be accounted towards compliance with the FQD if the project generating them can be demonstrated to be additional in the context of ISO 14064-2. This implies that the project developer should prove a case to argue that the project is additional, in particular with regard to any legal obligations on the company, and to the question of whether the project would have occurred anyway for commercial reasons regardless of emissions concerns.

4.3 Eligible CDM/JI projects under FQD Implementing Measure

Various CDM projects could be eligible for compliance under the FQD. As discussed, there are three approved CDM methodologies to credit displacement of gas production through reductions in venting and flaring of gas from oil production: AM0009, AM0037, and AM0077. These are presented in Table 4-2.

Table 4-2 Comparison between approved CDM methodologies to credit reductions in venting and flaring of gas from oil production (source: ICCT)

Methodo -logy	Prior Venting/ Flaring Required	Eligible Sources of gas	Eligible Transport Options	Eligible end uses	Leakage in calcs	Fugitives in calcs
AM0009	None (but oil wells must be in	Associated gas + lift	Pipeline or by trailer,	Not specified;	Required	Not included

Methodo -logy	Prior Venting/ Flaring Required	Eligible Sources of gas	Eligible Transport Options	Eligible end uses	Leakage in calcs	Fugitives in calcs
	operation)	gas	truck, carriers as CNG	partial use on site allowed		
AM0037	3 years	Associated gas	Not specified	Gas used as feedstock and partially as energy source in chemical process	Not included	Required
AM0077	3 years	Associated gas	CNG mobile units or pipeline	Heat (in the case of CNG mobile unit transport)	Required	Not included

According to the Non-profit Association "Transport and Environment[24]" 13 projects that qualify with the FQD's requirements are illustrated in Table 4-3, including one project located in a Least Developed Country (Angola). In total, these 13 projects have estimated annual emission reductions of more than 18 million tonnes CO2eq. The total upstream emission reductions from the flaring & venting project in Angola could accumulate up to 13.7 million tonnes of CO2eq per year for example, more than enough to meet the full 6% GHG intensity reduction target.

Table 4-3 Number of projects registered since 2011 and emission reductions according to host countries

Host country	Number of projects	Emission reductions (metric t CO2 e/ annum)
Angola	1	13,709,960

[24] The role of international offsets in the Fuel Quality Directive December 2014.

Host country	Number of projects	Emission reductions (metric t CO2 e/ annum)
Indonesia	3	386,799
China	2	359,635
India	1	65,811
Ghana	1	2.603,226
Nigeria	1	288,147
Oman	1	775,250
Papua New Guinea	1	57,438
Thailand	1	26,163
United Arab Emirates	1	109,142
TOTAL	**13**	**18,381,571**

Similarly JI projects can be eligible to prove compliance with the FQD. Out of all the registered JI projects, just 4 of them concentrate on associated gas utilisation, but all of these have been set up in Russia. These are presented in Table 4-4.

Table 4-4 Registered JI projects concerning associated gas utilisation

ITL project ID	Title	Host party	Last updated
RU1000200	Yety-Purovskoe Oil fi eld Associated gas recovery and Utilisation project	Russian Federation	15 Dec 10
RU1000229	Associated Petroleum Gas Recovery for the Kharampur oil fields of Rosneft	Russian Federation	09 Mar 11
RU1000230	Associated Gas Recovery Project for the Komsomolskoye Oil Field	Russian Federation	09 Mar 11
RU1000239	SNG gas gathering	Russian Federation	17 Mar 11

4.4 UER potential and abatement costs

Various studies have assessed investment and abatement costs for emissions reductions from flaring and venting. Each study has used different methodology and focused on different geographic areas and technologies. Table 4-5 lists only the CO2eq reduction potential that can be achieved at negative costs, (i.e. profits) as reported in the literature, for the oil sector only, while Table 4-6 reports the reduction potential and associated abatements costs for oil and gas sectors given the availability of carbon prices for credits generated from associated petroleum gas (APG) recovery.

Total carbon mitigation potential from economically profitable flaring and venting reduction projects **in the oil sector in EU-15, Canada, Nigeria, Russia and the US combined can be in the range of 127-143 MtCO2e per year**. It is to be noted that the magnitude of carbon abatement will increase if the price, APG can fetch in the market. increases. Moreover, as Table 4-6 indicates, additional reductions can be achieved if the projects can accrue revenues from selling carbon credits. At a credit price of $100/tonne CO2e, carbon mitigation can increase to 41.8 MtCO2e/yr in 2020 from projects in Libya, Nigeria, Iran/Yemen and Russia/Azerbaijan compared to 20 MtCO2e/yr in the absence of carbon prices. These countries/regions together account for 54% of total EU crude oil imports.

Table 4-5 Reported carbon mitigation potential at abatement cost for the oil sector

Study	Region/ Country	Project Type	Flaring/ venting	Reduction Potential (mtCO2e)/ year	Investment Cost (per tCO2e)	Abatement Cost (per tCO2e)
Ecofys, 2001	EU-15	Increased gas utilisation, maintenance, and improvements of compressors	emissions from associated gas, process vents and flares, engines, turbines, compressors and pumps, system upsets, and transmission and distribution activities.	0.6	€ 0-30 ($0-41.4)	€ -1 to -4 (-$1.4 to 5.5)
Johnson and Coderra, 2012	Alberta-CA	Collection, compression and pipeline	Flaring and venting	17-33		US $-40 to<0
PFC Energy,	Russia	Variety of projects from		70		

Study	Region/ Country	Project Type	Flaring/ venting	Reduction Potential (mtCO2e)/ year	Investment Cost (per tCO2e)	Abatement Cost (per tCO2e)
2007		electricity generation to a combination of gas processing plants and dry gas sales				
ICF, 2013	Russia/ Azerbaijan and Nigeria		Flaring fugitive and venting	20		<0
ICF, 2014	US-onshore oil		Fugitive and venting emission control	25.6	US $6.9	US $-5.7 to $-0.5
Total reduction potential from EU-15, Canada, Nigeria, Russia, and US from profitable projects				**127-143 MtCO2e**		

Table 4-6 Mitigation potential and costs for projects that are profitable with additional revenue through carbon prices

Study	Region/ Country	Project Type	Emissions type	Reduction Potential (mtCO2e)/ year	Investment Cost (per tCO2e)	Abatement Cost (per tCO2e)
Ecofys, 2001	EU-15		Emissions from associated gas, process vents and flares, engines, turbines, compressors and pumps, system upsets, and transmission and distribution activities.	25.4	N/A	$1.38-124.2
Ecofys, 2009	EU	(a) eliminating chronic leaks from pipelines, distribution facilities, etc. for natural gas, (b) eliminating chronic leaks from pipelines, distribution facilities, etc. for APG from oil production (c) reducing flaring emissions and		10.3	N/A	$2.89-14.9

Study	Region/ Country	Project Type	Emissions type	Reduction Potential (mtCO2e)/ year	Investment Cost (per tCO2e)	Abatement Cost (per tCO2e)
		(d) elimination of venting.				
GE Energy, 2010 (Project level assessment (not at country level)	Indonesia, Tanbun	Mini LPG plant, pipeline	flaring	0.4	\$30	\$15
	Qatar	Processing, NGL and pipeline	flaring	2.4	\$260	\$6.5
	Nigeria	Processing NGL and pipeline	flaring	2.6	\$302	\$7.5
	Nigeria	Processing NGL and pipeline	flaring	0.3	\$32	\$10
	China	Processing NGL and pipeline	flaring	0.3	\$30	\$11
ICF, 2013	Libya	Various options	Flaring fugitive and venting	1.8	-	Up to \$100
	Nigeria			11.1	-	
	Iran/Yemen			1.2	-	
	Russia/ Azerbaijan			26.6	-	
ICF, 2014	US-onshore oil and gas		Fugitive and venting emission control	116	18.9	Up to \$27.8
Johnson and Coderre, 2012	Alberta, Canada	Collection, compression and pipeline	Flaring and venting	28-46		Up to \$15
Carbon Limits, 2013	Russia, Kazak, Turkmenistan Azerbaijan		Flaring reductions in existing fields	31.5	US \$8 billion	N/A

4.5 Technical and economic potential of UER strategies

Flaring and venting emission reduction projects in most of the times entail costs to operator. This implies that the number of projects could be registered under the FQD emission reduction schemes, and thus the level of CO2 reduction that could be achieved, is heavily dependent on the value of emission reductions credits. Thus, in practice the theoretical emission reduction potential, which is estimated to be in the range of 127 – 140 MtCO2eq, is significantly lower. ICCT in order to conclude to a realistic UER potential in the context of the FQD, in its analysis, has used three levels of credit prices: a more modest price of $20 per ton of CO2e abatement, a moderate price of $50 per ton and a more aggressive price of $200 per ton CO2e. The higher price is consistent with typical estimates, given the cost of carbon abatement through the supply of biofuels, which are likely to be the primary alternative route to FQD compliance.

ICCT has assessed the annual emission savings potential[25] for the four options, by using and re-analysing[26] results from previous studies. It should be noted that there is considerable uncertainty related to the exact portfolio of projects that would be eligible under all options. This uncertainty is higher for the Implementing Measure requirements option as some issues with respect to project eligibility have to be elucidated and discretion is left on decided by Member States to decide which projects are eligible.

The results of the analysis by ICCT based on ICF and Energy Redefined primary work are illustrated in Table 4-7. The precise methodology and the underlying figures used for concluding to the specific results are described within the original studies. At a CO2 credit value of carbon price of $20/tCO2e, approximately 24 MtCO2e of annual UER could be delivered for a cumulative crediting period. This would amount to slightly less than half of the FQD target of a 6% reduction in the carbon intensity of European transport fuels. In the case that only 1 year is eventually accounted for as crediting period (2020), i.e. what the Implementing Measure requirement prescribes, the potential is significantly lower ranging from **2.30 million tonnes CO2eq (for $20/tCO2e carbon price) to 15.5 million tonnes CO2eq for (for $200/tCO2e carbon price). This is approximately between 5% and 30% of the 6% FQD target.**

Table 4-7 Total emissions savings that could be achieved with the prescriptive option for both 15-20 and 1 year crediting periods

	TOTAL SAVINGS (MILLION TONNES CO2)			TOTAL SAVINGS (MILLION $ GAS VALUE AT $2/MBTU)		
Credit price	$20/tCO_2e	$50/tCO_2e	$200/tCO_2e	$20/tCO_2e	$50/tCO_2e	$200/tCO_2e
15-20 year crediting period	23.57	37.44	42.94	555.0	881.7	1010.3

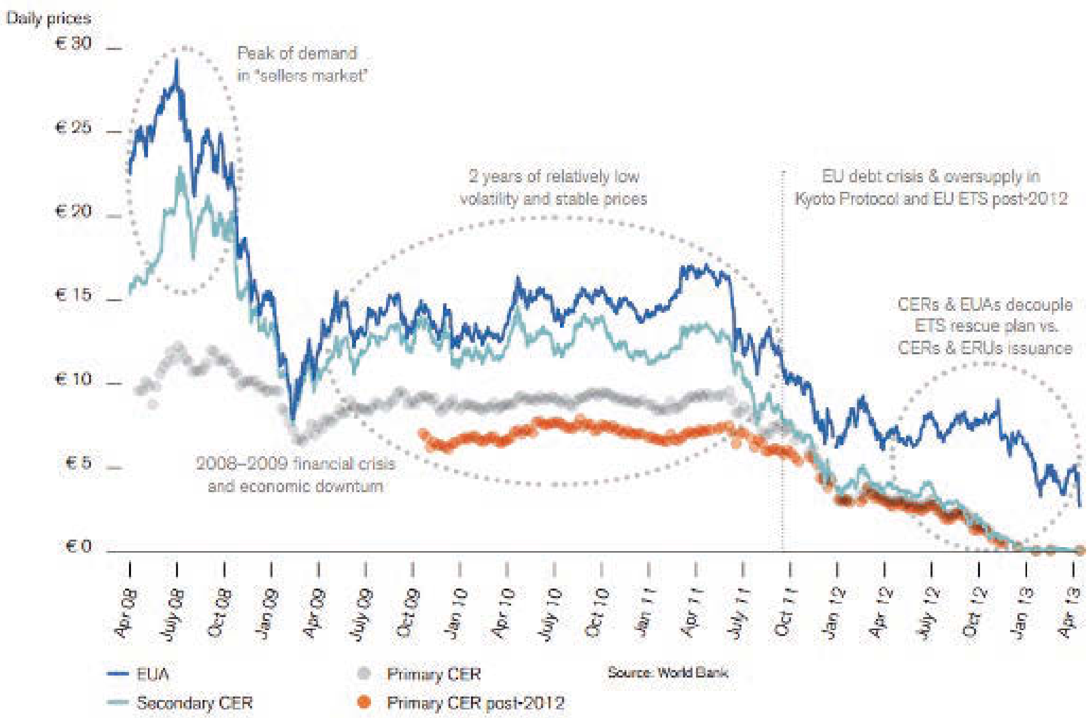
[25] The reduction of upstream Greeenhouse Gas Emissions from flaring and venting. Report by the International Council of Clean Transportation to the European Commission, DG for Climate Action, 2014.

[26] This represents the achievable emissions savings calculated by ICF plus the additional emissions savings that could be achieved as a result of more streamlined requirements under the prescriptive options

1 year crediting period	**2.30**	**2.58**	**15.55**	54.1	60.7	366.2

It is also worth assessing the correlation between total savings potential against carbon prices. Total savings potential generally follows a proportional trend against carbon prices (with a declining ratio however). ICCT in its study had modelled various potential for various carbon prices. The top credit price modeled, \$200/tCO2e, is high compared to current ETS and CER prices, which appear to have collapsed over the last years, as it is illustrated in Figure 4-1. On the other hand, this price is directly comparable to estimates of the carbon abatement costs of using biofuels (the primary alternative emissions reduction strategy under FQD). In its 2013 Impact Analysis for DG CLIMA of implementing options for the FQD, ICF estimated marginal abatement costs of biofuels in the EU as being at least €200/tCO2eq.

Figure 4-1 CDM carbon prices between 2008 and 2013 (source: the World Bank)



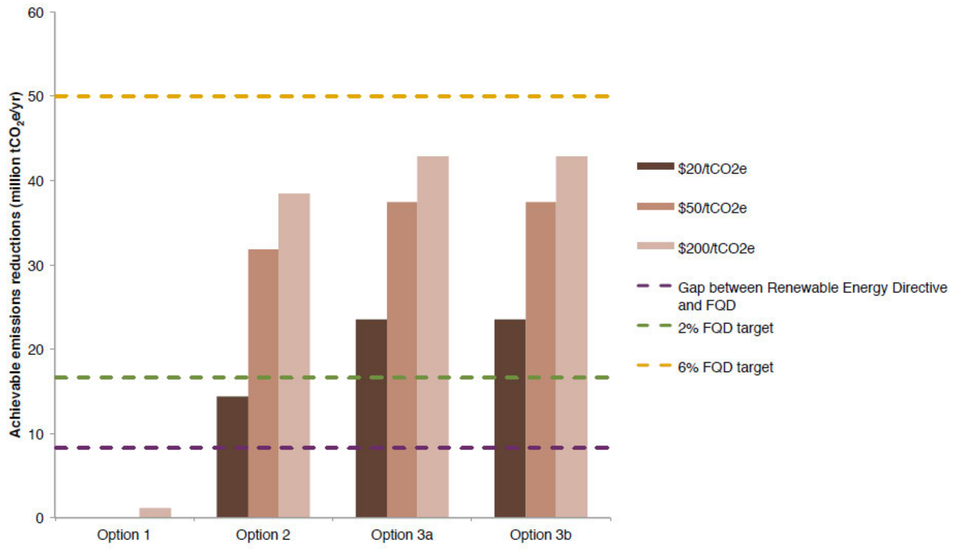
4.6 UER potential under the FQD

Figure 4-2 illustrates the potentially achievable emissions reductions under Options 1, 2, 3a and 3b according to three levels of relevance (i.e. targets) for the FQD. The 2% optional interim FQD target is presented by a dotted green line, while the full 6% target by a dotted yellow line.

The four options are compared also with the gap remaining to achieve the 6% FQD target. The latter target is set by considering that the 10% renewable energy target under the Renewable Energy Directive (RED) has already been achieved and is indicated by the dotted purple line.

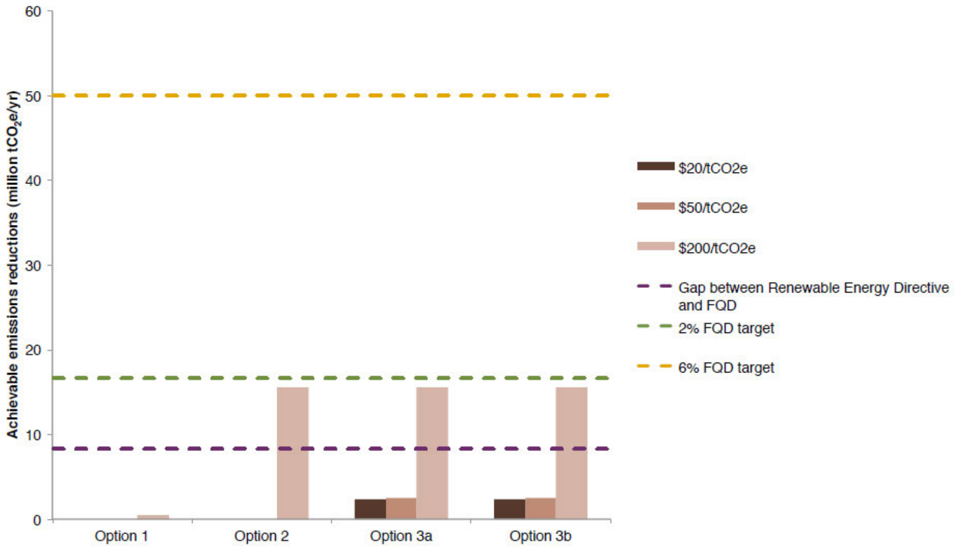
The potential for Options 2, 3a or 3b to deliver more than half of the emissions reductions required to meet the full 6% GHG intensity reduction target. At $50 per ton CO2e, Options 3b could supply 75% of this target. This conclusion is contingent upon an adequate credit price and adequate time (and market confidence) to initiate projects. Uncertainty or lack of confidence in upstream emission reduction credits could substantially reduce the actual level of investment.

Figure 4-2 Potential emissions reductions from venting and flaring under each option if credits are awarded over the project lifetime (source: ICCT based on Energy Redefined and ICF flaring report)



According to estimates and assuming a clear framework of incentives, UERs could be enough to cover the gap between the emissions reductions expected from RED compliance and the FQD target. Nonetheless, **currently the FQD only has a single year with a binding compliance target (2020),** which will significantly reduce the potential to deliver reductions compared to a system that delivered ongoing value.

Figure 4-3 Potential emissions reductions from venting and flaring under each option if credits are awarded in one year (2020) only (source: ICCT based on Energy Redefined and ICF flaring report).



Thus, if credit value was only considered for 2020, the potential would be greatly reduced according to the ICCT analysis and explained in the previous section. This is illustrated in

Figure 4-3 where UERs could only make a significant contribution to meeting the 6% carbon intensity reduction target under the FQD, if credit prices were high. Furthermore, it should be considered that this could significantly overestimate the potential, as according to ICCT the assessment assumes that investors would treat the carbon price as guaranteed, whereas in fact the willingness of oil field operators to invest could be limited. In practice, this problem could be largely resolved if Member States implement the optional interim GHG reduction targets, or if Member State implementations of the FQD do not expire in 2020.

4.6.1 FQD implementation in selected countries

Some countries such as Germany and the Czech Republic have introduced interim targets for GHG emission targets in the transport sector prior to 2020 moving beyond the requirements of the FQD which refers only to 2020.

Before 2015, the use of biofuels in the German transport sector was promoted by an obligation requiring the use of biofuels. This obligation was usually met by blending biofuels with fossil fuels. According to EU legislation, the share of renewables in the transport sector is to be increased to 10 % by 2020. In 2015, the so called GHG Reduction Quota was implemented in Germany. Now the mineral oil industry is obliged to reduce the GHG emissions stemming from their produce by 3,5 % in 2015 and 2016 respectively. From 2017 on the GHG reduction will have to amount to 4 % each year and will rise to 6% in 2020 where it is to remain. Apart from blending with biofuels there is also the possibility of Upstream Emissions Reductions, E-Mobility and Liquified Petrolem Gas (LPG) or Compressed Natural Gas (CNG) counting towards fulfillment.

The Czech Republic is another country that has introduced interim GHG emission reduction targets in the transport sector. The target set by the European Commission under the Directive 2009/28/EC is to reach 13 % share of energy from renewable sources against gross final energy consumption and a 10 % share of renewable energy sources in transport by 2020. The Czech Republic in general does not have significant problems in meeting its targets, although in 2010 they did not fulfil the target to replace 5.75 % of energy content of fossil fuels consumed in transportation with biofuels. Blending of biofuels with fossil fuels has been mandatory in the Czech Republic since September 1, 2007. The Czech Republic transposed the European Renewable Energy Directive (RED) into Act on Air Protection no. 201/2012 and to Government Directive no. 351/2012. Goals stemming from that legislation are shown in Table 4-8.

Table 4-8 GHG emission reduction targets in the transport sector in Czech Republic

Period	Obligation to reduce GHG emissions by (%)	Minimum GHG emissions savings in biofuels (%)	Share of biofuels and renewable electricity in transportation on total consumption (% energy content)
2014 - 2016	2	35	5,71
2017 - 2019	4	50	8,00
2020	6	60	10,00

5 PRACTICAL ASPECTS OF UER IMPLEMENTATION

The present Section concerns the assessment of UER accounting and implementation in the EU and in Member States, based on the available information to date. The analysis focuses on the issues of verification, additionality, double counting and potential implementation procedures that are expected to be required by the Member States.

5.1 Monitoring, Reporting and Verification

The FQD Implementing Measure requires that the upstream emissions reductions are calculated and verified in accordance with international standards, specifically ISO 14064, ISO 14065 and ISO 14066:

"*UERs shall be estimated and validated in accordance with principles and standards identified in International Standards, and in particular ISO 14064, ISO 14065 and ISO 14066. The UERs and baseline emissions are to be monitored, reported and verified in accordance with ISO 14064 and providing results of equivalent confidence of Commission Regulation (EU) No 600/2012 (1) and Commission Regulation (EU) No 601/2012 (2). The verification of methods for estimating UERs must be done in accordance with ISO 14064-3 and the organisation verifying this must be accredited in accordance with ISO 14065.*"

In the following paragraphs, the relevant ISO standards are being further analysed, in order to provide a better understanding of the implications and issues relevant to the measurement and monitoring of GHG emissions towards UER assessment.

5.1.1 Overview of ISO Standards

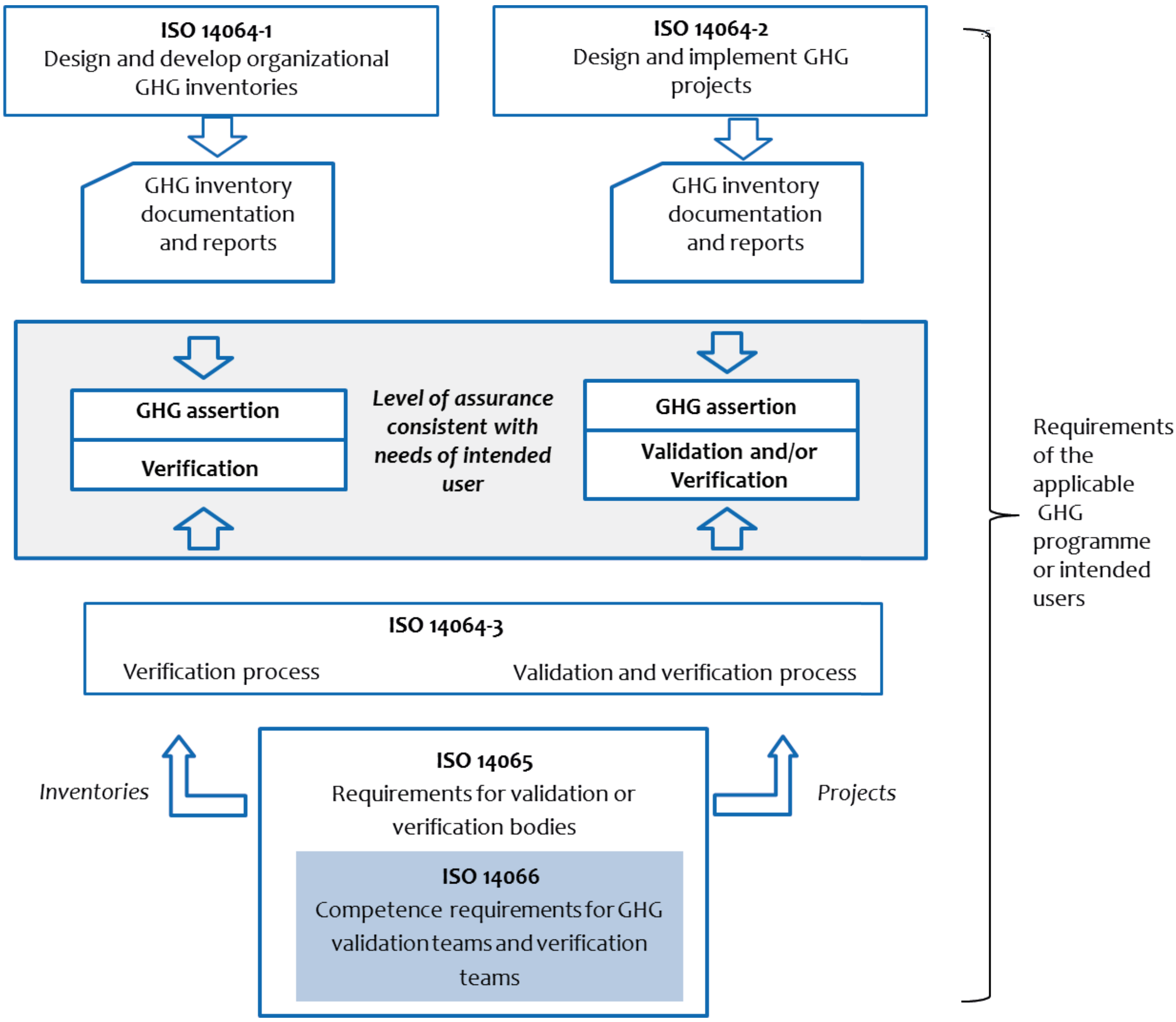
ISO 14064 consists of three parts, each with a different technical focus. Parts 1 and 2 are specifications for the quantification, monitoring and reporting of GHG emissions and emission reductions (as well as removal enhancements), respectively, and Part 3 is a specification for the validation or verification of GHG assertions.

Part 1 of the standard is entitled "*Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals*". This part of the standard addresses the conducting of greenhouse gas emission inventories of organizations using a bottom up approach to data collection, consolidation and emissions quantification, by providing principles and requirements for the development of the organization's GHG inventories.

Part 2 of the standard "*Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements*" addresses quantification and reporting of emission reductions from project activities. Its purpose is to provide principles and specifications for the development of activities specifically designed to reduce GHG emissions or increase GHG removals.

Part 3 of the standard is entitled "*Specification with guidance for the validation and verification of greenhouse gas assertions*". This part of the standard establishes a process for verification of a greenhouse gas statement, including organization of inventories, regardless of whether or not the inventory was developed under Part 1. This verification process is also applicable whether the verification is being conducted by an independent third party verifier or by an organization's internal auditors.

Figure 5-1 Relationship between the ISO 14064, 14065 and 14066 (Source: www.iso.org)



ISO 14065 is entitled "*Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition*". It requires that a validation and verification body establishes and maintains a procedure to manage the competence of its auditing personnel. GHG validation and verification bodies must ensure that auditing teams have the necessary competence to effectively complete the validation or verification process. Supporting these principles are general requirements based on the tasks that the validation or verification teams must be able to perform, and the competence required to do so.

ISO 14066: "*Competence requirements for greenhouse gas validation teams and verification teams*" provides GHG validation teams and verification teams with guidance for evaluation. To achieve consistency in the international marketplace and maintain public confidence in GHG reporting and other communications, there is a need to define competence requirements for GHG auditing teams. ISO 14066 is used in conjunction with ISO 14065.

Figure 5-1 presents the relationship and interaction between ISO 14064 (all three parts), 14065 and 14066.

ISO 14064-2 specifies principles and requirements for determining project baseline scenarios and for monitoring, quantifying and reporting project performance relative to the baseline scenario and provides the basis for GHG projects to be validated and verified. It sets, therefore, a **comprehensive framework in assessing UER projects**, which are in turn validated in accordance with ISO 14064-3 by a team of competent verifiers according to ISO 14066 working for a competent organization following the principles of ISO 14065.

5.1.2 ISO standards for UER implementation

ISO 14064-2 "*includes principles and requirements for determining project baseline scenarios and for monitoring, quantifying and reporting project performance relative to the baseline scenario*". It is, therefore, vital to determine the baseline level of emissions relevant to the concerned project. The definition of baseline scenario, as given in the ISO Standard: "*hypothetical scenarios for GHG emissions and removals that would have occurred in the absence of a proposed project*", indicates that the assessment of baseline GHG emissions must be based on a business as usual scenario, so as to prove that any concerned project is additional to "*common practice*". The notion of additionality and the issues linked to it will be addressed in the next paragraphs.

It must also be noted that ISO 14064 defines a set of requirements concerning the principles of conservativeness, completeness, consistency and accuracy. The term conservativeness means that in emissions estimation one should take reasonable steps to avoid overestimating emission reductions, even where this creates a possibility that reductions will be underestimated. Completeness means that all relevant GHG emissions and sinks should be assessed, and all relevant information should be provided to validators and verifiers. Consistency allows comparisons to be made in GHG related information. Accuracy means that all practical steps should be taken to reduce uncertainty and any systematic biases in emissions reduction calculation. The principle of conservativeness does not conflict with the principle of accuracy; satisfying both requires that once uncertainty has been minimized to a realistic extent, the values chosen should result in a conservative estimate of emission reductions.

Reporting requirements

ISO 14064-2 states that "*The project proponent shall prepare and make available to intended users a GHG report. The GHG report shall identify the intended use and intended user of the GHG report, and shall use a format and include content consistent with the needs of the intended user*". The definition of intended users in the case of UER crediting is vague and most probably will include national administrators within the Member States; however, the intended users may make the report available to the public, although it is not required by the standard itself.

The Implementing Measure sets a list of reporting requirements in order for UER credits to be accounted. These include:

- Starting date of the project (which must be after 1 January 2011);
- Annual emissions reductions (gCO2e);
- Duration for which the claimed reductions occurred;
- Project location closest to the source of the emissions in latitude and longitude coordinates in degrees to the fourth decimal place;
- Baseline annual emissions prior to installation of reduction measures and annual emissions after the reduction measures have been implemented in gCO2eq/MJ of feedstock produced;
- Non-reusable certificate number uniquely identifying the scheme and the claimed greenhouse gas reductions;
- Non-reusable number uniquely identifying the calculation method and the associated scheme;
- Where the project relates to oil extraction, the average annual historical and reporting year gas-to-oil ratio (GOR) in solution, Reduction of upstream greenhouse gas emissions from flaring and venting reservoir pressure, depth and well production rate of the crude oil.

Besides the above listed reporting requirements relevant for GHG emissions reduction projects, ISO requires establishment of monitoring procedures, that must contain the following information:

- purpose of monitoring;
- types of data and information to be reported, including units of measurement;
- origin of the data;
- monitoring methodologies, including estimation, modelling, measurement or calculation approaches;
- monitoring times and periods, considering the needs of intended users;

- monitoring roles and responsibilities;
- GHG information management systems, including the location and retention of stored data.

5.1.3 EU Regulations referenced in the Implementing Measure

In addition to the above mentioned ISO standards, EC Directive 2015/652 states that "*The UERs and baseline emissions are to be monitored, reported and verified in accordance with ISO 14064 and providing results of* ***equivalent confidence of Commission Regulation (EU) No 600/2012 and Commission Regulation (EU) No 601/2012****. The verification of methods for estimating UERs must be done in accordance with ISO 14064-3 and the organisation verifying this must be accredited in accordance with ISO 14065*".

The above mentioned regulations provide a set of principles for reporting, monitoring and verifying GHG emissions for installations reported under the EU ETS, most commonly known as Accreditation and Verification Regulation (AVR). According to the EU Guidance Document on the relation between AVR and ISO 14065, the following main principles have to be adhered to in any GHG verification:

- Decisions are based on objective evidence obtained through the verification process and not influenced by other interests or parties (impartiality);
- Personnel have the necessary skills, experience and capacity to effectively complete the verification (competence);
- The verification opinion statement is based on the evidence collected through an objective verification;
- Timely information about the status of the verification is accessible or disclosed appropriately to the client and other users;
- Confidential information obtained or created during verification activities is safeguarded and not inappropriately disclosed.

In brief, Commission Regulation 600/2012 sets the requirements for verification and the accreditation of verifiers, and Commission Regulation 601/2012 sets the requirements for monitoring and reporting by installation. However, Member States may apply more specific requirements based on their understanding of the ISO standards and the EU Regulations.

The key verification requirements, as reflected in Commission Regulation (EU) No 600/2012 may be summarised as follows:

- The process of verifying emission reports shall be an effective and reliable tool in support of quality assurance and quality control procedures;
- The verifier must carry out verification in the public interest and with an attitude of professional scepticism of the claims being verified;
- The verifier shall conduct substantive testing using analytical procedures, including verifying data and checking the monitoring methodology, and shall conduct site visits;

- All verification reports shall be independently reviewed;
- Verifiers shall be impartial and independent from an operator;
- All verifiers shall be accredited for the scope of activities being verified.

The key reporting and monitoring requirements, as reflected in Commission Regulation (EU) No 601/2012 may be summarised as follows:

- Monitoring and reporting should be complete, consistent, comparable, transparent, and accurate
- Procedures should be maintained for the management and quality control of data resulting from monitoring and reporting activities
- All data should be internally reviewed and validated in addition to the verification process
- Operators should keep records of all relevant data and make appropriate corrections

5.2 Additionality

According to Directive EC/2015/652, "*It is not necessary to prove that UERs would not have taken place without the reporting requirement set out in Article 7a of Directive 98/70/EC*". However, ISO 14064-2 explicitly states that it "*deals with the concept of additionality by requiring that the GHG project has resulted in GHG emission reductions or removal enhancements in addition to what would have happened in the absence of that project*". It does not use the term "additionality", prescribe baseline procedures or specify additionality criteria. This second part of ISO 14064 requires the project proponent to identify and select GHG sources, sinks and reservoirs relevant for the GHG project and for the baseline scenario. In order to be compatible with the broadest range of GHG programmes, it does not use the term "boundaries" to describe which GHG sources, sinks and/or reservoirs are considered for quantification, monitoring and reporting, but instead uses the concept of relevant GHG sources, sinks and/or reservoirs. Thus the project proponent may apply additionality criteria and procedures, or define and use boundaries consistent with relevant legislation, policy, GHG programmes and good practice.

5.2.1 Definition of baseline

Although the FQD does not include a reference on additionality, the above statement makes it clear that in order for emission reduction projects to be quantified towards the acquisition of UER credits, **it is essential to prove that the emissions changes are additional to what would have been expected in a business as usual scenario.** Therefore, even though the project proponent must prove that the project would not have been implemented under business as usual assumptions, it is not necessary to prove that the requirements of the FQD and/or UER crediting were a driver of project development. Besides, according to Article 5.4 of ISO 14064-2 "*The project proponent shall select or establish, justify and apply criteria and procedures for demonstrating that the project* *results in GHG emissions reductions or removal enhancements that are additional to what would occur in the baseline scenario*". It is, thus, essential to define what is considered as baseline scenario in each case.

ISO 14064-2 provides a definition of baseline scenario as the "*hypothetical reference case that best represents the conditions most likely to occur in the absence of a proposed greenhouse gas project*" and notes that "*the baseline scenario concurs with the GHG project timeline*". The project proponent needs to consider "*the project description, including identified GHG sources, sinks and reservoirs; existing and alternative project types, activities and technologies providing equivalent type and level of activity of products or services to the project; data availability, reliability and limitations; other relevant information concerning present or future conditions, such as legislative, technical, economic, sociocultural, environmental, geographic, site-specific and temporal assumptions or projections*". The **principle of conservativeness** dictates that "*the predictive quality of quantifying many baseline scenarios, where there is the risk of over-estimating GHG emissions, requires a different approach. Consideration should be given to all feasible baseline scenarios for GHG emissions, and the selected scenario should be plausible over a range of assumptions for the duration of the baseline application. Usually a baseline methodology is used to select the baseline scenario. A conservative scenario is usually adopted among scenarios that are equivalent in terms of completeness, consistency, transparency and relevance*".

In establishing the baseline case it would be expected that a project proponent should demonstrate either that the baseline case would be consistent with local legislation, or that local legislation represents normal business practice. It should also be demonstrated that the baseline case would be considered financially viable – i.e. that financial considerations alone would not have been reasonably expected to cause the project participant to implement the project in question. In brief, a system of additionality requirements based on ISO 14064 would determine additionality at the discretion of the qualified validator appointed for the project, and with reference to any guidelines set in place by the body administering the crediting scheme in question, whether a private entity or a national administrator[27]. In order to ensure equal crediting criteria across the EU, it will, therefore, be important for Member States to establish appropriate schemes for measurement and reporting of UERs.

In addition, according to ISO 14064-2, "*the criteria may consider a balance between practicality and cost-effectiveness with the GHG project principles*". A verification scheme may therefore legitimately allow an alternative definition of baseline dictating that the cost reduction delivered by the project must be proportionate to any reduction of emissions.

Emission savings must be calculated as the difference between the project and baseline scenarios. **For emissions reductions to be eligible to be claimed as UERs they must be**

[27] "The reduction of upstream greenhouse gas emissions from flaring and venting", ICCT, 2014

additional to any emission changes that would have been expected in the most likely scenario (baseline). Under certain conditions, projects may be considered ineligible unless they are developed with an explicit scope of GHG emissions reduction, including energy efficiency projects.

5.2.2 Project boundaries

For the purpose of the FQD Implementing Measure, "*upstream emissions* means all *greenhouse gas emissions occurring prior to the raw material entering a refinery or a processing plant where the fuel, as referred to in Annex I, was produced*", while in Annex I, it is stated that "*UERs shall only be applied to the upstream emission's part of the average default values for petrol, diesel, CNG or LPG*". Therefore, any facility or process included in the fossil fuel supply chain prior to entering the refinery, for the case of oil products, or the processing facility, in the case of natural gas, is eligible to report emission reductions.

According to ISO 14064-2, the reported emissions must cover all sources, sinks and reservoirs controlled, related to, or affected by the project in question. As mentioned previously, this part of ISO 14064 does not contain any definition about project boundaries. ISO 14064-1, on the other hand, sets the principles for GHG inventory design and development, in terms of organisational and operational boundaries, although it does not explicitly define the system boundaries in which the concerned emission reductions are set.

In terms of geographical location, the project boundary will typically include the fossil fuel extraction site, collection, transport, and processing infrastructure up to the point at which any processed material leaves the site, and all new infrastructure developed as part of the project aiming at reduction of GHG emissions. It could also include new or existing offsite infrastructure if these are determined to be relevant to the emissions performance of a project, such as a gas gathering and processing plant for APG utilisation. ICCT gives a detailed analysis of potential emission sources that may be included within the UER project boundaries. However, **there is still a lot of room for interpretation for system boundaries of projects accounted under UER** crediting mechanisms. Their definition must be based on a common understanding among project proponents in order to avoid uncertainty in proving the additionality of proposed projects.

5.2.3 Definition of additionality by Member States

The interpretation of the principle of additionality by Member States authorities must take into account all legal, economic and technical requirements regarding the definition of baseline relevant to a UER project. Member States must have a **common understanding and set criteria** in order to verify eligible projects. The baseline should reflect a business as usual case that may change over time, and thus cannot be fixed based on emissions rates at a given moment. Assessment of sources and sinks controlled by the project proponent or affected by the project, particularly in projects located in countries outside the EU (which will most probably be the most common case), could prove to be considerably difficult.

5.3 Double Counting

Double counting occurs when a single GHG emission reduction or removal, achieved through a mechanism issuing units, is counted more than once towards attaining mitigation pledges or financial pledges for the purpose of mitigating climate change[28]. Project proponents with whom fuel suppliers enter into commercial arrangements must not make the same UERs available to other fuel suppliers or redeem them for compliance with other regulations.

The FQD Implementing Measure does not explicitly specify any steps that must be taken to prevent double counting. Depending on whether Member States feel that it is necessary to implement measures to prevent double counting, there may be a high risk of it happening. It is expected that each Member State will appoint a national administrator responsible for receiving and confirming reports of emissions reductions. Such an administrator would be expected to verify that UER projects are not double counted within a Member State.

Double counting may occur, in the case of UERs, in two different ways:

1. by claiming the same UERs in more than one Member State;
2. by issuing UER credits for projects that have also been registered for crediting within other mechanisms, such as the CDM or JI.

Assessing and addressing double claiming is more difficult in the second case, where two separate mechanisms are involved. In a fragmented carbon market, with multiple mechanisms under international, bilateral, national or non-governmental governance, there is a risk that two mechanisms issue units for the same emissions or emission reductions. Overlap could also occur between cap-and-trade mechanisms and crediting mechanisms, such the CDM and the EU ETS.

In order to avoid double claiming between Member States, ideally, registration systems should be in place to ensure that any credits can only be redeemed in one Member State only. This could be enabled by the establishment of a central European database, or by other information sharing measures between national administrators. For the purpose of identifying any attempted multiple claiming, national administrators will need to access information on UERs claimed for compliance in all other Member States. This can be solved by **establishing a system of unique identification of UERs** generated by the same project within the same year. It is important that all Member States share a common

[28] Addressing the risk of double counting emission reductions under the UNFCCC, Stockholm Environment Institute, 2014

reporting format for UER certificates, so as to avoid confusion in the identification of batches of credits.

Proper verification mechanisms, such as the processes described in the referenced ISO Standards will allow minimising the risk of multiple claiming of the same batch of UER credits. **The whole process of unique identification can be overseen by a central European authority, which will coordinate the correspondence between Member States and will be responsible for the set-up and functioning of a central UER database**.

5.4 Potential implementation by Member States

In order to have a legal effect in the Member States, the Fuel Quality Directive must be transposed into national law and implemented. Typically, Directives leave considerable discretion on Member States with respect to the implementation of specific elements. This flexibility could lead to enhanced verification and monitoring requirements (imposing additional requirements not intended by the European Commission). In other countries, it could lead to a weakening of verification, monitoring or double counting prevention systems. In any case it is up to Member States to develop relevant legislation that will describe the specific implementation details.

The experience from the EU ETS and the recent transition from a distributed crediting system to a centralized approach with a single EU registry, with standardized monitoring, reporting and verification procedures among Member States shows that under such a system, credit trading is easier, less administration and transaction costs are required and the potential of fraud/double counting is reduced. It is therefore assumed that this is the most plausible approach to be implemented also for the UER registry. The actions to be taken by MS and are described below are based on this assumption.

Apart from the transposition of Directive EC/2015/652 into national legislation, the implementation of a series of actions is required including the establishment of competent bodies and monitoring mechanisms. Some basic steps that will have to be followed by MS are described below:

A. Transpose and implement the Implementing Measure

Each Member State will have to transpose the Directive EC/2015/652 into national legislation so as to allow UERs to be accounted towards compliance under the FQD. The way that Member States implement the FQD could vary broadly with respect to various issues, with the most prominent being:

- **Eligibility.** National legislators have a large degree of flexibility in defining eligibility. As discussed, the FQD describes in rough lines eligible projects, which are not limited to those reducing venting and flaring emissions. Furthermore, ISO 14064-2 limits the scope of eligible projects to those that are additional to the appropriately defined baseline scenario. In this framework, Member States will have to define with precision and clarity which projects are considered as eligible.

- **Verification.** To be eligible under the FQD, the monitoring and verification process must follow the requirements for auditors and verification practices described in ISO 14065 and ISO 14066. National legislation should make reference and describe these requirements as well as any additional that might be required.
- **Compatibility/alignment of UERs with other compliance options.** The Implementing Measure is not absolutely clear on how UERs could be used for the national implementation of the FQD. The only pertinent requirement is that the national implementation should allow regulated parties to include reported UERs in the calculation of the specific GHG intensity of the fuel they supply. National legislation should include all relative provisions on the cooperation/alignment between market schemes, UER schemes, biofuels and all applicable measures and policies that can be used to exhibit compliance with the FQD.

B. Appointment of national administrator

Each Member State will have to appoint an administrator (agency /body /institution /entity /ministry) responsible for monitoring and receiving emission reductions from regulated parties, and for confirming that reported emissions reductions comply with the requirements of the FQD. National legislation should pay attention to providing all necessary access information on UERs claimed for compliance in all other Member States to avoid double counting of UERs. All regulated parties will have to submit at the end of the year regular reports to their national administrators describing how they have complied with their carbon intensity reduction targets, according to the national targets set – if applicable. This system should work in parallel and in cooperation with the schemes envisaging emission reductions through alternative fuels.

C. Identification of eligible emission reduction schemes

As discussed earlier, various upstream emission reduction schemes can be used to achieve compliance with the FQD. These schemes could include already functioning mechanisms or others that will be introduced for the purpose of compliance with the FQD. Particular attention should be paid to schemes that are not fully compatible with the requirements outlined in the FQD Implementing Measure and might have additional reporting requirements. National administrators should assess the emission reduction schemes under which economic operators would like to report UERs and check whether these are compliant with the FQD requirements. Potentially national legislation could include provisions identifying in advance eligible schemes, without additional requirements. Furthermore, primary or secondary legislation could prescribe the development of methodologies and protocols for facilitating and systematizing the process of monitoring and verification.

D. Assessment and validation of reported data

Following the submission of emission reduction reports by regulated parties the national administrator should assess whether all required data have been reported appropriately and whether all reporting requirements are compliant with the FQD and its Implementing Measure. National legislation should clearly prescribe the duties and responsibilities of the national administrator with respect to verification of UERs that have been awarded. Any credits awarded shall be subject to monitoring and verification consistent with the requirements of ISO 16064-3 as applied to the reporting requirements outlined in ISO 14064-2, and the verifiers should have been competent under ISO 14065 and 14066. There is the possibility that some schemes could have sufficient internal consistency checks and require no additional checks. Additional verification actions could include:

- Requiring additional documentation of the competence of project verifiers or validators;
- Requiring additional evidence of data monitoring processes;
- Verifying the veracity of reported credit serial numbers;
- Undertaking independent validation of project baseline assumptions.

E. Report data to a central data repository

As discussed, the most likely case is that the European Commission will appoint a central data holder for collecting information on upstream emissions reductions claimed under the FQD. In this case when the national administrator accepts emission reduction claims, data on these claims should be reported to the central data holder for the European Union.

F. Prevention of double counting

Assuming the appointment of a centralized UER repository in the case of detection of double counting (such as double serial numbers) the European data holder should inform national authorities. The national administrator should then undertake an investigation to detect whether the regulated party fulfils its target under the FQD and identify the possibility of a fraud.

5.5 Methodological issues

There are a few matters related to monitoring and reporting procedures of UERs that require further guidance and clarification.

Timeline for crediting UERs

The Implementing Measure is not clear on whether the upstream emission reduction credits can only be claimed in the year of occurrence, or if the emission reduction credits related to a certain eligible project may be cumulated in the 2011-2020 period towards the fulfilment of the 2020 target (6% GHG emissions reduction in the transport sector). In addition, the FQD leaves room for interpretation: "*This reduction should amount to at least 6 % by 31 December 2020, compared to the EU-average level of life cycle greenhouse gas emissions per unit of energy from fossil fuels in 2010, obtained through the use of biofuels, alternative fuels and reductions in flaring and venting at production sites*". However, it would only be reasonable to account UER credits from eligible projects, **only if they are generated during the year of compliance against the FQD target, i.e. 2020**.

Moreover, it should be required to be able to prove that the requirement of additionality is being respected in any case, thus projects that are currently in the pipeline through new regulations or other certification systems (new EPA rules, Alberta Offset Scheme, CDM etc.) are not accounted towards the FQD target, even if they are completed within the period 2011-2020.

Interpretation by Member States

Member States may impose their own interpretation to the referenced ISO standards. In order to comply with the GHG reporting requirements explained in the previous Sections. Member States representatives may impose additional verification and monitoring criteria, in line with the principles set by the ISO standards.

ISO 14064 is generally compliant with most GHG emissions reductions programmes, either voluntary or not. In case Member States allow crediting of UERs issued by the means of other GHG programmes or schemes, ISO provisions should be applied to all candidate projects, in order to ensure compliance with the requirements of the FQD and its Implementing Measure.

In order to ensure that the appropriate quality is delivered by all of FQD-eligible UERs across the EU, it is therefore necessary for **Member States to establish appropriate common criteria** for measurement and reporting under UER schemes.

Compliance against the FQD baseline year

A methodological issue related to the achievement of the FQD targets in 2020 is the fact that emission reductions (when compared to the baseline of 2010) could be achieved only phenomenally and specifically for the purpose of the FQD compliance. This is due to the fact that actual emissions might increase or decrease between the baseline of 2010 and the target year 2020 and could, thus, lie higher or lower than the baseline emissions of 2010 minus the emission reductions prescribed under the FQD. This means that in 2020 rough savings (brutto) could allegedly appear as significant but net actual (netto) emissions could be lower or even increase.

Another significant issue is that of the **equal treatment among different emission reduction options,** which count against the FQD target. For instance, there is a requirement of full LCA for biofuels; while only a relatively simple CO2 saving calculation is prescribed for UER. Furthermore, in the case of biofuels there is actual deployment while in the case of UER savings these appear to have an accounting character. Thus, despite the fact that the accounting of net emission savings is the correct methodology it should apply to all emission reduction options equally.

Crediting of methane emissions

Under CDM and JI, venting reduction projects do not receive additional credits related to the higher global warming potential of methane. In contrast, the **Directive 2015/652 allows the crediting of methane reduction**, by using the appropriate GWP to transform tonnes of emitted methane into tonnes of CO2 equivalent. However, the principle of conservativeness, as dictated by ISO 14064, requires that reduction of methane sources should be credited only for the GHG benefit of reducing the equivalent emissions of carbon dioxide.

In fact, CDM makes the assumption that all associated gas related to a certain oil field will be burned either way, whether by flaring for no practical purpose, or at a power generation facility. If CDM and JI methodologies are taken as reference for an UER accounting methodology and taking into account the principle of conservativeness, methane emissions will most probably be accounted on the “safe side”, i.e. by considering that all APG production would be flared in a business as usual scenario. There is therefore an uncertainty on the way to treat the credits reduction of actual methane emissions in the upstream sector, which needs to be clarified.

6 KEY FINDINGS

6.1 Overview of Tasks

The 1st Task of the Study (Chapter 2) provides an overview of upstream emission reduction measures, covering mainly technological solutions and includes three parts:

1. *Overview of upstream emitting activities*: The main sources of upstream emissions are assessed, particularly in the oil sector. **Flaring, venting and fugitive emissions represent the most important source of upstream GHG emissions** from oil production operations. Combustion of Associated Petroleum natural Gas (APG) is called flaring, while releasing it to the atmosphere is known as venting. Fugitive emissions refer to unintentional methane leakages from oil and gas operations, whereas venting emissions are related to the intentional release of methane to the environment for maintenance or other reasons. Methane emissions predominantly occur during natural gas production and transportation, whereas oil upstream activities mainly emit CO_2 which comes from combustion. Since natural gas is not widely used in the EU transport sector, methane is not considered as a significant contributor to the total GHG emissions of the EU transport sector.
2. *Upstream emission reduction technologies*: Major technologies aimed mainly at venting and flaring reduction and APG utilisation are presented and qualitatively assessed against a list of criteria/drivers. For each site where APG is flared, a number of alternative solutions exist, which aim at recovering and utilizing part of the gas. The economic viability of each of these APG utilisation options is affected by a large number of factors, e.g. gas characteristics, location and presence of existing infrastructure, market conditions, etc. **The optimal solution for a particular site is thus highly case specific.** Regarding methane emissions, while there is high potential for abatement of methane emissions mainly in the natural gas sector, they are not currently widely applied for technical and economic reasons.
3. *Upstream emission reduction incentives*: Specific oil producing countries are analysed with respect to regulations they have adopted to reduce flaring as well as major flaring reduction projects that have been constructed or are currently under development. The countries, which have been assessed, are those being among the highest upstream GHG emitters and in parallel significant suppliers of the EU, namely Russia, Nigeria, Iraq and Iran. To these countries, the Consultant has added Norway, due to the technological and regulatory best practices it implements, along with Canada, as it is a major producer of unconventional fuels.

Unconventional oil and gas are expected to play an increasing role in the EU market in the near future.

Flaring emissions from Russian oil fields are extremely high - the largest among all oil producing countries. According to the World Bank's GGFR satellite studies (2011), Russia was in 2010 by far the country in the world flaring the biggest amount of associated gas (34.2 bcm), followed by Nigeria (15.2 bcm), Iran (11.3 bcm) and Iraq (9.1 bcm). All these countries are major fossil fuel suppliers of the EU and they relate to important upstream emission reduction potential. Russian companies have been making efforts to develop APG utilisation facilities in the last few years, some of which may be used for UER crediting. Other major APG utilisation projects are operating or are under development in Nigeria and in Iran that could potentially be accounted towards the FQD targets.

The 2nd Task (Chapters 3 and 4) deals with the potential of upstream emission reduction, while analysing policies and incentives undertaken worldwide for this purpose. In this context the following issues are being analysed:

1. *Incentives and policies aimed at upstream emissions reduction*: Relevant policy options are presented, with a specific focus on market mechanisms based on emission intensity standards, which will presumably form the basis for the creation of an UER crediting scheme. **Cap-and-trade systems** are particularly presented, as they have emerged as the internationally preferred market mechanism for mitigating GHG emissions. Special reference is made to the cases of California Low Carbon Fuel Standard and the British Columbia Renewable and Low Carbon Fuel Requirements Regulation, as well as **emission offset mechanisms** such as CDM and JI, since projects registered under these mechanisms are candidate to be eligible for UER crediting.
2. *Assessment of UERs subject to be accounted for under the FQD requirements*: Eligibility of potential projects in an UER scheme is assessed, followed by a brief estimation of technical and economic potential of UER. According to pertinent literature, total carbon mitigation potential from economically profitable flaring and venting reduction projects in the oil sector in the EU, Canada, Nigeria, Russia and the US combined **can be in the range of 127-143 MtCO2e per year, at negative abatement costs (i.e. profits)**, with Russia being able to deliver approximately half of that potential.

   With respect to FQD compliance, at a CO2 credit value of carbon price of \$20/tCO2e, approximately **24 MtCO2e of annual UER** could be delivered for a cumulative crediting period of 15-20 years. This would amount to slightly less than half of the FQD target of a 6% reduction in the carbon intensity of European transport fuels. In the case that only 1 year crediting period (2020) is eventually applicable (according to the Implementing Measure requirement) the potential is significantly lower ranging from 2.3 million tonnes CO2eq (for \$20/tCO2e carbon price) to 15.5 million tonnes CO2eq for (for \$200/tCO2eq carbon price). **This estimation corresponds to a percentage being approximately between 5% and 30% of the 6% FQD target.**

The 3rd Task (Chapter 5) deals explicitly with the practical aspects of the potential implementation of Article 7a of the FQD and the UER crediting scheme. The European Commission recently adopted the Directive 2015/652/EC, laying down calculation methods and reporting requirements for the implementation of the Article 7a of the Fuel Quality Directive, which allows for the opportunity to use 'Upstream Emissions Reductions' (UERs) to comply with the target of 6% reduction of GHG emissions in the European Union's transport fuel supply. The eligibility of projects, which are subject to be accounted for UER credits, remains unclear, as the FQD Implementing Measure leaves a lot of room for interpretation. The main projects, which will most likely be included in the UER scheme, are in the area of venting and flaring reduction from the oil and gas i. e. upstream activities, in all geographic regions. Carbon Capture and Storage projects are also possible to be accounted for, however there are very few projects under consideration. According to the Directive 2015/652/EC fossil fuels companies are obliged to report **additional information** in order to define the GHG intensity of the different fuel pathways (which, according to the Directive 2015/652/EC, are from now on called Feedstock Trade Names – FTN). The new requirements allow for more equal treatment with biofuels GHG reporting and include, among others:

- Place of origin of fossil fuel (country and processing facility)
- GHG average default value per fuel type

The practical aspects reviewed include:

1. *Monitoring and Verification*: The FQD Implementing Measure requires that the upstream emissions reductions are calculated and verified in accordance with international standards, specifically ISO 14064, ISO 14065 and ISO 14066. In brief, ISO 14064-2 specifies principles and requirements for determining project baseline scenarios and for monitoring, quantifying and reporting project performance relative to the baseline scenario and provides the basis for GHG projects to be validated and verified. It sets, therefore, a **comprehensive framework of assessing UER projects**, which are in turn, validated in accordance with ISO 14064-3 by a team of competent verifiers according to ISO 14066 working for a competent organization following the principles of ISO 14065. Finally, an analysis of verification, reporting and monitoring requirements according to Directives 600/2012 and 601/2012 is provided.
2. *Additionality*: Although the FQD does not include a reference on additionality, ISO 14064-2 clarifies that in order for emission reduction projects to be validated, it is essential to **prove that the emissions changes are additional to what would have been expected in a business as usual scenario**. In order to provide proof of additionality, it is necessary to set a baseline scenario, above which emission reduction credits can be claimed for compliance. The definition of baseline is among the most important issues to be further clarified in the process of setting up an UER mechanism in Member States.
3. *Double counting*: The FQD Implementing Measure does not explicitly specify any steps that must be taken to prevent double counting. However, in order to avoid

multiple claiming of the same credits, it is important to set up a scheme that allows **uniquely identifying each batch of UER credits** by using proper verification procedures. The national administrators may then refer to a centralised database, operated by the EC, in order to verify that claimed UERs are not already redeemed by another entity.

4. *Potential implementation by Member States*: Practical transposition matters are being discussed. **In each Member State a national administrating body must be appointed**, which will be responsible for monitoring and receiving emission reductions from regulated parties and for confirming that reported emissions reductions comply with the requirements of the FQD.

6.2 Concluding remarks

The European Commission has prescribed the development of a mechanism for counting of UER savings **exclusively towards the compliance under the FQD target**. UERs cannot be counted towards the achievement of the targets of UNFCCC or the Kyoto-Protocol for a specific Member State. According to the GHG inventory methodologies, projects leading to upstream GHG emission reductions have to be accounted a) in the countries where these are implemented, or b) in the industry sector of the respective countries.

The UER scheme **cannot be considered as an explicit climate change policy tool** in the context of a wider framework (such as the EU ETS for the implementation of the Kyoto Protocol) but as an accounting mechanism towards the FQD compliance specifically addressed to the EU transport sector. Nonetheless, in the Consultant's view, UERs have to be seen from a broader point of view with respect to the climate protection commitment of the EU (20% decrease of GHG emissions by 2020) and further measurements to reach the 1,5° C goal of COP21 in Paris. Therefore, even though UERs could in principle form an instrument for climate change policy, the current single year target of 2020 and the fragmented design of the mechanism so far do not guarantee the effectiveness of the UER mechanism in the longer run. However, it should be noted that the revision of the FQD which is expected by the EC within 2016 could set new targets and create new obligations in the fossil fuel sector.

Much discussion and interpretation is currently in place on whether credits should be awarded in one year (2020) only, or whether emission reductions taking place over the 2011-2020 period could be aggregated for reaching the target in the compliance year. In the Consultant's perspective, emission reduction credits are not expected to be checked for compliance in a cumulative manner, thus only UERs generated in the corresponding calendar year should be considered eligible.

The actual implementation of the UER mechanism as a means for the achievement of the FQD target could face several challenges. The way the Implementing Measure attempts to settle various practical and methodological issues with respect to UER implementation **leaves several vague and unclear points that could hamper its effectiveness**. These points are determined by the issues of 1) **project eligibility** and the corresponding notion of 2) **additionality**, 3) **double counting** and 4) the **development of common rules between MS**, as well as of a **centralized EU registry** for UERs. Furthermore, the ongoing discussion and consultation for the practical implementation of UER can be characterized by large delays and ambiguities which could severely affect the smooth implementation of the UER mechanism. In the Consultant's opinion, the complete establishment of the UER mechanism could take up to 3 years (i.e. end of 2018) which would entail a large administrative burden and cost, potentially disproportionate to its envisaged effectiveness. The issues that need clarification, related to the implementation of a UER scheme are summarized in the following:

1. **Project eligibility**: A major issue with respect to UER implementation is the eligibility of projects against FQD compliance as this **will determine the level of difficulty in the achievement of targets and eventually the financial cost of compliance for obliged stakeholders (suppliers)**. The FQD describes in rough lines eligible projects, which are not limited to those reducing venting and flaring emissions. Project eligibility is left to a large extent to the hands of national legislators who have a large degree of flexibility. Furthermore, ISO 14064-2 limits the scope of eligible projects to those that are additional to the appropriately defined baseline scenario. In any case the Implementing Measure and the expected non-legislative guidance that will follow should provide clear directions on which projects could be considered as eligible.
2. **Additionality**: Project eligibility is inextricably related with the issue of **additionality**. Although the FQD does not include a reference on additionality, in order for emission reduction projects to be quantified towards the acquisition of UER credits, **it is essential to prove - as derived from ISO 14064 - that the emission changes are additional** to what would have been expected in a business as usual scenario. Therefore, even though project proponents must prove that the project would not have been implemented under business as usual assumptions, it is not necessary to prove that the requirements of the FQD and/or UER crediting were a driver of project development.
   The effects from removing or loosening additionality requirements would allow for many more UER projects to be eligible and remove significant part of administrative burden. Nonetheless, poor additionality criteria would significantly undermine its purpose. In this case, the project baseline, as well as the project boundaries must be clearly defined. It is therefore **essential to develop common rules** between project proponents and national administrators from Member States on the establishment of these two parameters.
3. **Double counting**: The FQD Implementing Measure **does not explicitly specify any steps that must be taken to prevent double counting**. Depending on whether MS consider that it is necessary to implement measures to prevent double counting, there may be a high risk of occurrence. It is expected that each MS will appoint a national administrator responsible for receiving and confirming reports on emission reductions. Such an administrator would be expected to verify that UER projects are not double counted within a Member State.

4. **Establishment of common rules and criteria among MS**: In general, **monitoring and verification will be implemented according to the referenced ISO standards**. Nonetheless, in order to comply with the GHG reporting requirements, Member States representatives may impose additional verification and monitoring criteria, in line with the principles set by the ISO standards. In order to ensure that the appropriate quality is delivered by all FQD-eligible UER projects across the EU, it is therefore necessary for **Member States to establish appropriate common criteria** for measurement and reporting under UER schemes.
5. **Centralised UER registry**: The experience from the EU ETS and the recent transition from a distributed crediting system to a **centralized approach with a single EU registry**, with standardized monitoring, reporting and verification procedures among Member States shows that under such a system, credit trading is easier, less administration and transaction costs are required and the potential of fraud/double counting is reduced. It is therefore assumed that this is the most plausible approach to be implemented also for the UER registry.

Furthermore, it must be highlighted that actual emissions might increase or decrease between the baseline of 2010 and the target year 2020 and could, thus, lie higher or lower than the baseline emissions calculated for 2010 minus the emission reductions prescribed under the FQD. This means that in 2020 rough savings (gross) could allegedly appear as significant but **net actual emissions could be lower or even increase**.

Last but not least, a significant issue is that of the **equal treatment among different emission reduction options** which count against the FQD target. For instance, there is a requirement of full LCA for biofuels; while only a relatively simple CO_2 saving calculation is prescribed for emissions reduction in the fossil fuel sector. Furthermore, in the case of biofuels there is actual deployment, while in the case of fossil fuels emissions savings, these appear to have an accounting character. Thus, despite the fact that the accounting of net emission savings is the correct methodology in the context of climate change policy in the transport sector, it should apply to all emission reduction options equally.

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