Kenya Air Quality Management Guidelines

(developed for petroleum sector)

FINAL DRAFT

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Contents:

Acronyms

AAS - Atomic absorption spectrometry

AER – Alberta Energy Regulator

AFS - Atomic fluorescence spectrometry

AM – alternative method

AMS – Automatic Monitoring System

ANSI – American National Standards Institute

API – American Petroleum Institute

AQR - Environmental Management and Coordination (Air Quality) Regulations 2014

BAT – Best Available Techniques

BBU - Bitumen Blowing Unit

BTEX - Benzene, ethyl benzene, toluene, and xylenes

C2H6 - Ethane

CASA - Clean Air Strategic Alliance

CCR - continuous catalyst regeneration

CEN - European Committee for Standardization

CFC - Chlorofluorocarbon

CH4 - Methane

CO - Carbon monoxide,

CO2 - Carbon dioxide

COPD - Chronic obstructive pulmonary disease

DI&M – Directed Inspection & Maintenance

DOAS - Differential Optical Absorption Spectroscopy

EIA – Environmental Impact Assessment

EHS – Environmental, Health and Safety

EN – European Norms

ELV - Emission Limit Values

EMCA - Environmental Management and Co-ordination Act

EPA - United States Environmental Protection Agency

FCCU - Fluid Catalytic Cracking Unit

FID - Flame ionisation detection

FPSO – floating production storage and offloading

FTIR - Fourier transform infrared spectrometry;

GFC - Gas filter correlation;

GHG - Green house gases

GWP - Global warming potential (gases)

H2S - Hydrogen sulfide

HAZID - hazard identification study

HAZOP - hazard and operability study

HCl- Hydrogen chloride

HF - Hydrogen fluoride

HFCs – Hydrofluorocarbons

Hg_2Cl_2/$HgCl_2$ - mercury chlorides

IBP – International Best Practice

IED – Industrial Emissions Directive

ISO- International Standard Organization

IEC – International Electrotechnical Commission

IFC – International Financial Corporation

JRC – Join Research Centre

LDRA - leak detection and repair

MoPM – Ministry of Petroleum and Mining

N_2O - Nitrous oxide

NADF - Non-Aqueous Drilling Fluids

NDIR - Non-dispersive infrared spectrometry;

NDUV - Non-dispersive UV spectrometry;

NEMA – National Environment Management Authority (of Kenya)

NF_3 - Nitrogen trifluoride

NH_3 - Ammonia (NH_3) AAS = atomic absorption spectrometry;

NO - Nitric oxide

NO_2 - Nitrogen dioxide

NOC - normal operating conditions

NO_x - Nitrogen oxides

OGI - Optical gas imaging

OTNOC - other than normal operating conditions

PAHs - Polycyclic aromatic hydrocarbons

P-AMS - portable automated measuring systems

PEMS - Predictive Emission Monitoring Systems

PFCs – Perfluorocarbons

PID - Photo ionisation detector;

PM - Particulate Matter

QA/QC - Quality Assurance / Quality Control

RCCU - Residue Catalytic Cracking Unit

SF_6 - Sulfur hexafluoride

SNCR - Selective non-catalytic reduction

SO_x - Sulphur oxides

SO_2 – Sulphur dioxides

SRM – Standard reference method

SRU - Sulfur recovery unit

TDL - Tunable diode laser absorption spectrometry.

TVOC - total volatile organic carbon

VOC - Volatile organic compounds

UK – United Kingdom

UNEP – United Nations Environmental Programme

U EPRA – Upstream Energy Petroleum Regulatory Authority

WHO – World Health Organisation

1. Introduction

1.1 Objectives

This guideline is designed to provide petroleum companies, i.e., those companies conducting operations in the up-, mid- and downstream sectors, with a guidance on how to manage specific matters related to air quality management, and to adopt best international practices in line with Kenya environmental legislation. The guideline addresses specifically the following key matters:

- Best technologies and techniques used in petroleum sector for emission reduction and control;
- Procedure for measurement of air emission in the petroleum sector;
- Standard operating procedures for gas flaring and venting in line with international best practices.

Although this guideline applies to the petroleum sector as a whole, emission regulations from downstream operations to a greater extent already covered by existing regulations. Therefore, the focus of this guideline is primarily on the up and mid-stream sectors of petroleum sector.

Petroleum companies shall observe requirements of this guideline in handling atmospheric emissions from petroleum operations and in the management of air quality in the vicinity of their operations. Requirements imposed by enacted Kenyan law are mandatory for the responsible duty holder, as specified in legislation. Where applicable, the term “must” and “shall” indicates a requirement, while terms such as “recommends”, “expects”, and “should” indicate recommendations based on international best practice, rather than on Kenyan law.

Some recommended practices that are based on international best practice might be in contradiction with current requirements imposed by Kenyan regulations. Such recommendations are referred to in this guideline solely for the purpose of providing general guidance on widely accepted, industry practice. They are not intended to encourage petroleum companies to breach national legislation in any form or fashion.

NEMA along with other competent bodies of Kenya works on alignment of current Kenyan regulations with international best practice as it applies to petroleum sector and introduction of official amendments into corresponding regulations. ***However, at present where Kenyan law and international best practice are not compatible, the former takes precedence over the latter as a default option. Therefore, petroleum companies should not follow international best practice unless official waiver is granted by appropriate state body (-ies) to assure continuation of rights granted under the terms of petroleum contracts.***

The National Environment Management Authority (NEMA) will initiate formal review of these guidelines five years following their publication, to ensure that they continue to reflect up-to-date scientific and technical knowledge. An earlier review may be initiated at NEMA’s discretion, or if petitioned by government, industry or the public, for example, where there is a need to amend Annexes of this guideline earlier.

Petroleum companies shall observe requirements and techniques provided in this guideline in handling air emissions from petroleum operations.

1.2 Scope: Up-, mid-, and downstream operations

This guideline, where practical identifies the requirements of Kenyan environmental legislation on air quality management with a focus on pollutants typically emitted by the petroleum sector. On one hand, it aims at providing petroleum operators with an overview of Kenya’s statute, regulation, policy, or guideline as well as draft legislation containing requirements on the air quality management. On the other hand, it addresses regulatory gaps found in Kenyan legislation. This guideline focuses on obligations imposed on petroleum companies, and includes requirements specifically applicable to other stakeholders involved in the petroleum sector, such as service companies, etc.

This guideline is divided into sections as provided below:

Section 2 aims at describing different source of air emissions and pollutants produced by petroleum sector. The list includes the type of emissions exclusively generated by petroleum sector and does not include any other sources and pollutants that are not specific to this industry.

Section 3 provides for a current status of air quality management processes in Kenya and air quality issues faced by the country.

Section 4 provides for a list of Kenya's laws and regulations that directly or indirectly make provisions related to air quality management. As Kenya air quality regulations are not specific to petroleum sector, this guideline may contravene the requirements of such regulations. NEMA is responsible for updating the regulations or the guideline to align the requirements.

Section 5 of the guideline identifies gaps or matters that are not regulated by Kenyan law as it relates to air quality management. The section identifies two main categories of gaps:

- Gaps arising from vagueness or incompleteness of existing laws and regulation. This category includes instances where regulations fail to provide details on how to comply with an existing requirement, as well as gaps due to failure of local agencies to complement regulations in place.
- Gaps arising from legislation's failure to regulate a specific issue altogether. These types of gaps are caused by the fact that Kenya's environmental law is not tailored to regulate petroleum activities, hence it fails to capture issues specific to the industry.

Section 6 makes for a list of recommended practices related to air quality management and more specifically identifies best technologies and techniques for emission control and reduction, procedures for emission measurements and operating procedures for gas flaring and venting.

Section 7 provides a list of reference documents, such as applicable Kenyan laws and regulations, external international and de-facto international standards and referenced documents used to produce this guideline that provide for amalgamation of best practices for air quality management recommended for application in Kenya by petroleum operators.

Section 8 of the guideline lists acronyms used in the document.

2 Types of air pollutants and emission sources of petroleum sector

Air emissions from the petroleum sector mostly come from the upstream operations (exploration, drilling, production and field processing). Midstream (pipelines and compressors) and downstream operations (refining, storage and distribution) typically contribute a relatively lower level of air emissions.

The main **air emissions** (continuous or intermittent) from upstream onshore, offshore and refining petroleum activities include[1]:

- **combustion emissions** (stationary and mobile, including flaring and venting, continuous and intermittent emissions (e.g., well-testing emissions, safety flaring, engine exhaust, etc.);
- **fugitive emissions** (from pipes, valves, seals, tanks, and other infrastructure components, evaporation ponds and pits, windblown dust (from truck and construction activity))
- **process emissions**

[1] IFC environmental, health, and safety guidelines for petroleum refining, IFC environmental, health, and safety guidelines for petroleum refining, IFC environmental, health, and safety guidelines for offshore oil and gas development, IFC environmental, health, and safety guidelines for onshore oil and gas development

- **auxiliary emissions**, including for example refining flue gas.

Stationary combustion sources include boilers, turbines, steamers, flares, thermal oxidizers, dryers, and any other equipment or machinery that combusts carbon bearing fuels or waste stream materials[2] (like the use of compressors, pumps, and reciprocating and other engines on offshore and onshore facilities[3]).

Mobile combustion sources include support and supply vessels and helicopters[4], highway vehicles, construction equipment, freight trains, upstream/downstream third-party transportation emissions, such as those associated with transporting material inputs or product distribution, are considered Optional Indirect emissions[5].

Fugitive emissions include sudden leaks of vapors from equipment or pipelines, as well as continuous small leaks from seals on equipment. These emissions are not released from vents and flares, but may occur at any location within a facility. At the upstream petroleum facilities fugitive emissions may be associated with cold vents (collected gaseous stream that is directly released to the atmosphere without burning in flare), leaking tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, open tanks for Non-Aqueous Drilling Fluids (NADF) (generating diffuse emissions), and hydrocarbon loading and unloading operations[6]. In petroleum-refining facilities fugitive emissions may occur from leaking tubing, valves, connections, flanges, gaskets, steam traps, packing, open-ended lines, floating roof storage tanks and pump seals, gas conveyance systems, compressor seals, pressure relief valves, breathing valves, tanks or open pits/containments, oil-water separators, and in the storage, loading, and unloading operations of hydrocarbons.

Process Emissions. In petroleum refining and petrochemical industries, the typical processes that take place include separations, conversions, and treating processes like cracking, reforming, isomerization, to name a few. The emissions arising from these processes are termed as process emissions, and are typically released from process vents, sampling points, safety valve releases, and similar items.[7]

Auxiliary emissions originate from units like cooling towers, boilers, sulfur recovery units, and wastewater treatment units. Atmospheric emissions from cooling towers mainly include gases, which are stripped when the water phase encounters air during the cooling process. Refining flue gas from waste heat boilers associated with some process units during continuous catalyst regeneration (CCR) or fluid petroleum coke combustion (flue gas is emitted from the stack to the atmosphere in the Bitumen Blowing Unit (BBU), from the catalyst regenerator in both the Fluid Catalytic Cracking Unit (FCCU) and the Residue Catalytic Cracking Unit (RCCU), and in the sulfur recovery unit (SRU)).

For convenience, pollutants typically emitted by petroleum sector include the following:

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[2] Direct Emissions from Stationary Combustion Sources , https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

[3] IFC environmental, health, and safety guidelines for offshore oil and gas development

[4] IFC environmental, health, and safety guidelines for offshore oil and gas development

[5] Direct Emissions from Mobile Combustion Sources, http://large.stanford.edu/courses/2013/ph240/cabrera2/docs/epa-430-k-08-004.pdf

[6] IFC environmental, health, and safety guidelines for petroleum refining, IFC environmental, health, and safety guidelines for petroleum refining, IFC environmental, health, and safety guidelines for offshore oil and gas development, IFC environmental, health, and safety guidelines for onshore oil and gas development

[7] Air Quality Impacts of Petroleum Refining and Petrochemical Industries, https://www.researchgate.net/publication/319911732_Air_Quality_Impacts_of_Petroleum_Refining_and_Petrochemical_Industries

Principal Pollutants	Additional Pollutants	Greenhouse Gases
Nitrogen oxides (NOx),	Hydrogen sulfide (H2S);	Carbon dioxide (CO2)
Sulphur oxides (SOx),	Volatile organic compounds (VOC);	Methane (CH4) and Ethane (C2H6)
Carbon monoxide, (CO)	Benzene, ethyl benzene, toluene, and xylenes (BTEX)	Nitrous oxide (N2O)
Particulate Matter (PM)	Polycyclic aromatic hydrocarbons (PAHs)	Global warming potential (GWP) gases (all of the above gases in this column, and Chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF6)[8])
	Mercaptans and mercury	
	Halon and other Chlorofluorocarbon (CFC) gases from fire-fighting and refrigeration systems	

Nitrogen oxides (NOx) include emissions of nitric oxide (NO) and nitrogen dioxide (NO2). Nitrogen dioxide can have adverse effects on human health and the environment. Nitrogen oxides contribute to acid rain, which can lead to the acidification of aquatic and terrestrial ecosystems. It also contributes to the eutrophication of lakes and to the formation of ground-level ozone and fine particulate matter.

Sulfur oxides (SOx) emissions in the atmosphere can have adverse effects on human health and the environment. The SOx emissions released by human activities consist mostly of sulphur dioxides (SO2). Sulphur dioxide can affect respiratory systems of humans and animals and cause damage to vegetation, buildings and materials. It is also a precursor to fine particulate matter (PM2.5) and acid rain.

Carbon monoxide, (CO) is a colourless, odourless, tasteless and poisonous gas. Once inhaled into the bloodstream, it can inhibit the blood's capacity to carry oxygen to organs and tissues, affecting human health.

Particulate Matter (PM). PM usually falls under primary and secondary particulate matter. Primary particulate matter is directly emitted from the source to the atmosphere, and a major source from the petroleum refining industry is the Fluid Catalytic Cracking Unit (FCCU). Secondary particulate matter is mainly formed in the atmosphere from precursor gases like SO2, NOx and VOCs, from photochemical reactions or liquid phase reactions in fog droplets or clouds.

Hydrogen sulphide (H2S) is a colourless gas, soluble in various liquids including water and alcohol. It can be formed under conditions of deficient oxygen, in the presence of organic material and sulphate.

Volatile organic compounds (VOC) are carbon-containing gases and vapours released into the atmosphere. There are hundreds of VOCs that are emitted and that affect the health and the environment. VOCs are primary precursors to the formation of ground-level ozone and particulate matter which are the main pollutants contributing to the formation of smog.

Benzene, toluene, ethylbenzene and xylene (BTEX) compounds occur naturally in crude oil and can be found in sea water in the vicinity of natural gas and petroleum deposits. These chemicals are sweet smelling liquids which rapidly volatize in the air. These compounds are volatile organic compounds

[8] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

(VOCs) that are found in petroleum and petroleum products such as gasoline[9]. The most common sources of exposure to BTEX compounds are from breathing contaminated air, particularly in areas of heavy motor vehicle traffic and petrol stations[10]. The primary man-made releases of BTEX compounds are through emissions from motor vehicles and aircrafts. BTEX compounds are created and used during the processing of petroleum products.

Polycyclic aromatic hydrocarbons (PAHs) are a group of persistent organic compounds, some of which are toxic and/or possible or proven human carcinogens. PAHs occur naturally in coal, crude oil, and gasoline. They also are produced when coal, oil, gas, wood, garbage, and tobacco are burned[11].

Mercury is a natural occurring element and could be present in various stages of oil and natural gas exploration, production and processing. Mercury is not only hazardous to human health and the environment but could also attack process equipment components that have mercury reactive materials, leading to potential catastrophic failure to the plant. The mercury associated with petroleum and natural gas production and processing enters the environment primarily via wastewater, solid waste streams, and air emissions.

Mercaptan, also known as methanethiol, is a foul-smelling gas that is added to natural gas. Since natural gas is colourless and odourless, mercaptan acts as an odorant to make it easier to detect. It is added as a safety measure to ensure that natural gas leaks do not go undetected. It is an organic gas composed of carbon, hydrogen, and sulfur.

Carbon dioxide (CO2) is the primary greenhouse gas emitted through human activities. The main human activity that emits CO2 is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation, although certain industrial processes and land-use changes also emit CO2.

Methane (CH4) is a potent greenhouse gas. Human activities emitting methane include leaks from natural gas systems. Methane's lifetime in the atmosphere is much shorter than carbon dioxide (CO2), but CH4 is more efficient at trapping radiation than CO2. Natural gas and petroleum systems is one of the largest source of CH4 emissions. Methane is emitted to the atmosphere during the production, processing, storage, transmission, and distribution of natural gas. Because gas is often found alongside petroleum, the production, refinement, transportation, and storage of crude oil is also a source of CH4 emissions.

Nitrous oxide (N2O) is a greenhouse gas. Nitrous oxide is emitted when fuels are burned. The amount of N2O emitted from burning fuels depends on the type of fuel and combustion technology, maintenance, and operating practices.

High global warming potential (GWP) gases, which are human-made industrial gases include:

- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulphur hexafluoride (SF6)
- Nitrogen trifluoride (NF3)

3 Status of air quality and air quality management in Kenya

Air pollution is a leading cause of respiratory diseases such as chronic obstructive pulmonary disease (COPD), lung cancer, pulmonary heart disease and bronchitis in Kenya The effects of outdoor air

[9] http://www.gcesystems.com/what-is-btex/
[10] https://environment.des.qld.gov.au/management/non-mining/btex-chemicals.html
[11] https://www.epa.gov/sites/production/files/2014-03/documents/pahs_factsheet_cdc_2013.pdf

pollution are compounded by those of indoor air pollution. Most households use charcoal and firewood for domestic cooking. Indoor air pollution affects both urban and rural populations[12].

According to UNEP Air Quality Catalogue[13] the overall situation with respect to air quality in Kenya, includes the following key air quality challenges:

- Traffic emissions ~~have been~~ were identified as the leading cause of air pollution in major cities in Kenya
- Traffic related emissions are exacerbated by the importation of second-hand vehicles and absence of regular maintenance programs.
- Poor solid waste management i.e. open-burning as a disposal option is also an important source of air pollution
- Majority of the households use kerosene and biomass-based fuel (charcoal) for domestic cooking leading to substantial indoor exposure to air pollution

Furthermore, specific deficiencies were identified with respect to the air quality monitoring system in the country[14]:

- Currently air quality monitoring is limited (any ad hoc monitoring is a response to air pollution complaints; short-time research for academic requirements, no National Air Quality Monitoring Program)
- Ambient Air Quality levels exceed the limits stipulated under the WHO guidelines for some parameters
  Major causes of air pollution are activities in the industrial sector, transport sector, energy sector, waste disposal operations and domestic cooking activities.

With development of the petroleum sector it is critical to prevent similar shortfalls for the industry.

With respect to the climate change challenges – a climate-resilient, low carbon development was established as a national priority for Kenya since it will support Kenya to absorb disturbances and build capacity to adapt to additional stress and change. By pursuing a green economy path and minimising carbon footprints, the country will better deliver constitutional rights to a clean and healthy environment while minimising the country's contribution to global climate change. Measures to address existing climate variability and achieve national development goals should not be at the expense of preparing for future climate change. Measures to address climate change through mitigation and adaptation actions should not compromise the ability of today's generation to achieve people-centered sustainable development.[15]According with the Strategic Environmental and Social Assessment of the Petroleum Sector in Kenya[16] all reasonable attempts should be made to maximize energy efficiency and design facilities to minimize energy use. The overall objective should be to reduce air emissions and evaluate cost-effective options for reducing emissions that are technically feasible. In Kenya, there is no industry specific regulation governing air emissions however the Environmental Management and Co-ordination (Air Quality) Regulations, 2014 are applicable. The provisions in the regulations include: general prohibitions, permissible levels, controlled areas, stationary sources, mobile sources, occupational air quality limits, licensing, methods of measurement, analysis and laboratories, inspection and monitoring and reporting.

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[12] National Environment Policy of Kenya 2013 http://www.environment.go.ke/wp-content/uploads/2014/01/NATIONAL-ENVIRONMENT-POLICY-20131.pdf

[13] https://wedocs.unep.org/bitstream/handle/20.500.11822/17228/Kenya.pdf?sequence=1&isAllowed=y

[14] Ibid

[15] National Environment Policy of Kenya 2013 http://www.environment.go.ke/wp-content/uploads/2014/01/NATIONAL-ENVIRONMENT-POLICY-20131.pdf

[16] Ministry of Energy and Petroleum of Kenya, *Strategic Environmental and Social Assessment of the Petroleum Sector in Kenya*, 2016, http://documents.worldbank.org/curated/en/186991495657679496/pdf/SFG2851-V2-EA-P145234-Box402910B-PUBLIC-Disclosed-5-24-2017.pdf

The responsibility to measure noise levels and air quality rests within the Safety and Health Advisors registered by DOSHS[17]. However, there is no clear mechanism on how these officers should share their findings with NEMA or how to incorporate the Safety and Health audit reports in the environmental audit reports and vice versa. For this reason, NEMA environmental inspectors and Occupational Safety and Health Officers end up duplicating efforts or demanding the same legal requirements in a particular facility[18]. The role of County governments in air pollution control in accordance with the constitution also poses an area of conflict although air quality regulation is yet to be devolved[19].

The powers of the County Governments in Kenya are provided in Articles 191 and 192, and in the fourth schedule of the Constitution of Kenya and the County Governments Act of 2012. In accordance with the Constitution of Kenya, one of the environmental management functions of the County Governments is control of Air and Noise pollution as nuisances. Air emissions and excessive noise levels are major environmental negative impacts that would arise from petroleum development activities across the supply value chain. The Environmental Management and Coordination (Air Quality), Regulations of 2014, are applied in enforcement of air quality standards in Kenya. However, these regulations do not provide petroleum sector air quality standards. In a situation where this regulation would be applied, conflict would arise between NEMA and County Government because the regulation is not yet devolved to County Governments noting that the Constitution of Kenya provides that County government should implement specific national government policies on natural resources and environmental conservation[20].

The following gaps were identified in the Air Quality Standards: *"There is a lack of environmental standards and guidelines for upstream oil drilling and mid-stream processing activities to meet international air quality thresholds."* The following recommendations were provided as a result: emphasize on enforcement and implementation of the following specific regulations to enhance air quality management practices:

- Point Source Air Emissions Prevention and Control Technologies to be adopted by the industry, i.e. on Particulate Matter, SO2, NOx, Ozone depleting substances and Green House Gases.
- Implementation of carbon capture and storage technologies, or installation of protection and enhancement sinks and reservoirs to cut down greenhouse gas emissions.
- Strict implementation and maintenance of a buffer zone of petroleum facility to residential dwellings and storage of highly flammable products based on the current regulations.

This guideline aims to address some of the issues identified in the Strategic Environmental and Social Assessment of the Petroleum Sector in Kenya as well as critical gaps that were identified as part of the gap analysis conducted under project KE-MOE-8370-CS-QCBS "Review of Environmental Regulations & Development of Environmental Inspection & Monitoring Manual for the Petroleum Sector in Kenya".

4 Legal and regulatory frameworks

This section of the guideline aims at providing a list and a description of Kenyan legislation and regulations regulating air emissions as it may apply to petroleum sector. Furthermore, this section contains a detailed list of specific requirements imposed on oil and gas companies.

[17] Ibid
[18] Ibid
19 Ibid
[20] Ibid

4.1 Current legislation and regulations

4.1.1 Environmental Management and Co-ordination Act, 1999 rev 2015(EMCA)

EMCA 1999 as amended is the main law governing environmental protection in Kenya. It provides the legal and institutional framework applicable to all local industries, including the petroleum sector. EMCA 1999 established the National Environment Management Authority (NEMA).

EMCA 1999 contains a broad spectrum of provisions directed at environmental protection, including licensing and permitting; monitoring and enforcement; protection of water bodies; conservation of bio-diversity; environmental restoration; management of hazardous materials; air quality management; effluent discharges; and waste management.

EMCA 1999 is a parent act from which a number of subordinate regulations stem. Due in part to its broad scope, EMCA 1999 fails to provide specific information necessary to give effect to its mandates. Consequently, reaching compliance requires studying EMCA 1999 in concurrence with the relevant subordinate regulation, e.g., the Environmental Management and Coordination (Air Quality) Regulations 2014.

4.1.2 Environmental Management and Coordination (Air Quality) Regulations 2014 (AQR 2014)

This Regulation provides for prevention, control and abatement of air pollution to ensure clean and healthy ambient air. It provides for the establishment of emission standards for various sources such as mobile sources (e.g. motor vehicles) and stationary sources (e.g. industries) as outlined in the EMCA 1999. It also covers any other air pollution source as may be determined by the Minister in consultation with the Authority. Emission limits for various equipment and facilities have been set. The regulations also establish the procedures for the issuance of emissions licenses, measurement of emissions, inspection and monitoring programs, and reporting requirements.

4.1.3 Environmental (Impact Assessment and Audit) Regulations, 2003 [rev 2012]

Environmental Impact Assessment (EIA) is a critical examination of the effects of a project on the environment. Any proponent of a project should conduct an EIA and prepare a report and submit to NEMA. The EIA must be done by a registered and licensed EIA/EA expert by NEMA. The EIA must be conducted before the commencement of the project. The fee payable to NEMA is 0.1% of the project cost. It is therefore an offence to commence any project under schedule II of EMCA without an EIA license. EIA shall be prepared and approved for some petroleum operations.

4.1.4 Petroleum (Exploration, Development and Production) Act, 2019

The Petroleum (Exploration, Development and Production) Act, 2019 (Petroleum Act) is the main law governing upstream petroleum operations in Kenya. It provides the legal and institutional framework applicable to the industry and created Energy and Petroleum Regulatory Authority EPRA). The purpose of ~~U~~EPRA is to exercise general supervision and co-ordination over all matters relating to the upstream petroleum sector, and to be the principal instrument of the government in the implementation of all applicable policies. The Petroleum Act contains a broad spectrum of provisions, including licensing and permitting; revenue sharing; contractual matters; decommissioning; monitoring and enforcement; as well as environment, health and safety-related issues, e.g., waste management, damage compensation, and emergency preparedness. The Petroleum Act is a parent act that was passed in early 2019 will require a number of subordinate regulations to give full force to its provisions.

4.1.5 Energy Act, 2019

The Energy Act, 2019 is the main law governing the energy sector outside of the upstream petroleum operations. It has five main functions to regulate the energy sector by delineating the sectorial functions of the National and County Government; to provide for the promotion of renewable energy; to regulate geothermal energy; to regulate the midstream and downstream operation of the coal and petroleum sectors; and to regulate the production and supply of electricity.

4.1.6 Climate Change Act No. 11 of 2016

The goal of the Act is to provide a regulatory framework for an enhanced response to climate change, and to provide mechanisms and measures to improve resilience to climate change and promote low carbon development. The Act requires public agencies to integrate the National Climate Change Action Plan in their activities, report on sectoral greenhouse gas emissions for the national inventory, put in place and implement sustainability measures, and to report annually all climate change related duties and functions. This Act grants NEMA the authority to monitor, investigate, and report on climate change compliance activities. NEMA is required to report annually on these compliance activities. The Act also creates a Climate Change Fund that will help promote and incentivize actions to prevent and limit climate change.

4.2 Draft laws and regulations

4.2.1 Draft Environmental Management and Coordination (Strategic Assessment, Integrated Impact Assessment and Audit) Regulations, 2018

The overall objective of the Environmental (Strategic Assessment, Integrated Impact Assessment and Audit) Regulations, 2017 is to align it to the Environmental Management and Coordination Act, Cap 387 which was amended in 2015. The Regulations also seek to address emerging issues such as Strategic Environmental Assessments; environmental and social safeguard procedures and Climate Change. This regulation is intended to repeal the Environmental (Impact Assessment and Audit) Regulations, 2003.

5. Gaps in Kenyan legislation

This section aims to identify issues relating to the management of air pollution produced by petroleum operations that are not regulated in Kenyan legislation. These issues comprise the categories: those arising from vagueness or ambiguity in existing regulation; and (2) those arising from the absence of regulation on certain matters. This guideline does not aim to bridge the aforementioned gaps. They are identified for illustrative purposes only. Gaps in Kenyan legislation will be addressed by national authorities, following the corresponding regulatory process.

Furthermore, this section also provides a table with identified instances in which Kenyan law and international best practices are in direct contradiction.

5.1 Gaps

Gaps in Kenyan legislation will be addressed by national authorities, following the corresponding regulatory process.

The list of key gaps includes the following:

- EMCA and its implementing regulation on air quality contain several requirements that only apply explicitly to mineral oil refineries and depots, excluding all other sectors of the industry. The Emissions Limits for Controlled and Non-Controlled Facilities specified in the Third Schedule to the Air Quality Regulations may cover the equipment used at exploration & development sites, but this is not fully clear.
- Furthermore, EMCA and its implementing regulation on air quality contain several requirements that only apply to mineral oil refineries and depots, excluding all other sectors of the industryThese requirements include among others stack specifications, air quality monitoring and record-keeping obligations, among others, matters specific to the upstream oil and gas industry, i.e. flaring and venting, and leak detection.
- Second Schedule of Environmental Management and Coordination (Air Quality) Regulations provides for a list of priority air pollutants. This list is extensive and covers all primary pollutants and greenhouse pollutants. However, pollutants, specific to petroleum sector, such as benzene,

ethyl benzene, toluene, and xylenes (BTEX), polycyclic aromatic hydrocarbons (PAHs), mercaptans and high global warming potential (GWP) gases are not included into the list of pollutants.

- The term “petroleum depots” is not clearly defined in the Air Quality Regulations. This makes it difficult to determine which facilities may be regulated under the existing regulation. It is also unclear if petroleum depots are subject to the same emissions standards as refineries or if a new standard for terminals and transportation hubs should be developed.
- Equally, only petroleum refineries and depots are explicitly mentioned as controlled facilities, which require continuous monitoring as a part of the emission license. Oil and gas exploration, development and production facilities do not explicitly require an emissions license on paper. Similarly, pipelines and related infrastructure facilities, are not listed as controlled facilities, and thus do not require an emissions license. Emissions licenses should be required for the life of the project, through the decommissioning phase.
- The Petroleum Act allows flaring in the case of emergency, production testing, or if the Authority allows, requiring that flaring shall be permitted according to “good petroleum sector practices.” However, explicit clarification on when flaring or venting is allowed according to industry best practices should be specified in the law and/or regulations and guidelines to aid in enforcement and to limit overuse of flaring and venting. The Petroleum Act, EMCA Air Quality Regulations, or future petroleum regulations are the laws and regulations that should be amended to include these provisions.
- The Air Quality Regulations establish emissions limits for hydrocarbons of 20mg/Nm3 from petroleum refineries (a controlled facility) in the Third Schedule of the Regulations. Neither the Air Quality regulations nor the Energy Act provide for any specific parameters for venting and flaring at refineries. The Energy Act, EMCA Air Quality Regulations, or future energy regulations should be amended to include provisions similar to the language in the Petroleum Act for upstream petroleum operations which permit flaring only in emergency situations or during start up or shut down of facilities for maintenance operations.
- The Climate Change Act of 2016 provides for the regulation of greenhouse gases, although establishes no standards or emissions limits. However, provisions are made under AQR 2014 to establish some limits for GHG emissions in Schedule 3 of the AQR 2014.
- Kenyan legislation does not have specific provisions to limit fugitive emissions from petroleum sites, except for controlled facilities, i.e., refineries and depots, which may be required to submit a fugitive emission control plan as part of their emissions license application. However, some general provisions to reduce fugitive emissions are made in Part 6 Schedule 5 of AQR 2014 that would apply to the oil and gas industry. Fugitive emissions specific to the oil and gas industry include leaks vapors from pipelines, equipment seals, valves, flanges, connections, tubing, or tanks. These equipment leaks may be sudden or small and continuous and may occur during normal operations or during loading and unloading operations.
- The Air Quality Regulations requires controlled facilities to include a fugitive emissions control plan as a part of the application for the emissions license. Leak monitoring plans should be developed and included as a requirement for an emissions license. Oil and gas exploration, development, production, storage and transportation facilities should all be required to have an established leak monitoring plan whether or not they are considered controlled facilities.
- The EMCA makes provisions tax rebates and other incentives for companies that invest in plants, equipment and machinery for pollution control. However, there are no tax rebates or tax allocation regimes or plans found in the Petroleum Act encouraging operators to reduce methane emissions.

5.2 Gaps in Kenyan law potentially contradicting international best practices

Citation	Provision	International Best Practice (IBP)	IHSM Recommendation
Eight Schedule, AQR 2014	This schedule provides for emission monitoring reporting	Reporting requirements under IBP are more detailed.	IBP reporting requirements should be considered by NEMA for adoption Recommended practices are provided in S._ 6.2.4.3.1 (h) Reporting requirements_ of this guideline It is noted that Annex 3 of the Guidance Pack for application for Emission Licence for Stationary Sources as per Air Quality Regulations,2014 provides for an Ambient Air Quality Monitoring Report Format ю
S. 32 of AQR 2014	It is required that measurements at the controlled facilities of pollutants are carried out by a laboratory designated by the Authority in order to determine compliance with the prevailing allowed levels of exposure;	This approach may not always work well. Wide range of compliance instruments are allowed under the IBP	NEMA may consider a wider approach in accepting measurements confirming compliance of allowed exposure levels, such as monitoring data collected by companies. Furthermore, several additional approaches can be taken to monitor a specific parameter/emission as detailed further in this guideline.
S. 65 (3) of AQR 2014	The recordkeeping requirement for controlled facilities for emissions records is only two years.	This period is shorter than in most jurisdictions.	Consider imposing an obligation that require upstream and midstream operators to keep records for the period of five years.
First Schedule, AQR 2014	First Schedule of Environmental Management and Coordination (Air Quality) Regulations establishes ambient air quality tolerance limits.	Some pollutants levels do not correspond to current standards stipulated in WHO, IFC guidelines and US National Ambient Air Quality Standards	Consider aligning Kenya's air quality standards for some pollutants in line with limits established in WHO, IFC guidelines. For comparative purpose these limits are summarised in Annex A.
Third Schedule, AQR 2014	Third schedule establishes Air Emission Limits for refineries.	Not all Air Emission Limits for refineries correspond to current limits provided IFC guidelines.	Consider aligning Kenya's air emission limits provided for refineries under Third Schedule with air emission limits established under IFC guidelines. For comparative purpose these limits are summarised in Annex B.
Seventh Schedule, AQR 2014	This schedule makes provisions for acceptable emission control technologies	This list might not be up to date and not representative of best emission control technologies	NEMA my consider on expansion of the list or making more flexible provisions to keep the list up to date

Eleventh Schedule, AQR 2014	This schedule provides for the list of methods of test and measurement of air pollutants	This list might not be up to date and representative of test methods suitable for petroleum sector	NEMA my consider to incorporate flexibility and permit for alternative test and measurement methods, providing they represent best practices. ‘

6 Recommended practices:

6.1 Technologies used for emission reduction and control in the petroleum sector

Projects in the petroleum sector with significant sources of air emissions, and potential for significant impacts to ambient air quality, should prevent or minimize impacts by ensuring that:

- Emissions do not result in pollutant concentrations that reach or exceed relevant ambient quality guidelines and standards by applying Kenya legislated standards, or in their absence, the current WHO Air Quality Guidelines, or other internationally recognized sources;
- Emissions do not contribute a significant portion to the attainment of relevant ambient air quality guidelines or standards.
- At facility level, impacts should be estimated through qualitative or quantitative assessments by the use of baseline air quality assessments and atmospheric dispersion models to assess potential ground level concentrations. Local atmospheric, climatic, and air quality data should be applied when modeling dispersion, protection against atmospheric downwash, wakes, or eddy effects of the source, nearby structures, and terrain features. The dispersion model applied should be internationally recognized, or comparable21.

Emissions from point sources should be avoided and controlled according to good international industry practice, depending on ambient conditions, through the combined application of process modifications and emissions controls. Projects with potentially significant fugitive sources of emissions should establish the need for ambient quality assessment and monitoring practices.

The current Kenya key regulatory requirements related to emission reduction and control measures are summarized in the table below for the ease of reference. It should be noted that most of these requirements are of generic nature and not specific to petroleum sector.

However, where these requirements are applicable to petroleum sector, companies shall comply with such requirements or seek appropriate deviations from NEMA and relevant authorities by adopting international best practices or requirements applied in their countries of origin to assure continuation of rights granted under the terms of petroleum contracts.

Requirement	Control measure	Reduction measure
STATIONARY SOURCES		
Air pollution control systems The ***control systems*** set out in the **Seventh Schedule** shall be used by all persons whose operations cause or are likely to cause the ***emission of pollutants in excess of the limits*** set out in the **Third Schedule**. [S.16(1) AQR 2014] The ***emission reduction measures*** set out under **Part IV of the Fifth schedule** shall be applied in the operation of burners. [S16(3) AQR 2014]	**Seventh Schedule - List of Acceptable Emission Control Technologies** • **Particulate Matter** - Mechanical collectors (dust cyclones, multicyclones), Electrostatic precipitators Fabric filters (baghouses), Particulate scrubbers • **Nitrogen Oxides (NOx)** * Low NOx burners Selective catalytic reduction (SCR), Selective non-catalytic reduction (SNCR), NOx scrubbers, Exhaust gas recirculation, Catalytic converter • **Volatile Organic Compounds (VOC), hydrocarbons**- Adsorption systems, such as activated carbon, Flares, Thermal oxidizers,	**Part IV of the Fifth schedule** establishes Emission Reduction Measures of Dark Smoke from Chimneys (please see specific measures provided in the regulation)

[21]IFC Environmental, Health, and Safety Guidelines, https://www.ifc.org/wps/wcm/connect/532ff4804886583ab4d6f66a6515bb18/1-1%2BAir%2BEmissions%2Band%2BAmbient%2BAir%2BQuality.pdf?MOD=AJPERES

	Catalytic oxidizers, Biofilters. Absorption (scrubbing). Cryogenic condensers • Sulphur Oxides (SOx) - Wet scrubbers, Dry scrubbers, Flue gas desulphurization • **Carbon Oxides** - Thermal oxidizers • **Hydrogen Sulphides** - Absorption (scrubbing) • **Hydrogen Chloride** - Dry Scrubbers, Adsorption systems, such as activated carbon • **Dioxins & Furans Cyclone** - Electrostatic precipitator. Bag filter. Wet scrubber, Quenching & subsequent wet scrubber, Catalytic oxidation (selective catalytic reaction), Catalytic bag filter, Dry absorption in resins (carbon particles dispersed in a polymer matrix), Entrained flow reactor with added activated carbon or coke/lime or limestone solutions and subsequent fabric filter, Fixed bed or circulating fluidized bed reactor, adsorption with activated carbon or open hearth coke • **Metals (Hg, Pb,)**-Sorbent Injection Technology Electro-Catalytic Oxidation (ECO) K-Fuel • **Any other technology approved by the Authority from time to time**	
Fugitive emission reduction measures A fugitive emission control plan may require the employment of ***measures or operating procedures*** indicated in Part VI of the Fifth Schedule. [S26 AQR 2014]		Part VI of the Fifth Schedule - Measures or operating procedures to control fugitive emissions. (please see specific measures provided in regulations)
MOBILE SOURCES		
Control of vehicular emissions Every operator or owner of a mobile emission source including road, rail, air, marine and inland water transport and conveyance equipment, shall control the emission of priority air pollutants set out in the **Second Schedule**. [S 25.2 AQR 2014]		
Emission reduction measures. In order to meet the emission standards stipulated by the Bureau, the owner or operator of a mobile emission source may use any of the emission reduction measures specified under the **Twelfth Schedule** or any other technology acceptable to the Authority. [S 27 AQR 2014]		**Twelfth Schedule**

This section aims at summarizing currently available best technologies, techniques, methods, etc. applied in petroleum sector globally, that are aimed at reducing air emissions of pollutants from petroleum operations.

Techniques provided in this section are indicative and their application may result in reduction or mitigation of emissions from development and production operations. Emission reduction techniques described herein can be applied to existing operations or considered as mitigation measures to be applied in planning and analysis of potential future development.

The list of techniques is neither prescriptive nor exhaustive so that petroleum sector of Kenya should be able to continue developing and implementing the new novel techniques in coordination with NEMA and other competent state bodies.

The generic high-level list of actions to be reviewed and adopted by petroleum companies consists of the following[22]:

1. Design and operate to minimize air emissions.
2. Use regular preventative maintenance and monitoring procedures.
3. Install and maintain catalytic converters.
4. Use low NOx burners.
5. Convert engines to lean-burn.
6. Maintain and run all engines to be the most fuel efficient.
7. Install pre-combustion chambers on engines.
8. Install electronic ignition systems on engines.
9. Use natural gas engines instead of engines fueled by diesel or other fuels.
10. Tighten connections and replace packing to minimize leaks and fugitive emissions.
11. Reduce emissions of unburned hydrocarbons in new facility design (e.g., route emissions to flare, route dehydrator still emissions to first stage compression, use electric drivers for compressors, use shorter piping runs with fewer flanges, use welded rather than screwed or bolted fittings).
12. Reduce horsepower demands to reduce emissions.
13. Maintain tank thief hatch seals.
14. Route dehydrator still emissions to reboiler, firebox, first stage compression, or flare.
15. Lower glycol circulation rate - avoid over dehydrating (vapor recovery).
16. Eliminate use of sparge or stripping gas in dehydrators.
17. Buy solvents and liquid chemical in bulk and keep containers covered.
18. Buy less volatile solvents and liquid chemicals.
19. Use dust control techniques at facilities.
20. Eliminate the use of halon fire extinguishing materials.
21. Revise test procedures so halon is not released.
22. Use waste heat recovery opportunities where possible.
23. Use vented or flared gas as fuel.
24. Collect vented or flared gas, compress, and sell as product or use to power facilities, where possible.

6.1.1 Specific emission reduction techniques for upstream oil and gas

The following table provides for a summary of techniques aimed at reducing emissions in the upstream oil and gas industry[23]. These techniques shall be considered and implemented where relevant and practical by petroleum companies and their contractors to mitigate risks of air pollution in Kenya.

Ibid.

[23] Emission Reduction Techniques for Oil and Gas Activities https://www.fs.fed.us/air/documents/EmissionReduction-072011x.pdf

No	Emission Reduction Technique	Emissions reduced	Benefits:	Application	Limitations
Transportation					
1	**Traffic Reduction** - reducing trucking and service traffic can reduce associated dust and tailpipe emissions.	• NOx from tailpipe emissions. • VOC, CO, and CO2 from tailpipe emissions. • PM10 and PM2.5 from road dust and construction activities.	• Reduces on-road emissions from exhaust. • Reduces entrained particulate matter as road dust. • Reduced road wear. • Improved safety.	• At least to some extent, to most projects. • During development when coordinated crews are working rotating shifts.	• Requires administrative authority otherwise will be limited as a voluntary program. • Limits to the minimum number of trips required for tasks including safety-related activities and essential maintenance.
2	**Directional Drilling of Multiple Wells Per Pad** - to drill multiple wells from a well pad, although directional drilling can also occur on a single-well pad	• NOx from tailpipe emissions. • VOC, CO, and CO2 from tailpipe emissions • PM10 and PM2.5 from road dust and construction activities. • Future reduction of VOC due to consolidated production facilities by making the capture of VOC and CH4 more economically viable.	• May decrease vehicle traffic; i.e., reduce road and pad construction related dust and emissions, • Reduces road network. • May reduce truck traffic dust and emissions during production. • Facilitates use of consolidated production facilities, making controls more efficient and cost-effective on VOC and NOx emissions.	• In most development scenarios, though it is sometimes used in exploratory developments where access is limited due to terrain or minimal ground disturbance is desired	• NOx, CO, and CO2 and other engine emissions from drill rigs are much larger per engine than those associated with vehicle traffic. Hence, increase in drill time from directional drilling may result in a short-term emissions increase, even if emissions from vehicle traffic decrease in the long term. This may not work in exploration phase of development, because the field has not yet been delineated. • In some areas, the geologic structures are not suited to directional drilling. • Total air emissions might actually increase as a result of directional drilling due to the increase in true depth, i.e., greater distances drilled, greater drill times, and increased overall energy use.

					• Technical, down-hole limits on directional drilling remain in spite of tremendous advances.
3	**Centralized Water Storage and Delivery** - centrally stored water piped to the well pads and fracturing facilities through a temporary, plastic, surface line	• NOx from tailpipe emissions. • VOC, CO, and CO2 from tailpipe emissions. • PM10 and PM2.5 from road dust.	• Reduces number of truck trips for hauling water. • Decreases dust from road traffic. • Reduced tailpipe emissions. • Less disturbance of wildlife	• Can be used for developed and producing wells. • Can be applied to individual or consolidated facilities	• May not be feasible in some terrain. • May not be feasible if wells are too far apart. • Emissions occur during construction of centralized facility. • May not be feasible if the collection point is too far away.
4	**Offsite Centralization of Production & Use of Liquids Gathering Systems** - collect and pipe produced fluids from remote well location to acentralized production and collection facility situated more closely to a major county or state highway	• NOx from tailpipe emissions. • VOC, CO, and CO2 from tailpipe emissions. • PM10 and PM2.5 from road dust. • •VOC from the absence of venting tanks at well pads.	• Creates fewer emission sources and consolidates control of emissions. • Reduces haul truck trips and decreases associated dust and tailpipe emissions. • Increased economic viability of capturing flash emissions and returning them to market rather than venting.	• In fields that produce significant quantities of natural gas liquids. • Where construction of pipelines is feasible and permissible.	• May not be feasible in some terrain conditions. • May not be feasible if wells are too far apart. • Concentrated emissions occur during construction of centralized facility. • Requires installation and maintenance of pipelines.
5	**Telemetry and Well Automation** - using telemetry, rather than daily visits by operators, to remotely monitor and control production.	• NOx from tailpipe emissions. • VOC, CO, and CO2 from tailpipe emissions. • PM10 and PM2.5 from road dust.	• Reduces truck trips and engine emissions. • Decreases associated dust emissions. • Increased safety.	• At least to some extent, can be applied to most projects. • Subject to availability of licensed spectrum and bandwidth.	• May require application-specific development or adaptation. • Training required. • Specialized servicing.
6	**Dust Suppression with Water –** reduce fugitive	• PM10 and PM2.5 from road dust.	• Emission reduction; can greatly reduce dust near	• Unpaved and partially paved roadways.	• Most effective with low traffic. • Lasts only hours; requires frequent

	dust from vehicle traffic by applying water to unpaved roadways.		roadway and, to some extent, up to several • miles away from roadway. • May reduce road wear somewhat. • Improved safety for drivers. • Low initial cost.	• At least to some extent, can be applied to most projects.	applications and maintenance. Availability of water in arid areas. • Tailpipe emissions from vehicles making applications. • Requires administrative authority for implementation and enforcement.
7	**Dust-Suppressant Mixtures** - Reducing fugitive dust from vehicle traffic by applying dust suppressants	• PM10 and PM2.5 from road dust.	• Emission reduction; can greatly reduce dust near roadway and, to some extent, up to several miles away from roadway. Reduced road wear. • Improved safety for drivers. • Moderate initial cost. • Lasts up to a year. Good for low-traffic roads.	• Unpaved and partially paved roadways. • At least to some extent, to most projects.	• Higher cost than water. • Requires periodic re-treatment and maintenance. • Tailpipe emissions from vehicles making applications. • Possible migration of treatment materials. • Requires administrative authority for implementation and enforcement. Check with local authorities regarding the allowable use of specific dust suppressants.
8	**Road Sealing and Surfacing - r**educing fugitive dust from vehicle traffic by sealing or paving roadways using chip-seal, asphalt, or other road surfaces.	• PM10 and PM2.5 from road dust.	• Emission **reduction**; can greatly improve air quality near roadway and, to some extent, up to several miles away from roadway. • Significantly reduced road wear and erosion of roadbed. • Improved safety for drivers. • Effective on high-traffic roads. • Can withstand traffic for several years.	• Unpaved or partially paved roadways. • Where construction of permanent, paved roadways is feasible and permissible.	• High or very high initial cost; more cost-effective for roads with higher average daily traffic. • Possible increase in multi-use traffic, with corresponding increases in tailpipe emissions. • Fragmentation of the landscape.
9	**Administrative Controls on Roadways** - Using reduced	• PM10 and PM2.5 from road dust. • Tailpipe emissions including NOx,	• Emission reduction. • Reduced road wear.	• At least to some extent, can be applied to most projects.	• Requires authority to post speed limits.

	vehicle speeds to decrease fugitive dust.	VOC, CO, and CO_2 due to improved fuel economy.	• Improved safety	• Unpaved and partially paved roadways. • On roads with high traffic and high dust potential.	• Requires effort to implement and enforce.
Air Resource Emission Reduction Techniques Drilling Phase					
1	**Cleaner Diesel Power** - reducing engine emissions by moving toward cleaner diesel (or compression-ignition) engines	• NOx, CO, PM10, and PM2.5. • Co2 • Hydrocarbons.	• Uses engines manufactured to meet standards. • Engines are to be available on a regulatory schedule.	• Generator sets where diesel-electric drilling is to be used. • Small and medium wellhead engines, if in use. • May be considered for applications for permits to drill or records of decision; states typically do not regulate mobile-source drill rig engines.	• Cost of purchasing newly manufactured engines meeting current emission standards. • Drillers operate under contract to applicants or field operators; any specification of engine type must flow through a contract.
2	**Natural Gas Power -** reducing engine emissions by using engines and generator sets fueled with natural gas	• NOx, CO, SO_2, PM10, and PM2.5. • Hydrocarbons.	• Low emission characteristics. • Fuel may be available on-site, following suitable processing.	• In lieu of diesel-electric generator sets, as indicated by comparison of emission benefits and economics. • Compressor stations. • Small and medium wellhead engines, if in use.	• Requires selection of correct engines to meet power requirements. • Cost of capital equipment. • Drillers operate independently of applicants or field operators
3	**Well Completions – Flaring** - Flaring of natural gas in order to avoid venting and prevent safety hazards	• CH_4, greenhouse gas emissions. • To some extent, VOC.	• Avoids extensive venting, which should be prohibited or limited by regulation. • May cheaply and directly eliminate safety hazards posed by natural gas under pressure.	• Where venting is impracticable (e.g., to prevent forceful venting of natural gas under emergency upset conditions) or prohibited (e.g., by state regulation). • Where permitted, to	• Emits NOx, CO, and PM2.5. • CO_2 (a less potent greenhouse gas than CH_4). • Possibly emits volatile organic compounds that remain after incomplete combustion. • Wastes valuable natural gas resources.

				flare natural gas considered to be economically irrecoverable at condensate wells or oil wells (an increasingly atypical circumstance).	• Prohibited in some circumstances and jurisdictions.
4	**Reduced-Emission Well Completions** - Using "green completions" to recapture a significant portion of product that would have been vented or flared. This type of device separates gas, sand, and water24.	• CH_4 and VOC (relative to venting). • NOx, CO, and PM2.5 (relative to flaring).	• Reduces CH_4 & VOC emissions. • Recovers product for sale. • Improved overall safety at the well site. • Recovers water for reuse.	• Where safety permits recovery of gas (e.g., green completions are not inherently suitable to catastrophic releases of pressure such as blowouts). • Where economics point toward using the technology. • Where a sales line or other gas line with sufficient capacity is available to receive produced gas. • Where natural gas liquids or, in some cases, crude oil accompany produced natural gas.	• Cost. • Requires adequate reservoir pressure. • Pressure of the gas must not exceed the rating of the sand trap or separator vessels. • Gas must meet pipeline specifications.
Air Resource Emission Reduction Techniques Production Phase					
1	**Solar Power** - Using chemical pumps and well monitoring telemetry powered by solar panels.	• NOx from tailpipe emissions. • VOC, CO, and CO_2 from tailpipe emissions. • PM10 and PM2.5 from road dust.	• Reduces truck trips, engine emissions, and CH_4 from gas pneumatic pumps. • Silent operation.	• At least to some extent, can be applied to most projects. • At unshaded well and battery locations.	• Cost of capital equipment. • Requires adequate number of panels to meet power requirements. • Batteries, other electric storage, or alternative power sources needed during darkness.

[24] • High-pressure vessel separates sand from field gas. • Gas vessel separates gas from water used for hydrologic fracturing. • Gas is routed to sales line. • Sand dumps to drill pit manually. • Water dumps to media tanks automatically. • Water is filtered and reused for future fracturing jobs, https://www.fs.fed.us/air/documents/EmissionReduction-072011x.pdf

2	**Electric Power - using** electricity from the nation's power grid is typically cleaner than using onsite diesel or natural gas engines to power drill rigs, compressors, and pumping units.[25]	• NOx from tailpipe emissions. • VOCs, CO, and CO2 from tailpipe emissions. • PM10 and PM2.5 from road dust.	• Standard rates available from utility. • Eliminates in-field emissions from engines replaced by electric motors. • Eliminates emissions from vehicles hauling product (e.g., condensate trucks). • Reduces CH4 from gas pneumatic pumps. • May reduce overall traffic for maintenance-related trips. • Silent operation.	• Wherever grid power is available.	• Proximity to the grid. • Increased load on grid with increased emissions at electric generating units. • Power loss in transmission (line loss) proportional to the square of the current. • Permitting requirements for new service.
3	**Enclosed tanks** storing to reduce fugitive VOC emissions.	• CH4, VOC, hazardous air pollutants	• Containment and control of product. • Improved safety and wildlife protection.	• Projects involving storage of liquid hydrocarbons.	• Construction, including access road. • Cost of tank, fittings, and installation. • Operation and maintenance costs.
4	**Vapor Recovery Units** - reduces vented emissions of VOC and recovers valuable hydrocarbon vapors for sale or use on site[26].	• CH4, VOC, hazardous air pollutants, and	• Recovery of product otherwise lost. • Potential improvements in fire safety.	• Projects involving storage of liquid hydrocarbons. • On storage tanks, where pressures of hydrocarbons are at or near atmospheric pressure. • Where oxygen can be excluded or explosive mixtures otherwise avoided.	• Cost-effectiveness varies with volume of hydrocarbons that can be recovered. • Must be correctly engineered for safe operation.
5	**Hatches, Seals, and Valves** use and maintenance	• CH4, VOC, hazardous air pollutants	• Well-established technology. • Moderate cost.	• Projects involving storage of liquid hydrocarbons.	• Must be selected appropriately for application.

[25] However, overhead power lines may have wildlife or visual impacts

[26] Vapor recovery can readily capture 95 percent of the vapors that would be emitted from tanks if left uncontrolled, and capture efficiencies of virtually 100 percent are possible.

	to minimize VOC emissions.[27]			On storage tanks, where pressures of hydrocarbons are at or near atmospheric pressure. • Where oxygen can be excluded or explosive mixtures otherwise avoided.	• Will release hydrocarbon vapors at designed pressure and temperature.
6	**Controls for Compressor Engines** - improve emission controls on new or existing engines using a combination of techniques.[28]	• NOx, SO2, CO, and CO2. • Some PM2.5.	• Moderate cost, depending upon application and options selected.	• Projects involving natural gas compression • Include control package as an option on new engines. • Retrofit on existing engines. • May be subject to regulatory approval by state	• Availability by engine type and year of manufacture. • May require testing to confirm target emission rate is achieved.
7	**Selective Catalytic Reduction** works by injecting diesel exhaust fluid (DEF, a mixture of water and urea) into the exhaust	• NOx • PM2.5 and hydrocarbons (if diesel particulate filter is included).	• Proven capability to reduce emissions. • Feasibility of retrofitting.	• Exhaust streams (on large engines, particularly where loads are steady or predictable). • Where NO emissions are of concern.	• Cost. • Availability by for specific application. • May require testing to confirm target emission rate is achieved. • May be subject to regulatory approval by state.
8	**Dry Seals in Centrifugal Compressors** that emit less methane and have lower power requirements	• CH4 • VOC	• Feasibility of retrofitting.	• Natural gas compression where centrifugal compressors are in use.	• Relatively specialized applications
9	**Packing Seals for**	• CH4 • VOC	• Feasibility of retrofitting.	• Natural gas compression where reciprocating-	• Additional operational burden due to more

[27] In order to minimize emissions and in addition to selecting appropriate hatches, seals, and valves relative to tank design, it is important to establish optimum pressure settings for this equipment.

[28] Techniques such as: closed loop engine control, selective catalytic reduction (covered as a stand-alone technique in section 3.7), system-installed power supply (solar powered, battery powered), ultra-low sulfur diesel, diesel particulate filter, after burner, and/or other new technologies.

	Compressor Rods29		• Proven capability to reduce emissions.	rod compressors are in use	frequent maintenance. • Cost.
10	**Reduced-Emission Pneumatic Systems**	• CH_4. • VOC	• Feasibility and ease of retrofitting with fairly quick cost recovery. • Product recovery. • Proven capability to reduce emissions.	• Fields using natural gas in pneumatic controls. • Where conversion to air-actuated or electric controls is economically infeasible.	• Accessibility of components. • Continues to use natural gas.
11	**Plunger Lift Systems and Automated Systems in Gas Wells**	• CH_4 • VOC	• Greater recovery of product. • Operation and maintenance may be simplified. • Potentially improved safety.	• Typically in mature gas wells. • Where down-well accumulation of liquids tends to compel blowdown to restore flow of natural gas.	• Cost-effectiveness. • Relatively specialized application
Monitoring and Maintenance					
1	Directed Inspection and Maintenance and Infrared Leak Detection (DI&M)[30]	• CH_4 • VOC	• Detects emissions by remote sensing. • Ease of use following minimal training.	• Most projects involving hydrocarbon production and treatment. • In order to detect leaking process components, including valves, flanges, and connections. • Sealing mechanisms, such as on reciprocating rods and pump seals. • Hatches and seals on tanks	• No direct quantification of emission rates. • Most effective when used in a structured program requiring oversight and management. • Cost of purchase and repair of instrumentation.
	Air Quality Monitoring[31]	• Indirectly, emissions of any	• Gives knowledge of concentrations	• Large projects or project areas	• Cost.

[29] The packing seals of reciprocating-rod compressors leak some gas by design. Emissions from rod packing can be reduced by the economic replacement of rod packing at frequent intervals as: newly installed packing may leak 60 cubic feet per hour. Worn packing has been reported to leak up to 900 cubic feet per hour.

[30] Fugitive gas leaks can be reduced by implementing a DI&M Program which identifies and cost effectively fixes fugitive gas leaks using: Leak Detection, Infrared Camera, Organic Vapor Analyzer, Soap Solution, Ultrasonic Leak Detectors, Measurement, Calibrated Bagging, Rotameters, High Volume Sampler

[31] Monitoring current and modeling future air quality conditions. Designing emission control strategies. Reviewing monitoringg data and adapting to findings: aadjusting development rates, timing, and places of development; refining mitigation measures

		pollutant of concern which can be monitored.	and trends in the ambient air. • Produces information that can be shared with the public. • Supports air dispersion modeling efforts.	where adequate funding can be arranged. • At a location that is representative under the monitoring objective(s). • Where land access, possibly long-term, can be gained. • Where electric power is available, unless passive sampling or monitoring using low-power equipment can suffice. • In the "ambient air," as defined for regulatory purposes, if required.	• Time required in order to collect and report data. • Difficulty of meeting expectations of data users. • Does not directly control or reduce emissions.

Additional reference documents that provide for technologies, techniques and standards for emission control and reduction in the upstream petroleum sector are summarized in Annexes C and D.

6.1.2 Greenhouse reduction measures for downstream industry

The following table summarizes emerging and available technologies for reducing greenhouse gas (GHG) emissions predominantly from the petroleum refining industry. These techniques shall be considered and implemented where relevant and practical by petroleum companies and their contractors to mitigate risks of air pollution in Kenya.[32]

No	GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Demonstrated in Practice?
Energy Efficiency Programs and Systems				
1	Energy Efficiency Initiatives and Improvements	Benchmark GHG performance and implement energy management systems to improve energy efficiency, such as: ▪ improve process monitoring and control systems ▪ use high efficiency motors ▪ use variable speed drives ▪ optimize compressed air systems ▪ implement lighting system efficiency improvements	4-17% of electricity consumption	Yes
Stationary Combustion Sources				
Steam Generating Boilers				

[32] https://www.epa.gov/sites/production/files/2015-12/documents/refineries.pdf

1	Systems Approach to Steam Generation	Analyze steam needs and energy recovery options, including: ▪ minimize steam generation at excess pressure or volume ▪ use turbo or steam expanders when excesses are unavoidable ▪ schedule boilers based on efficiency		Yes
2	Boiler Feed Water Preparation	Replace a hot lime water softener with a reverse osmosis membrane treatment system to remove hardness and reduce alkalinity of boiler feed.	70-90% reduction in blowdown steam loss; up to 10% reduction in GHG emissions	Yes
3	Improved Process Control	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air. Low excess air levels may increase CO emissions.	1-3% of boiler emissions	Yes
4	Improved Insulation	Insulation (or improved insulation) of boilers and distribution pipes.	3-13% of boiler emissions	Yes
5	Improved Maintenance	All boilers should be maintained according to a maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Additionally, fouling on the fireside of the boiler and scaling on the waterside should be controlled.	1-10% of boiler emissions	Yes
6	Recover Heat from Process Flue Gas	Flue gases throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economizer to preheat the boiler feed water	2-4% of boiler emissions	Yes
7	Recover Steam from Blowdown	Install a steam recover system to recover blowdown steam for low pressure steam needs (e.g., space heating and feed water preheating)	1-3%	Yes
8	Reduce Standby Losses	Reduce or eliminate steam production at standby by modifying the burner, combustion air supply, and boiler feedwater supply, and using automatic control systems to reduce the time needed to	Up to 85% reduction in standby losses (but likely a small fraction of facility total boiler emissions)	Yes
9	Improve and Maintain Steam Traps	Implement a maintenance plan that includes regular inspection and maintenance of steam traps to prevent steam lost through malfunctioning steam traps.	1-10% of boiler emissions	Yes
10	Install Steam Condensate Return Lines	Reuse of the steam condensate reduces the amount of feed water needed and reduces the amount of energy needed to produce steam since the condensate is preheated.	1- 10% of steam energy use	Yes
Process Heaters				
1	Combustion Air Controls Limitations on Excess air	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	1-3%	Yes
2	Heat Recovery: Air Preheater	Air preheater package consists of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convective section exchange heat with the incoming combustion air. If the original heater is natural draft, a retrofit requires conversion to	10-15% over units with no preheat.	Yes

		mechanical draft. ***May increase NOx emissions***		
Combined Heat and Power				
1	Combined Heat and Power	Use internally generated fuels or natural gas for power (electricity) production using a gas turbine and generate steam from waste heat of combustion exhaust to achieve greater energy efficiencies		Yes
Carbon Capture				
1	Oxy-combustion	Use pure oxygen in large combustion sources to reduce flue gas volumes and increase CO2 concentrations to improve capture efficiency and costs		No
2	Post-combustion Solvent Capture	Use solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, for separation of CO2 in post-combustion exhaust streams		Yes
3	Post-combustion membranes	Use membrane technology to separate or adsorb CO2 in an exhaust stream		No
Fuel Gas System and Flares				
Fuel Gas System				
1	Compressor Selection	Use dry seal rather than wet seal compressors; use rod packing for reciprocating compressors		Yes
2	Leak Detection and Repair	Use organic vapor analyzer or optical sensing technologies to identify leaks in natural gas lines, fuel gas lines, and other lines with high methane concentrations and repair the leaks as soon as possible.	80-90% of leak emissions;	Yes
3	Sulfur Scrubbing System	Evaluate different sulfur scrubbing technologies or solvents for energy efficiency		Yes
Flares				
1	Flare Gas Recovery	Install flare gas recovery compressor system to recover flare gas to the fuel gas system		Yes
2	Proper Flare Operation	Maintain combustion efficiency of flare by controlling heating content of flare gas and steam or air-assist rates		Yes
3	Refrigerated Condensers	Use refrigerated condensers to increase product recovery and reduce excess fuel gas production		Yes
Cracking Units				
Fluid Catalytic Cracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)				
1	Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the FCCU regenerator exhaust		Yes
2	High-Efficiency Regenerators	Use specially designed FCCU regenerators for high efficiency, complete combustion of catalyst coke deposits		Yes
Hydrocracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)				
1	Power/Waste Heat Recovery	Install or upgrade power recovery to recover power from power can be recovered from the pressure difference between the reactor and fractionation stages		Yes

2	Hydrogen Recovery	Use hydrogen recovery compressor and back-up compressor to ensure recovery of hydrogen in process off-gas		Yes
Cooking Unit				
Fluid Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)				
1	Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the fluid coking unit exhaust		Yes
Flexicoking Units (see: Stationary Combustion Sources; Fuel Gas System and Flares)				
Delayed Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)				
1	Steam Blowdown System	Use low back-pressure blowdown system and recycle hot blowdown system water for steam generation		Yes
2	Steam Vent	Lower pressure and temperature of coke drum to 2 to 5 psig and 230°F to minimize direct venting emissions	50 to 80% reduction in direct steam vent CH_4 emissions	Yes
Catalytic Reforming Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)				
Sulfur Recovery Units				
1	Sulfur Recovery System Selection	Evaluate energy and CO_2 intensity in selection of sulfur recovery unit and tail gas treatment system and a variety of different tail gas treatment units including Claus, SuperClaus® and EuroClaus®, SCOT, Beavon/amine, Beavon/Stretford, Cansolv®, LoCat®, and Wellman-Lord		Yes
Hydrogen Production Units				
1	Hydrogen Production Optimization	Implement a comprehensive assessment of hydrogen needs and consider using additional catalytic reforming units to produce H_2		Yes
2	Combustion Air and Feed/Steam Preheat	Use heat recovery systems to preheat the feed/steam and combustion air temperature	5% of total energy consumption for H_2 production	Yes
3	Cogeneration	Use cogeneration of hydrogen and electricity: hot exhaust from a gas turbine is transferred to the reformer furnace; the reformer convection section is also used as a heat recovery steam generator (HRSG) in a cogeneration design; steam raised in the convection section can be put through either a topping or condensing turbine for additional power generation		Yes
4	Hydrogen Purification	Evaluate hydrogen purification processes (i.e., pressure-swing adsorption, membrane separation, and cryogenic separation) for overall energy intensity and potential CO_2 recovery.		Yes
Hydrotreating Units (see also: Hydrogen Production Units; Sulfur Recovery Units)				
1	Hydrotreater Design	Use energy efficient hydrotreater designs and new catalyst to increase sulfur removal.		Yes
Crude Desalting and Distillation Units				
1	Desalter Design	Alternative designs for the desalter, such as multi-stage units and combinations of AC and DC fields, may increase efficiency and reduce energy consumption.		Yes

2	Progressive Distillation Design	Progressive distillation process uses as series of distillation towers working at different temperatures to avoid superheating lighter fractions of the crude oil.	30% reduction in crude heater emissions; 5% or more refinery-wide	Yes
Storage Tanks				
1	Vapor Recovery or Control for Unstabilized Crude Oil Tanks	Consider use of a vapor recovery or control system for crude oil storage tanks that receive crude oil that has been stored under pressure ("unstabilized" crude oil)	90-95% reduction in CH4 from these tanks	Yes
	Heated Storage Tank Insulation	Insulate heated storage tanks		Yes

Oil and Gas companies operating in Kenya are required to keep themselves informed, updated and required to implement best practices aimed at reducing of air emissions at all phases of petroleum operations.

It is the responsibility of the company to demonstrate to NEMA that such practices are selected, implemented and adhered to as part of the approval process established in Kenyan legislation.

6.2 Procedure for measurement of emissions and ambient air quality standards levels in the petroleum sector

6.2.1 Objectives of emission monitoring and measurement

Monitoring may be performed for any petroleum activities that have been identified as having potential environmental impacts. Environmental monitoring can involve direct or indirect measurement of emissions, discharges, and resource use applicable to operations and process parameters, as well as of impacts on environmental receptors. Monitoring activities are undertaken throughout facility or project operational life, i.e. from before activities commence to establish baselines, as well as during, development, production and decommissioning.

Monitoring provides insight to support management and ultimately reduce impacts. Appropriate environmental monitoring and control equipment can, in some cases, allow operational improvements and assist in checking compliance with permit conditions while activities are underway.This section of the guideline aims to provide a guidance to petroleum companies for measurement of air emissions from their operations as part of the monitoring process to ensure these are:

1. correct –emissions measurements are of high quality and free from errors;
2. representative– spatial/temporal variations and the extent of human exposure are considered
3. consistent – air emission data is recorded, analysed, processed, reported and archived following best-practice principles
4. accessible – users of air emission data have quick and easy access to methods, procedures and new developments.

6.2.2 Air emission measurement and monitoring requirements stipulated in Kenya legislation

AQR 2014 makes provisions related to emission measurement and reporting which in most cases are not specific to the upstream petroleum sector. For the ease of reference these requirements are summarized in the table below along with the air quality monitoring requirements. Companies are responsible to identify if their facilities or activities fall under the terms of the regulation in order to comply with current regulatory requirements, unless the waiver is granted by the Authority.

Annex E provides for a comparative table of measurements standards applicable in Kenya and in accordance with international best practice.

Despite that some requirements are of a generic nature, where such requirements are applicable to petroleum sector, companies shall comply with such requirements or seek appropriate deviations from

NEMA and relevant authorities to assure continuation of rights granted under the terms of petroleum contracts.

Requirement	Facilities/Emissions/Air Quality	Responsible Person	Test Methods/Additional measures
<u>Exposure to hazardous substances</u>. An owner or occupier of a controlled facility shall-(c) ensure that **measurements of pollutants are carried out by a laboratory designated by the Authority** in order to determine compliance with the prevailing allowed levels of exposure; (d) ensure that **record of measurements** carried out under paragraph (c) are reported to the Authority on a quarterly basis; and (e) take **exposure reduction measures** recommended under **Part IX of the Fifth Schedule**. [S.32 (c) (d) (e) AQR, 2014]	• controlled facility • <u>Fifth Schedule Part IX</u>:-Occupational Air Quality Guidelines	• An owner or an occupier	Measurements done by laboratory designated by the Authority Methods of test and measurement of air pollutants provided in **<u>Eleventh Schedule</u>** This schedule lists Kenyan's standards of methods of test and measurement of air pollutants Please refer to the list of standards.
Application procedure for provisional emission licence (1) An owner or operator of a controlled facility shall apply for a provisional emission license (2) An application shall be considered complete when the following requirements are satisfied- (b) the licence application is accompanied by a **compliance plan** that indicates the proposed activities and the schedule for bringing the facility into compliance where – (i) *the expected emissions from any source or activity in the application are likely to exceed any applicable emission standard or target;* *(ii) any expected emissions from the facility are based on dispersion modeling, are found to be likely to exceed any ambient air quality standard; or* *(iii) any expected ambient air quality measurements at required monitoring locations exceeds a prescribed air quality standard;*	• controlled facility	• An owner or an operator	• Application to be substantiated by compliance plan • An emission compliance plan to provide road map to achieve the stipulated emission limits.
<u>Measurement of emissions and occupational exposure levels</u> Any person, owner or operator of a facility listed under the **Fourth Schedule** shall ensure that ***measurement of emissions and occupational exposure levels*** are carried out in accordance with the methods of test set	**<u>Fourth Schedule</u>** Guideline on air pollution monitoring parameters from stationary sources (facilities which may be relevant for petroleum sector):	• Any person, • An owner or • An operator of a facility	**<u>Eleventh Schedule</u>** Methods of test and measurement of air pollutants • This schedule lists Kenyan's standards of methods of test

out in the **Eleventh Schedule**. [S.52 (a) AQE, 2014] The analysis of all measurements in sub-regulation (1) above shall be carried out by laboratories designated by the Authority. [S.52 (b) AQR, 2014]	• Petroleum Refineries • Waste water Treatment Plants • Boilers		and measurement of air pollutants • Please refer to the list of standards
<u>Measurement of Ambient Air Quality</u> The Authority in consultation with the relevant lead agencies may carry out ***all measurements of Ambient Air Quality levels*** in accordance with the methods of test set out in the **Eleventh Schedule**. [S 53 AQR 2014]	**<u>First Schedule</u>** Ambient air quality tolerance limits • Table 1: Ambient Air Quality Tolerance Limits	• Authority in consultation with the relevant lead agencies	**<u>Eleventh Schedule</u>** Methods of test and measurement of air pollutants • This schedule list Kenyan's standards of methods of test and measurement of air pollutants Please refer to the list of standards
<u>Visible air pollutants</u> Measurements of ***visible air pollutants*** shall be in accordance with the relevant method of measurement set out under the **Eleventh Schedule** or in accordance with any method approved by the Authority. **[S 54 AQR 2014]**	All facilities	Operator	**<u>Eleventh Schedule</u>** Methods of test and measurement of air pollutants • This schedule list Kenyan's standards of methods of test and measurement of air pollutants Please refer to the list of standards
<u>Measuring vehicular emissions</u> The procedure for measuring ***vehicular emissions*** shall be in accordance with the relevant methods of test and analysis stipulated under the **Eleventh Schedule** or any other method approved by the Authority. **[S 55 AQR 2014]**	All PSV and Commercial vehicles Vehicles that are 4 years old and above	Owners	**<u>Eleventh Schedule</u>** Methods of test and measurement of air pollutants • This schedule list Kenyan's standards of methods of test and measurement of air pollutants Please refer to the list of standards
<u>Period for storing & submission of records</u> (1) The record of the measurements carried out as required under regulation 52 shall be kept by the owner, occupier, or operator of the facility for a period of at least two years or such other period as may be prescribed by the Authority. (2) All emission test reports shall be delivered to the Authority within ninety days from the date of completion of testing. [S 56 AQR 2014] **Fifth Schedule - General Guidelines - Part XIII:- Guideline on Results of Emissions Sampling and Analysis – section 2** makes provision for		owner, occupier, or operator of the facility	

Measurements of emissions into the atmosphere from stacks, vents or other air pollutant sources, which are reported to the Authority whether voluntarily or as a requirement of these Regulations or of any condition of a licence			
Continuous monitoring system requirements. A licensee who has any of the sources of emission set out in the Third Schedule shall **install, calibrate, maintain and operate equipment for continuously monitoring and recording emission levels** in accordance with these Regulations, or equivalent emission measuring systems as may be approved by the Authority. [S. 64.(1), AQR 2014]	sources of emission set out in the Third Schedule	A licensee	In line with regulations or equivalent emission measuring systems
Maintenance and storage of air quality monitoring records. • An owner or operator of a controlled facility shall maintain air quality monitoring records for sources of air pollution in the manner prescribed by the Authority. • The monitoring records shall be in the prescribed form as set out in the Eighth Schedule. • The records referred to in paragraph (1) shall be preserved by the licensee for a period of two years or such longer period as may be prescribed by the Authority. [S. 65, AQR 2014]	Controlled facility	An owner or operator of a controlled facility	Eighth Schedule - Monitoring records
Submission of Monitoring records to Authority • An owner or operator of any facility listed in the Fourteenth Schedule shall submit the monitoring records to the Authority on a quarterly basis. [S. 68(1) AQR 2014]			
Guideline for monitoring air pollutants • The Authority in consultation with the relevant lead agencies may issue guidelines, including guidelines listed under Part XIII of the Fifth Schedule to these Regulations, on the monitoring of air pollutants. [S 70 AQR 2014]			

6.2.3 Air emission measurements as part of the air monitoring process

Air emissions measurement is part of the air quality/emission monitoring process. Environmental monitoring programs should be developed and implemented by the companies operating in petroleum sector to monitor activities that have been identified to have potentially significant impacts on the environment during normal operations and upset conditions[33].

Environmental monitoring should address the following:

[33] IFC environmental, health, and safety guidelines for offshore oil and gas development, IFC environmental, health, and safety guidelines for onshore oil and gas development

1. Environmental monitoring activities should be based on direct or indirect indicators of emissions applicable to the particular project.
2. Monitoring frequency should be sufficient to provide representative data for the parameter being monitored.
3. Monitoring should be conducted by trained individuals following monitoring and recordkeeping procedures and using properly calibrated and maintained equipment.
4. Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards, so that any necessary corrective actions can be taken.
5. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the General IFC EHS Guidelines[34].

The air quality monitoring program should consider the following elements[35]:

- **Monitoring parameters**: The monitoring parameters selected should reflect the pollutants of concern associated with project processes. For combustion processes, indicator parameters typically include the quality of inputs, such as the sulfur content of fuel.
- **Baseline calculations**: Before a project is developed, baseline air quality monitoring at and in the vicinity of the site should be undertaken to assess background levels of key pollutants, in order to differentiate between existing ambient conditions and project-related impacts.
- **Monitoring type and frequency**: Data on emissions and ambient air quality generated through the monitoring program should be representative of the emissions discharged by the project over time. Examples of time-dependent variations in the manufacturing process include batch process manufacturing and seasonal process variations. Emissions from highly variable processes may need to be sampled more frequently or through composite methods. Emissions monitoring frequency and duration may also range from continuous for some combustion process operating parameters or inputs (e.g. the quality of fuel) to less frequent, monthly, quarterly or yearly stack tests.
- **Monitoring locations**: Ambient air quality monitoring may consists of off-site or fence line monitoring either by the project sponsor, the competent government agency, or by collaboration between both. The location of ambient air quality monitoring stations should be established based on the results of scientific methods and mathematical models to estimate potential impact to the receiving airshed from an emissions source taking into consideration such aspects as the location of potentially affected communities and prevailing wind directions in accordance with international guidelines.
- **Sampling and analysis methods**: Monitoring programs should apply national or international methods for sample collection and analysis, such as those published by the Kenya Bureau of Standards; International Organization for Standardization, the European Committee for Standardization, or the U.S. Environmental Protection Agency. Sampling should be conducted by, or under, the supervision of trained individuals. Analysis should be conducted by entities permitted or certified for this purpose. Sampling and analysis Quality Assurance / Quality Control (QA/QC) plans should be applied and documented to ensure that data quality is adequate for the intended data use (e.g., method detection limits are below levels of concern). Monitoring reports should include QA/QC documentation.

6.2.4 Summary of best practices for environmental monitoring of air emissions:

Monitoring parameters selected against each of the lifecycle phases should reflect the pollutants and activities of concern associated with proposed and actual operations and should address both the monitoring of emissions as well as impacts on the receiving environment.

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[34] IFC Environmental, Health, and Safety General Guidelines, https://www.ifc.org/wps/wcm/connect/554e8d80488658e4b76af76a6515bb18/Final+-+General+EHS+Guidelines.pdf?MOD=AJPERES

[35] I IFC environmental, health, and safety guidelines for offshore oil and gas development, IFC environmental, health, and safety guidelines for onshore oil and gas development

Monitoring should be carried out with a clear overall objective, and a strategy that considers parameters including ecosystem context, location, contaminant properties, and levels of detectable change in the receiving environment.

This section is based on best practices summarized in the European Union Hydrocarbons BREF (Best Available Techniques (BAT) Reference document)[36].

Monitoring may include, for example:

- Collection of information and data for assessing baseline conditions (e.g. at the approval stage of a development) and for undertaking environmental assessments (e.g. during design and operations).
- Measuring and/or estimating environmental parameters and potential environmental impacts (e.g. during production), such as: emissions to air (e.g. CO, CO2, NOx , SOx, CH4, NMVOCs, PM, ozone, particulates, odour) by calculation and/or direct measurement – emissions from power generation, flares and process equipment (e.g. from acid gas removal unit (AGRU) incinerators, hot-oil furnaces, steam boilers, etc.); fugitive emissions (e.g. from compressor seals, valves, flanges and pumps); vented emissions (e.g. from storage and loading facilities); and other process emissions;
- Monitoring also occurs for unintended releases (e.g. leak detection systems and reactive monitoring). Examples of unintended releases include a leak of gas from process equipment or a loss of containment from gas production or storage.

The best risk management approaches for environmental monitoring as they apply to air quality and emissions include the following:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for environmental monitoring.
- Ensure that environmental monitoring is addressed as part of management measures detailed in an environmental risk assessment such as an EIA.
- Develop and implement a risk-based Environmental Monitoring Programme, covering all activities and aspects that have potential environmental impacts, and includes elements as set out in the environmental risk assessment.

The following techniques are considered BAT for environmental monitoring as it applies to air quality and emissions:

Design

- Provide sampling ports on combustion equipment, where safe to do so, including gas turbines, generators, etc. for sampling of exhaust gas, and concentrations of CO, SOx , NOx . Sampling ports provide the location at which portable gas detectors are inserted to monitor emissions.
- Quantify fugitive emissions in design based on the number of components in hydrocarbon service and generic emission factors. Once in operation these should be revised, and facility specific factors used in place of the default design factors.

Operations

- Monitor flare emissions by calculation and/or direct measurement (where applicable). An alternative to direct measurement of flare gas flow is to measure or otherwise determine all contributory flows into the flare gas system. Analysis may be performed to determine flare gas composition.

[36] https://ec.europa.eu/environment/integration/energy/pdf/hydrocarbons_guidance_doc.pdf

- Monitor emissions to air by calculation and/or direct measurement, including for example H2S, BTEX, NOx, SO2, PM, VOC, CO, CO2, CH4 from:
    - Point source emissions to air from combustion emissions and gas flares.
    - Fugitive emissions.
- Monitor diesel fuel and fuel gas usage (if applicable). Report diesel and fuel gas usage and emissions to the Regulatory Authority once a facility is operational.

6.2.5 Description of air emission measurements methods

Several approaches can be taken by petroleum companies to monitor a specific parameters/emissions, including[37]:

- direct measurement methods:
    - continuous measurements
    - periodic measurements
    - campaign measurements
- indirect methods
    - surrogate parameters
    - mass balances
    - emission factors
    - other calculations

In principle, direct measurements (specific quantitative determination of the emitted compounds) are preferred, as they are more straightforward, but they are not necessarily always more accurate. In cases where direct measurements are complex, costly and/or impractical, other methods could be more appropriate.

Petroleum companies shall select and approve with NEMA air emission measurement and monitoring methods that will provide a comprehensive management of emissions from petroleum operations.

6.2.4.1 Direct methods

Regular measurements

Continuous measurements

Two types of continuous measurement techniques are generally considered as appropriate to be applied:

- *Fixed in situ (or in-line) continuous reading instruments*. These instruments do not need to withdraw any sample to analyse it and are usually approved for specific applications. There are two possible designs: The measuring cell is either placed in the duct, pipe or stream itself or the transmitter and the receiver are placed outside the stack opposite each other. Regular maintenance and calibration of these instruments is essential.

- *Fixed on-line (or extractive) continuous reading instruments*. These instruments continuously extract samples from the stream along a sampling line and transport them to an on-line measurement station, where the samples are analysed continuously. The measurement station may be far away from the stream and therefore care is taken so that the sample integrity is maintained along the sampling line. This type of equipment often requires pretreatment of the sample.

Periodic measurements

The following types of periodic measurement techniques are generally considered as appropriate to be applied:

[37] http://eippcb.jrc.ec.europa.eu/reference/BREF/ROM/ROM_2018_08_20.pdf

- *Portable instruments* used for a series of measurements. These instruments are carried to and set up at the measurement site. Normally a probe is introduced at an appropriate measurement port to measure in situ or to sample the stream and analyse it on-line. These instruments are appropriate for checking emission concentrations and also for calibrating other monitoring equipment.
- *Laboratory analysis of samples* taken by fixed on-line samplers. These samplers withdraw the sample continuously and collect it in a container. From this container, a portion is then analysed in the laboratory, giving an average concentration over the total volume accumulated in the container. The amount of sample withdrawn can be proportional to time or to flow and has to be sufficient for the applied measurement technique.
- *Laboratory analysis of spot samples*. A spot sample is a sample taken from the sampling point at a certain time over a certain time period. The sample is then analysed in the laboratory, providing an average over the sampling period, which is representative of the time at which the sample was taken. The amount of sample taken has to be sufficient for the applied measurement technique.

Continuous versus periodic measurements

Continuous measurement techniques have an advantage over periodic measurement techniques as they provide a larger amount of data that can facilitate statistical analysis and can highlight periods of different operating conditions and should be considered for adoption by petroleum industry companies over employment of periodic measurements, where practical and in compliance with local requirements. Continuous measurement techniques, though, may also have some drawbacks, e.g. they need to be calibrated regularly with periodic standard reference methods.

For **continuous measurements**, it is obvious that averaging is necessary to summarise the results. Depending on the time period and the number of validated values, the result of the measurement can for example be a half-hourly, hourly, daily, monthly or yearly average. In some cases, a validation is carried out before averaging the measurement results.

The following guiding principles should be observed:

.	Averaging period for Emissions to air	Description
	Daily average	Average over a period of 24 hours of valid half-hourly or hourly averages obtained by continuous measurements (1)
	Monthly/Yearly average	Average calculated from the 10-minute, half-hourly, hourly or daily averages obtained by continuous measurements during one month/year (1)
	Average over the sampling duration	Average over at least 30 minutes obtained by periodic measurements (2)
	Daily/Monthly/Yearly average (3) as specific load	Average over a period of one day/month/year expressed as mass of emitted substances per unit of mass of products/materials generated or processed
(1) Continuous measurement means, according to EN 14181:2014, measurements with an automated measuring system (AMS) permanently installed on site for the continuous monitoring of emissions or measurement of peripheral parameters [36, CEN 2014]. (2) Periodic measurement means, according to EN 15259:2007, determination of a measurand at specified time intervals [45, CEN 2007]. (3) The averaging period of the specific load and the minimum monitoring frequency have to be defined according to the requirements of the specific industrial sector.		

For **periodic measurements**, the result of a measurement is an average over the sampling period, which can be, for example, 30 minutes for measurements of emissions to air.

Continuous measurements are carried out with an automated measuring system which is permanently installed on site for the continuous monitoring of emissions. Periodic measurement is defined as the determination of a measurement at specified time intervals.

Important characteristics of continuous and periodic measurements are summarized in the table below and should be observed:

Characteristic	Continuous measurement	Periodic measurement
Sampling period	Measurement covers all or most of the time during which substances are emitted	Snapshots of the long-term emission pattern
Speed	Almost always real-time results	Real-time results if instrumental analysers are used; delayed results if a manual method with a laboratory end-method is used
Averaging of results	Results continuously gathered and can be averaged over a given period, e.g. 30 minutes, 1 hour or 24 hours	Results over the sampling period, typically 30 minutes to several hours
Calibration and traceability	AMS require calibration against a standard reference method (SRM) (2) and adjustment with certified reference materials in the maintenance interval	Standard reference methods can be used for periodic measurements; these can be manual or automated methods
Accreditation	Quality assurance of the calibration and maintenance of AMS according to EN 14181:2014 and EN ISO/IEC 17025:2017	Quality assurance for periodic measurements according to EN ISO/IEC 17025:2017
Certification of equipment	Certification of equipment available	Certification of portable equipment available
Investment costs (1)	Higher than the costs of periodic monitoring equipment	Lower than the costs of AMS
Operating costs (1)	Normally higher than the costs of periodic measurements, in particular if it includes QAL2, QAL3, AST, etc.	Normally lower than the costs of AMS

Campaign measurements

One special type of measurements are campaign measurements, which are carried out in response to a need for, or an interest in obtaining, more comprehensive information than that generally provided by routine monitoring, which is mainly performed for compliance assessment. Campaign measurements usually involve relatively detailed and sometimes extensive and expensive measurements which are usually not justified to be carried out on a regular basis. Situations in which campaign measurements might be carried out include the following:

1. a new measurement technique is to be introduced and needs to be validated;
2. a fluctuating parameter is to be investigated in order to identify the root causes of the fluctuation or to assess opportunities to reduce the range of the fluctuations;
3. a surrogate parameter is to be defined and correlated with process parameters or other emission values;
4. the actual compounds/substances of an emission are to be determined or evaluated in addition to the regular measurement of a sum parameter;
5. the ecological impact of an emission is to be assessed by ecotoxicological analyses;
6. volatile organic compounds are to be determined for odour;
7. measurement uncertainties are to be evaluated;

8. a new process is to be started without previous knowledge of emission patterns;
9. a preliminary study is necessary to design or improve techniques for the prevention or abatement of emissions (treatment systems);
10. the total emissions (of a substance) from several sources (types and characteristics) need to be determined;
11. the relative emission contribution of a pollution source to the total emissions needs to be identified (graduation emission sources);
12. a cause-effect relationship is to be investigated.

6.2.4.2 Indirect methods

Surrogate parameters

Surrogate parameters are measurable or calculable quantities which can be closely related, directly or indirectly, to conventional direct measurements of pollutants, and which may therefore be monitored and used instead of the direct pollutant values for some practical purposes. The use of surrogate parameters either individually or in combination, or also in combination with direct measurements, may provide a sufficiently reliable picture of the nature and quantity of the emission. The surrogate parameter is normally an easily and reliably measured or calculated parameter that may indicate various aspects of the process, such as throughput, energy consumption, temperatures, volumes of residue (water, air, solid waste) or emission concentrations (e.g. total volatile organic carbon (TVOC) as a surrogate parameter for organic solvents).

The surrogate parameter may provide an indication of whether another parameter is within a desired range provided that the surrogate parameter is maintained within a certain range. In specific cases, it may be possible to achieve more reliable results if the surrogate parameter is combined with direct measurements. Whenever a surrogate parameter is proposed to determine the value of another parameter of interest, the relationship between the surrogate parameter and the parameter of interest needs to be clearly identified, demonstrated and documented (e.g. via campaign measurements). In addition, traceability of the parameter's evaluation on the basis of the surrogate parameter is needed.

A surrogate parameter is only likely to be useful for monitoring purposes if:

1. it is closely and consistently related to the pollutant to be measured;
2. it is more economical or easier to monitor than it is to carry out direct measurements or if it can provide more frequent information;
3. it is capable of being related to specified limits;
4. the operating conditions when surrogate parameters are monitored match the conditions when direct measurements are required;
5. its use is generally supported and approved by sufficient data; this implies that any extra uncertainty due to the surrogate parameter is insignificant for regulatory decisions;
6. it is properly described, including regular evaluation and follow-up.

Mass balances

Mass balances can be used for an estimation of the emissions to the environment from an installation, process or piece of equipment. The procedure normally accounts for inputs, accumulations, outputs and the generation or destruction of the substance of interest, and the difference is accounted for as a release to the environment. The use of mass balances has the greatest potential when:

- emissions are of the same order of magnitude as inputs or outputs;
- the amounts of the substance (input, output, transfer, accumulation) can be readily quantified over a defined period of time.

Emission factors

Emission factors are numbers that can be multiplied by an activity rate (e.g. the production output, water consumption, number of animals), in order to estimate the emissions from the installation. They are applied under the assumption that all (agro-)industrial units of the same product line have similar emission patterns. These factors are widely used for determining emissions at small installations.

Emission factors are generally derived through the testing of a population of similar process equipment (e.g. boilers using a particular fuel type) or process steps for a specific (agro-)industrial sector. This information can be used to relate the quantity of material emitted to some general measure of the scale of activity (e.g. for boilers, emission factors are generally based on the quantity of fuel consumed or the heat output of the boiler). In the absence of other information, default emission factors (e.g. literature values) can be used to provide an estimate of the emissions (e.g. there are different emission factors available for ammonia or odour units emitted per animal place for different types of animals).

Other calculations

Theoretical and complex equations, or models, can be used for estimating emissions from industrial processes. Estimations can be made by calculations based on the physico-chemical properties of the substance (e.g. vapour pressure) and on physico-chemical relationships (e.g. ideal gas law). The use of models and related calculations requires that all necessary corresponding input data are available. Usually models provide a reasonable estimate:

1. if they are based on valid assumptions, as demonstrated by previous validations;
2. if their inherent uncertainty is sufficiently low;
3. if suitable sensitivity analyses results are presented alongside them;
4. if the scope of the model corresponds to the case studied;
5. if input data are reliable and specific to the conditions of the installation.

When evaluating and comparing monitoring data, it is important to have information on how the measurement results were processed. Information on the averaging of measurement results and the measurement uncertainty related to these results is of fundamental importance.

6.2.4.3 Procedural measures to be observed for emission measurement:

JRC Reference Report on Monitoring of Emissions to Air and Water from IED Installations[38] can be consulted for the following requirements related to both continuous and periodic monitoring and emission measurement practices.

This JRC Reference Report on Monitoring (ROM) summarises information on the monitoring of emissions to air and water from IED installations, thereby providing practical guidance for the application of the Best Available Techniques (BAT) conclusions on monitoring in order to help competent authorities to define monitoring requirements in the permits of IED installations. This reference report is listed in the Hydrocarbon BREF for monitoring emissions to air by calculation and/or direct measurement.

6.2.4.3.1 Continuous measurement of air emissions

6.2.4.3.1 (a) Indicative general standards relevant for continuous measurements of air emissions

The table below provides for indicative list of general standards relevant for continuous measurements of air emissions to be observed by petroleum companies.

Standard	Title
Continuous Monitoring	
EN ISO 9169:2006	Air quality - Definition and determination of performance characteristics of an automatic measuring system (ISO 9169:2006)

[38] JRC Reference Report on Monitoring of Emissions to Air and Water from IED Installations https://eippcb.jrc.ec.europa.eu/sites/default/files/2019-12/ROM_2018_08_20.pdf

EN 14181:2014	Stationary source emissions - Quality assurance of automated measuring systems
EN 15259:2007	Air quality - Measurement of stationary source emissions - Requirements for measurement sections and sites and for the measurement objective, plan and report
EN 15267-1:2009	Air quality - Certification of automated measuring systems - Part 1: General principles
EN 15267-2:2009	Air quality - Certification of automated measuring systems - Part 2: Initial assessment of the AMS manufacturer's quality management system and post certification surveillance for the manufacturing process
EN 15267-3:2007	Air quality - Certification of automated measuring systems - Part 3: Performance criteria and test procedures for automated measuring systems for monitoring emissions from stationary sources

At the time of drafting this guideline it is understood that these standards have not been officially adopted in Kenya.

6.2.4.3.1 (b) Quality assurance

Automated Monitoring System (AMS) should be certified, where required in accordance with relevant Kenyan or international standards prior to putting it into operation, where such certification is required by Kenya's law or international best practices.

AMS should be tested by accredited laboratory after installation. Testing is required to be repeated periodically at least every five years.

6.2.4.3.1 (c) Measurement/Sampling site, section, plane and point for AMS

Working platform of an AMS should be is easily accessible, clean, well ventilated, well-lit and in accordance with applicable international or Kenyan standards. Suitable protection for the personnel and the equipment is required if the working platform is exposed to the weather. The working platform shall have a sufficient load-bearing capacity and shall provide sufficient working space (i.e. area and height) to manipulate the AMS.

Continuous measurements are usually restricted to measurement/sampling at a single point or along a single line of sight. The measurement/sampling points should be located in a position that allows representative measurement/sampling of the emission.

6.2.4.3.1 (d) Analysis for extractive and non-extractive ASM and their methods

Two different kinds of AMS are available for the continuous measurement of emissions: extractive and non-extractive AMS. For most of the parameters 2 both types of AMS are available.

In the case of an extractive AMS, a gas sample is taken from the main gas stream by a sampling system and sent to the measurement device, which is physically separated from the sampling point. This requires suitable sampling equipment, but allows, if necessary, a special treatment of the sampled gas stream. The sampling path should be kept as short as possible, to enable short response times and to avoid possible sample losses. All gas sampling lines and components of the measurement device are made of suitable material; on the one hand to prevent corrosion and on the other hand to avoid reactions between these materials and the measured component. Probes, filters and sample gas tubing, up to the sample gas cooler (if used for condensate separation), are heated to above the dew point temperature.

In the **non-extractive AMS**, the measurement device is installed across the stack in the gas stream or in a part of it (*in situ* measurement). Therefore, no extractive sampling is necessary. In principle, a non-extractive AMS is more prone to interferences from other waste gas components than an extractive AMS, as there is usually little or no sample pretreatment. For example, a high humidity in the waste gas stream may require the use of an extractive AMS. Because the measurements are carried out in wet conditions and at the operating temperature in the stack, this needs to be considered in the data processing.

6.2.4.3.1 (e) Methods of certified AMS

Indicative list of methods of certified AMS for the most common air pollutants are summarised in the table below. Companies should observe this list or approve alternative methods with relevant state bodies of Kenya.

Pollutant	Monitoring methods
Ammonia (NH_3)	FTIR, NDIR with GFC, TDL
Carbon monoxide (CO)	FTIR, NDIR
Dust	Light attenuation or scattering, triboelectric effect (i.e. the probe electrification induced by dust particles)
Hydrogen chloride (HCl)	FTIR, NDIR with GFC, TDL
Hydrogen fluoride (HF)	FTIR, TDL
Methane (CH_4)	FID, FTIR, NDIR
Mercury (Hg)	AAS, DOAS
Metals and their compounds	—
Nitrogen oxides (NOX)	Chemiluminescence, FTIR, NDIR, NDUV, DOAS
Polycyclic aromatic hydrocarbons (PAHs)	—
PCDDs/PCDFs and dioxin-like PCBs	—
Sulphur dioxide (SO_2)	FTIR, NDIR, NDUV, DOAS
Sulphur oxides (SOX)	—
Total volatile organic carbon (TVOC)	FID

NB:
AAS = atomic absorption spectrometry;
DOAS = differential optical absorption spectroscopy;
FID = flame ionisation detection;
FTIR = Fourier transform infrared spectrometry;
GFC = gas filter correlation;
NDIR = non-dispersive infrared spectrometry;
NDUV = non-dispersive UV spectrometry;
PID = photo ionisation detector;
TDL = tunable diode laser absorption spectrometry.
-

Continuous mercury measurements

Continuous measurements of total gaseous mercury are based on extractive gas sampling, filtration, conversion, possibly amalgamation, and measurement (e.g. with atomic absorption spectrometry (AAS) or atomic fluorescence spectrometry (AFS)). Sample gas conditioning plays a special role, as AAS and AFS only detect metallic mercury. Other volatile mercury compounds, mainly mercury chlorides (Hg_2Cl_2/$HgCl_2$), are thus reduced to metallic mercury prior to analysis. This is either achieved by wet chemical reduction (e.g. with tin chloride solution) or by dry reduction with converters at low (~ 250 °C) or high (~ 700 °C) temperatures. Any particle-bound mercury is not included in the result

6.2.4.3.1 (f) Reference/Standard conditions

In order to compare emission levels to air, it is generally necessary to convert them to standard conditions. In most cases, this involves the correction for the temperature, the pressure and the water vapour content.

The measured emission concentrations are converted to a temperature of 273.15 K and a pressure of 101.3 kPa after the deduction of the water vapour content (thereby referring to dry gas). In many cases, the standard conditions also include a reference oxygen level (e.g. for flue-gases from combustion or incineration processes). The correction for the oxygen content is usually carried out in the case of combustion and incineration processes in order to account for the dilution of the waste gas that is caused by the combustion air.

When calculating emission rates, for example in kg/h, different temperature, pressure, oxygen and water vapour levels do not affect the calculated result, provided that the mass concentration (e.g. in mg/m3) and the volume flow rate (e.g. in m3/h) are expressed at the same conditions. Therefore, no conversion to standard conditions is needed for the calculation of emission rates.

6.2.4.3.1 (g) Data treatment

The response time as the time interval between the instant of a sudden change in the value of the input quantity to an AMS and the time from which the value of the output quantity is reliably maintained above 90 % of the correct value of the input quantity. The response time ranges from about 5 seconds up to a maximum of 200 seconds for particulate matter and gaseous compounds, except for NH3, HCl and HF for which the response time may be as high as 400 seconds.

Averaging periods usually vary from 10 to 60 minutes, depending on the permit requirements. Most commonly, half-hourly or hourly averages are calculated. In the same way, data from peripheral measurements (e.g. oxygen, water vapour) are averaged and the half-hourly or hourly averages of the pollutant concentrations are converted to the corresponding standard conditions.

6.2.4.3.1 (h) Reporting requirements

It is good practice to report measurement results on a daily, monthly and/or yearly basis, depending on the specific requirements set by the permit. The daily and/or monthly reports should contain sufficient data to serve as background information to the yearly report. In particular, to allow a full assessment of the daily/monthly/yearly emissions, it is advisable that the reports contain at least the following data:

1. data related to the daily operating conditions and hours indicating normal and other than normal operating conditions;
2. half-hourly/hourly averages, standardised half-hourly/hourly averages and validated half-hourly/hourly averages of the specific day (or for any other required averaging period);
3. frequency distribution of the half-hourly/hourly, daily and/or monthly averages for the calendar year;
4. declaration of measurement results related to special (operating) conditions, with an indication of the event;
5. indication of the measurement results outside the valid calibration range and data related to the validity of the calibration function;
6. date and duration of power outages of the AMS;
7. date and duration of times for testing and maintenance of the AMS.

The measurement report should describe, in a transparent and traceable way, where and how the measurements were carried out and should also provide sufficient detail to enable the results to be traced back through the calculations to the collected raw data and operating conditions.

An emission measurement report includes at least the following information:

1. general information, such as the operator's name, the address of the installation, the name and the address of the testing laboratory;
2. definition of the project by specification of the measurement objective(s);
3. description of the installation and materials handled;
4. identification of the measurement site and section;
5. identification of the measurement methods and apparatus according to individual standards for the measured pollutants and reference quantities;
6. operating conditions of the production process during the measurement, including the waste gas treatment units;

7. identification of deviations from the measurement plan;
8. reference to how to access and use the original data for verification purposes;
9. measurement results and other relevant data necessary for the interpretation of the results, including the sampling date (hour, day, month and year) and measurement uncertainties;
10. calculation procedures, such as the conversion of data to specific standard conditions;
11. presentation of the results.

6.2.4.3.2 Periodic measurement of air emissions

6.2.4.3.2 (a) Indicative general standards relevant for periodic measurements of air emissions

The table below provides for an indicative list of general standards relevant for periodic measurements of air emissions to be observed by petroleum companies.

Standard	Title
Periodic Monitoring	
EN 14793:2017	Stationary source emissions - Demonstration of equivalence of an alternative method with a reference method
EN 15259:2007	Air quality - Measurement of stationary source emissions - Requirements for measurement sections and sites and for the measurement objective, plan and report
EN 15267-4:2017	Air quality - Certification of automated measuring systems - Part 4: Performance criteria and test procedures for automated measuring systems for periodic measurements of emissions from stationary sources
CEN/TS 15674:2007	Air quality - Measurement of stationary source emissions - Guidelines for the elaboration of standardised methods

At the time of drafting this guideline it is understood that these standards have not been officially adopted in Kenya.

6.2.4.3.2 (b) Quality assurance

Certification of equipment is only available for portable automated measuring systems (P-AMS). An indicative standard EN 15267-4:2017 applies to P-AMS used for periodic measurements of stationary source emissions. P-AMS are based on measurement techniques specified by a standard reference method (SRM) or an alternative method (AM). The performance tests for P-AMS are carried out similarly to those for stationary AMS according to EN 15267-3:2007.

The relevant standard for quality assurance in operation is EN ISO/IEC 17025:2017.

6.2.4.3.2 (c) Measurement objective and measurement plan

For periodic measurements clear objectives and measurement plan shall be established.

The measurement objective should specify at least the following:

1. the purpose of the measurement;
2. the dates and times of the measurements;
3. the operating conditions under which the measurements are performed (normal operating conditions (NOC) and/or other than normal operating conditions (OTNOC), if known in advance);
4. the measurement site;
5. the measurands (i.e. pollutants and reference quantities) and the expected values;
6. the competence of the testing laboratory

The measurement plan specifies a number of issues, some of which also form part of the measurement objective:

1. the dates and times of the measurements;
2. the operating conditions under which the measurements are performed;
3. the measurement sites and sections;

4. the measurement points;
5. the number of individual measurements;
6. the timing and duration of the individual measurements;
7. the measurands (i.e. pollutants and reference quantities);
8. the measurement methods;
9. the technical supervisor, necessary personnel and auxiliary help for carrying out the measurements;
10. the reporting .

6.2.4.3.2 (d) Operating conditions

For compliance assessment, measurements should be carried out at the highest emission state of the operating conditions under investigation. The highest emission state is characterised by the highest emission mass flow which does not necessarily correspond to the maximum emission concentration of a pollutant. Depending on the permit conditions, the measurement objective can refer to concentrations or to mass flows or to both. The highest emission state corresponds to the maximum (permitted) output. However, the type and composition of the feed materials may also influence the expected emissions. The individual emission behaviour of pollutants can proceed in opposite directions depending on the conditions (e.g. CO and NOX in combustion processes)

To identify the conditions associated with the highest emission state the following shall be considered:

- specialist discussions with the operator of the facility and, if necessary, with the competent authorities;
- site visits to the plant and the measurement sites;
- knowledge of the plant type and the associated emission behaviour based on measurements which have already been carried out at the plant in question or at comparable plants;
- literature knowledge (e.g. emission factors).

In some cases, technical constraints may not allow a plant to operate at the highest emission state (e.g. due to constraints imposed by the grid operator on combined cycle combustion plants).

6.2.4.3.2 (e) Measurement/Sampling site, section and plane

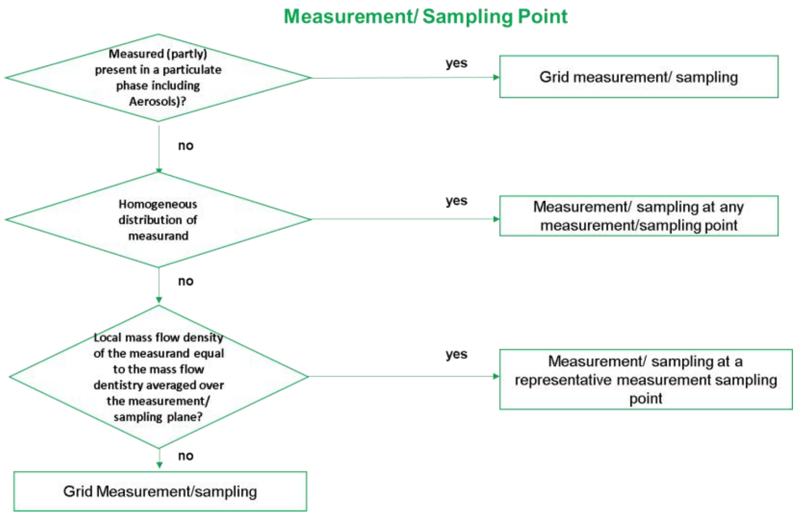
Measurement sites and sections should be designed to enable representative sampling of the waste gas and to measure the distribution of the pollutants and the reference quantities. The measurement site should allow easy access to the sampling points for typical sampling equipment, e.g. via a platform that enables personnel performing the measurement to work safely and efficiently.

Flow conditions are required in the measurement plane, i.e. an ordered and stable flow profile without vortexing and backflow, so that the waste gas velocity and the mass concentration of the measurand can be determined representatively. The measurement plane shall be situated in a section of the waste gas duct where homogeneous flow conditions and concentrations can be expected. The requirement for homogeneous flow conditions is generally fulfilled if the measurement plane is:

- as far downstream and upstream as possible from any disturbance that could produce a change in the flow direction (e.g. disturbances can be caused by bends, fans or partially closed dampers);
- in a section of the duct with at least five hydraulic diameters of straight duct upstream of the sampling plan and two hydraulic diameters downstream, and, in addition, five hydraulic diameters from the top of a stack (hydraulic diameter: ratio of four times the area and the perimeter of the measurement plane) and
- in a section of the duct with a constant shape and cross-sectional area.

6.2.4.3.2 (f) Measurement/Sampling point

The sampling strategy consists of a decision tree in order to decide on (a) representative measurement/sampling point(s)



6.2.4.3.2 (g) Number of individual measurements

The number of consecutive individual measurements in one measurement series should be specified in accordance with the measurement objective and in relation to the stability of the emission. When measuring a stable emission, best practice is to take a minimum of three samples consecutively in one measurement series. In the case of unstable emissions, the number of samples can be increased to meet the measurement objective. Depending on the permit conditions and the related averaging, it might be sufficient to carry out three measurements with a longer sampling duration (e.g. two to three hours), to measure a representative average of the unstable emission.

The minimum number of individual measurements in one measurement series is usually specified in the relevant legislation or in the permit.

6.2.4.3.2 (h) Timing and duration of individual measurements

The timing and duration of the emission measurement should be specified in the measurement plan in accordance with the measurement objective. The most common sampling duration is 30 minutes, but 60 minutes is applied as well, but this also depends on the pollutant and the emission pattern of the process.

The sampling duration depends on the mass of pollutant needed for the subsequent measurement. For this reason, some EN standards specify that the sampling duration is dependent on the expected concentration of the pollutant in the waste gas and on the measurement range of the analytical method used by the laboratory including the limit of detection. It is therefore crucial that the performance of the analytical method is considered when deciding on a suitable sampling duration. This might lead to longer sampling durations than commonly applied.

6.2.4.3.2 (i) Measurement frequency

In general, the measurement plan should refer to one or a set of measurement series, each consisting of at least three consecutive measurements at a certain date and time.

Additionally, it is also advisable to define the time intervals at which periodic measurements should be performed (measurement frequency). In practice, the following frequencies related to measurement series of at least three consecutive measurements are generally applied, taking into account also cost aspects and potential impacts for the environment:

6.2.4.3.2 (j) Analysis

For periodic measurements, the waste gas sample is extracted from the emission source and the pollutant is either analysed on-line by portable monitoring devices or fixed in an absorption liquid, on a filter or on an adsorbent. Afterwards, this liquid or solid sample is analysed in the laboratory. Therefore, the collection, storage and transport of the samples are critical for achieving a reliable measurement result.

6.2.4.3.2 (k) Reference/Standard conditions

General information on reference/standard conditions is provided in Section 6.2.4.3.1 (f).

The periodic measurement of a pollutant requires the simultaneous measurement of reference quantities.

6.2.4.3.2 (l) Data treatment

The measurement results are converted to the corresponding standard conditions (Sections 6.2.4.3.1 (f), 6.2.4.3.1 (k)).

6.2.4.3.2 (m) Reporting

The measurement report should describe, in a transparent and traceable way, where and how the measurements were carried out and should also provide sufficient detail to enable the results to be traced back through the calculations to the collected raw data and operating conditions.

An emission measurement report includes at least the following information:

1. general information, such as the operator's name, the address of the installation, the name and the address of the testing laboratory;
2. definition of the project by specification of the measurement objective(s);
3. description of the installation and materials handled;
4. identification of the measurement site and section;
5. identification of the measurement methods and apparatus according to individual standards for the measured pollutants and reference quantities;
6. operating conditions of the production process during the measurement, including the waste gas treatment units;
7. identification of deviations from the measurement plan;
8. reference to how to access and use the original data for verification purposes;
9. measurement results and other relevant data necessary for the interpretation of the results, including the sampling date (hour, day, month and year) and measurement uncertainties;
10. calculation procedures, such as the conversion of data to specific standard conditions;
11. presentation of the results.
12. any deviation from standards and measurement plan should be justified and documented in the measurement report.

In addition, every testing laboratory uses dedicated measurement or work files with much more detailed information for internal documentation. These files should allow, among others, the storage and handling of every sample to be traced, from the measurement point to the analysis of the sample, including the data treatment, and the documentation of the results.

6.2.4.3.3 Predictive Emission Monitoring Systems (PEMS)

Predictive Emission Monitoring Systems (PEMS) are systems used to determine the emission concentrations of a pollutant based on their relationship with a number of characteristic continuously monitored process parameters (e.g. fuel gas consumption, air/fuel ratio) and fuel or feed quality data (e.g. the sulphur content) of an emission source.

PEMS combine up to 25 parameters to calculate the corresponding emission concentrations of the pollutant. The calibration of these systems with direct measurements is complex, because it has to be carried out and validated under a broad range of operating conditions, but the advantage is that the resulting emission concentrations can be determined continuously without an AMS. Therefore, PEMS need to be proven to be applicable for a certain process.

6.2.4.3.4 Monitoring of fugitive emissions

Fugitive emissions - diffuse emissions from point sources. Fugitive emissions are a subset of diffuse emissions and typically originate from leaking equipment.

6.2.4.3.4 (a) Indicative general standards relevant for the monitoring of diffuse and fugitive emissions

The table below provides for indicative list of general standards relevant for monitoring of fugitive emissions to air and should be considered by petroleum company.

Standard	Title
EN 15445:2008	Fugitive and diffuse emissions of common concern to industry sectors - Qualification of fugitive dust sources by reverse dispersion modelling
EN 15446:2008	Fugitive and diffuse emissions of common concern to industry sectors - Measurement of fugitive emission of vapours generating from equipment and piping leaks
EN 16253:2013	Air quality - Atmospheric measurements near ground with active Differential Optical Absorption Spectroscopy (DOAS) - Ambient air and diffuse

EN 15445:2008 specifies a reverse dispersion modelling method to qualify the diffuse dust emission rates of industrial installations or sites. The method relies on calculations using a dispersion model and the definition of an experimental set-up for sampling. It takes into account field data such as the number, height and width of diffuse dust emission sources, the results of ambient air dust measurements, sampling distances between emission sources and sampling sites, and meteorological information. The standard does not allow quantification of the dust emission rates in absolute figures, but it is a tool to identify relevant emission sources and to implement prevention and reduction techniques. EN 15445:2008 states that it should not be used for compliance assessment or for the comparison of different installations belonging to the same industrial sector.

EN 15446:2008 applies to the measurement of fugitive emissions of volatile organic compounds (VOCs) from process equipment. VOCs are defined as all products of which at least 20 wt-% show a vapour pressure higher than 0.3 kPa at 20 °C. The method, often referred to as the 'sniffing method', uses portable instruments to detect VOC leaks from individual sources. Any detector type is allowed (e.g. based on catalytic oxidation, infrared absorption, flame ionisation or photo ionisation), provided it meets the specifications and performance criteria of the standard. In addition, Sniffing is often used in leak detection and repair (LDAR) programmes.

EN 16253:2013 describes the use of active Differential Optical Absorption Spectroscopy (DOAS) with a continuous radiation source for the determination of gaseous compounds (e.g. NO2, SO2, O3, Hg, benzene, toluene, xylene and other VOCs) in ambient air or in diffuse emissions. DOAS systems support direct multi-constituent measurements. They rely on the absorption of near ultraviolet, visible and/or near infrared light by gaseous compounds along an open monitoring path between a radiation source and a spectrometer. The measurement is conducted at wavelengths typically ranging from 250 nm to 2 500 nm and with a high spectral resolution of 0.1–1 nm. As the technique uses differential absorption instead of absolute absorption, the results are not affected by absorption and scattering due to particles or droplets. DOAS might be used as an alternative measuring technique, on which emission estimates can be based in those cases when direct measurements cannot be used adequately for the monitoring of diffuse emissions, such as emissions from area sources, and from leaks in production areas or pipeline systems.

6.2.4.3.4 (b) Other methods

Direct measurements are based on the measurement of a volume flow and a concentration in defined representative parts of an emission source area, for example under a hood, in a wind tunnel or at hall openings (windows, gates, ridge turrets)

Sniffing is described in EN 15446:2008 see above

Optical gas imaging (OGI) uses small lightweight handheld IR cameras which enable the visualisation of gas leaks in real time, so that they appear as 'smoke' on a video recorder, together with the normal image of the equipment concerned. This technique is primarily used to easily and rapidly locate significant VOC leaks, e.g. from process equipment, storage tank fittings, pipeline flanges or vents. Active OGI systems are based on the backscattering of an IR laser beam by the equipment and its surroundings, while passive OGI systems are based on the natural IR radiation emitted from the equipment and its surroundings.

An advantage of OGI is the possibility to detect leaks under insulation and to screen from a distance, so that VOC emissions from equipment not accessible for sniffing can be located. However, the sensitivity of OGI systems was reported to be lower than that of traditional sniffing equipment. OGI works particularly well with alkanes, but less so with aromatic compounds. OGI is often used in leak detection and repair (LDAR) programmes. Recent research suggests that OGI might also be used to quantify hydrocarbon emission rates under certain conditions.

6.3 Operating procedures for gas flaring and venting in line with international best practices

6.3.1 Introduction and general overview

Flaring and venting are associated with a wide range of energy development activities and operations associated with[39]:

1. Oil and gas well drilling, completion and testing;
2. Oil production (solution gas);
3. Gas production;
4. Planned non-routine depressurization of processing equipment and gas pipelines for maintenance;
5. Un-planned non-routine depressurization of process equipment and gas pipelines due to process upsets or emergency and;
6. Waste management facilities.

Associated gas brought to the surface with crude oil during oil production is sometimes disposed by venting or flaring. This practice is recognized to be a waste of valuable resources as well as a significant source of GHG emissions and emissions comprising of particulate matter (smoke), sulphur and nitrogen oxides, benz[a]pyrene and dioxin and unburned fuel components such as toluene, benzene and xylene[40]. But flaring and venting are important safety measures on oil and gas facilities, helping to ensure that gas and other hydrocarbons are safely disposed of in the event of an emergency, a power or equipment failure, or other facility upset condition. Risk assessment processes (e.g., hazard and operability study (HAZOP), hazard identification study (HAZID), etc.) to estimate the implications of situations of this type should be used in such facilities.

Under strategic environmental and social assessment of the petroleum sector in Kenya, it was recommend the flaring of natural gas should be generally prohibited except in prescribed circumstances—when approved by the Government of Kenya or when necessary for testing of facilities or for safety or emergency reasons (an approach used in a range of countries including Ghana and

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[39] AER directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting https://www.aer.ca/documents/directives/Directive060_2020.pdf

[40] IFC offshore oil and gas EHS guideline, https://www.ifc.org/wps/wcm/connect/f3a7f38048cb251ea609b76bcf395ce1/FINAL_Jun+2015_Offshore+Oil+and+Gas_EHS+Guideline.pdf?MOD=AJPERES

Mozambique). It was also recommended that development plans shall be required to account for associated gas utilization[41].

It is recognized that at present there is no coherent legal framework and associated guidelines that establish specific requirements applicable to flaring and venting in Kenya for petroleum sector.[42] However, the Petroleum Act makes some provisions for flaring and venting, which once adopted will be applicable to upstream petroleum sector. The summary of the Act requirements is provided below:

No	Provision
Petroleum Act of Kenya (Art. 89)	
89.(1)	A contractor shall not vent or flare natural gas in the course of the conduct of upstream petroleum operations except with the prior authorization of the Authority in consultation with the National Government agency responsible for environment and safety and any other National Government entity.
89 (2)	A contractor under sub-section (1) shall carry out the venting or flaring in accordance with the terms and conditions of the consent, existing laws and best petroleum sector practices.
89 (3)	Notwithstanding sub-section (l); the prior consent of the Authority shall not be required in the case of an emergency and where such venting or flaring is necessary to avert a disaster.
89 (4)	Where a contractor vents or flares under this section, such contractor shall — (a) ensure that the gas venting or flaring is kept at the lowest possible level; (b) inform the Authority of the carrying out of such venting or flaring and the circumstances requiring such action; and (c) submit to the Authority such information, as the Authority may require with respect to such venting or flaring.
89 (5)	Any application to the Authority in respect of proposed flaring of oil or natural gas shall include an evaluation of reasonable alternatives to flaring that have been considered along with information on the amount and quality of oil or natural gas involved and the duration of the requested flaring.
89 (6)	In considering the application under subsection (1) and (5), the Authority shall be satisfied that flaring is. necessary to safeguard the health and safety, of persons in the contract area or to prevent damage to the property of any person.
89 (7)	A contractor who contravenes, fails or neglects to comply with a requirement of this section commits an offence and shall on conviction be liable to a fine of not less than one hundred million shillings or a jail term of not less than ten years or both.

Therefore, the aim of this section is to provide for a general guiding framework as to how flaring and venting should be carried in petroleum sector of Kenya with the main focus on upstream petroleum operations.

NEMA has adopted CASA's framework for managing routine solution gas flares and has extended its application of the hierarchy to include flaring and venting of gas in general[43]. Therefore, petroleum companies should evaluate the following three options:

- Can flaring and venting be eliminated
- Can flaring and venting be reduced
- Will flaring and venting meet performance standards

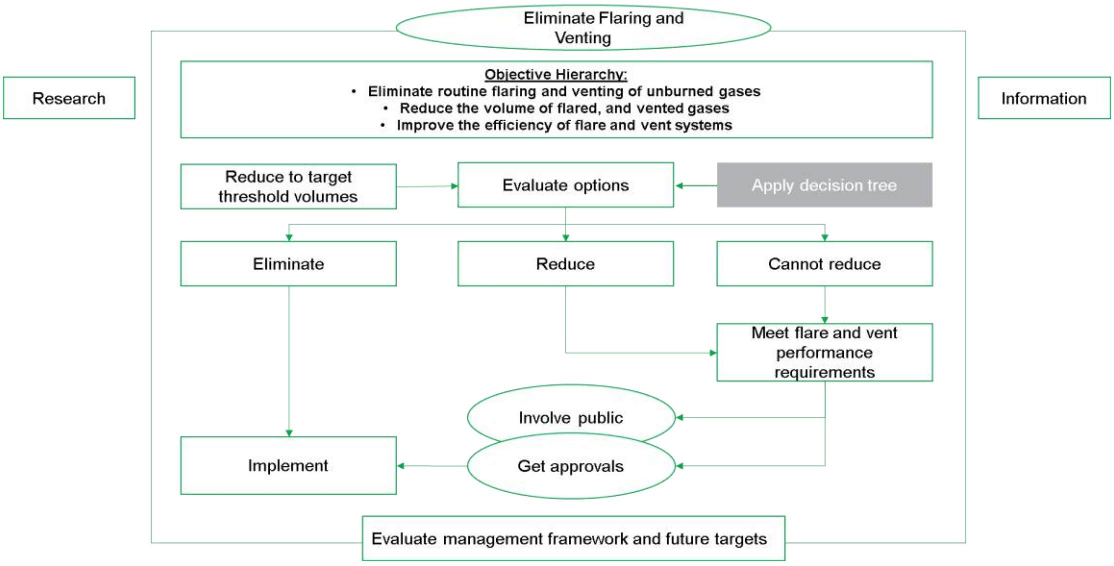
Solution gas flaring/venting management framework (adapted from CASA)[44]

[41] Strategic environmental and social assessment of the petroleum sector in Kenya http://documents.worldbank.org/curated/en/186991495657679496/pdf/SFG2851-V2-EA-P145234-Box402910B-PUBLIC-Disclosed-5-24-2017.pdf

[42] Ibid

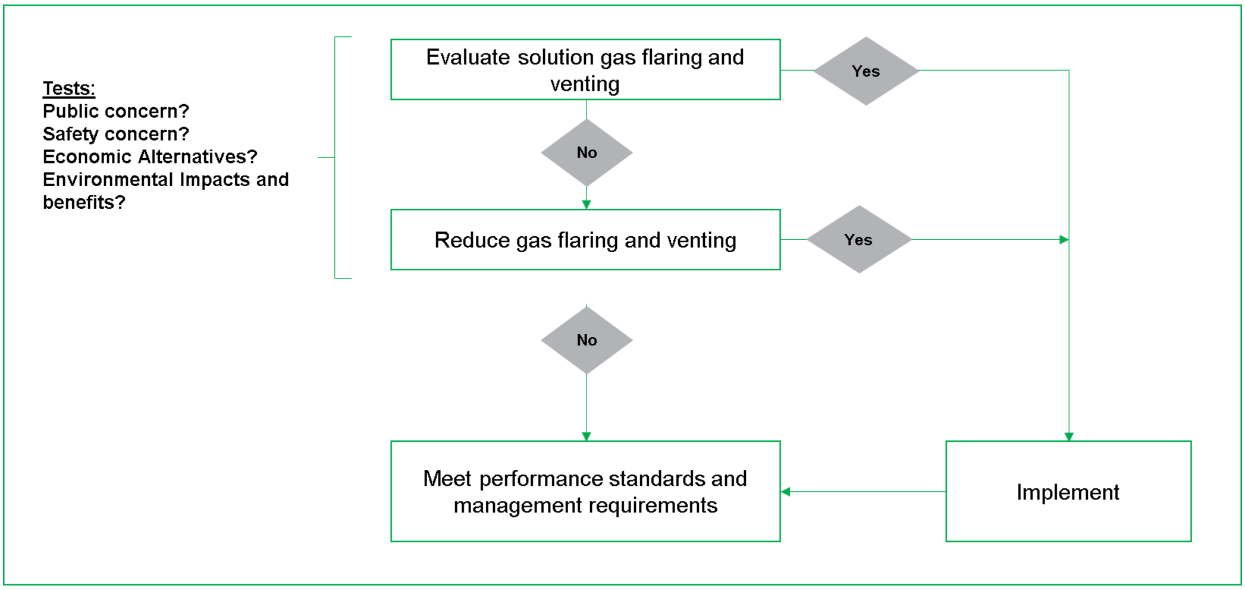
[43] Clean Air Strategic Alliance http://www.casahome.org

[44] AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting for an appropriate decision tree https://www.aer.ca/documents/directives/Directive060_2020.pdf



NEMA adopts the solution gas flaring/venting management framework and endorses the solution gas flaring and venting decision tree process as recommended by CASA.

Petroleum companies should apply this decision tree to combined flaring and venting of more than 900 m3 /day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.



For the indicative list of performance standards and requirements refer Annex F of the guideline.

6.3.2 Continuous venting and flaring[45]

Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard[46] (part of the Global Gas Flaring Reduction Public-Private Partnership) should be adopted when considering venting and flaring options for upstream petroleum operation of Kenya. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

[45] As per requirements of IFC EHS guideline for onshore and offshore oil and gas

[46] A voluntary standard for global gas flaring and venting reduction http://documents.worldbank.org/curated/en/342761468780614074/pdf/295550GGF0a0pu1ship10no10401public1.pdf

Continuous venting of associated gas is not good practice and should be avoided where practical. The associated gas stream should be routed to an efficient flare system, although continuous flaring of gas should be avoided if alternatives are available. Before flaring is adopted, all feasible alternatives for associated gas's use should be evaluated to the maximum extent possible and integrated into production design. Alternative options may include:

- gas utilization for on-site energy needs,
- gas injection for reservoir pressure maintenance,
- enhanced oil recovery using gas lift,
- export of the gas to a neighboring facility or to market.

An assessment of alternatives should be made and adequately documented. If none of the options for the associated gas's use is feasible, measures to minimize flare volumes should be evaluated and flaring should be considered as an interim solution, with the elimination of continuous production associated gas flaring as the preferred goal.

New facilities should be designed, constructed, and operated so as to avoid routine flaring. Cost effective options to reduce flaring from existing or legacy facilities that offer sustainable social benefits (e.g., gas-to-power) should be identified and evaluated in collaboration with host country governments and other stakeholders and with a particular focus on GHG emissions.

If flaring is the only viable solution, continuous improvement of flaring through the implementation of good practices and new technologies should be demonstrated. The following pollution prevention and control measures in addition to these specified in S. 6.1 of this guideline should be considered for gas flaring:

1. Implement source gas reduction measures to the extent possible.
2. Use efficient flare tips and optimize the size and number of burning nozzles.
3. Maximize flare combustion efficiency by controlling and optimizing flare fuel, air, and stream flow rates to ensure the correct ratio of assist stream to flare stream.
4. Minimize flaring from purges and pilots—without compromising safety—through measures including installation of purge gas reduction devices, vapor recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots.
5. Minimize risk of pilot blowout by ensuring sufficient exit velocity and providing wind guards.
6. Use a reliable pilot ignition system.
7. Install high-integrity instrument pressure protection systems, where appropriate, to reduce overpressure events and avoid or reduce flaring situations.
8. Minimize liquid carryover and entrainment in the gas flare stream with a suitable liquid separation system.
9. Minimize flame lift off and/or flame lick.
10. Operate flare to control odor and visible smoke emissions (no visible black smoke).
11. Situate flare at a safe distance from accommodation units.
12. Implement burner maintenance and replacement programs to ensure continuous maximum flare efficiency.
13. Meter flare gas.

It is recommended that flare systems be designed and operated consistent with industry best practices and in accordance with appropriate engineering codes and standards, such as, for example, the American Petroleum Institute's Recommended Practices 521[47]. This recommended practice is applicable to pressure-relieving and vapor depressuring systems. The information provided is designed to aid in the selection of the system that is most appropriate for the risks and circumstances involved in various installations. This recommended practice is intended to supplement the practices set forth in API Recommended Practice 520, Part 1, for establishing a basis of design. This recommended practice

[47] Ibid

provides guidelines for examining the principal causes of overpressure; determining individual relieving rates; and selecting and designing disposal systems, including such component parts as vessels, flares, and vent stacks. Piping information pertinent to pressure-relieving systems is presented in 5.4.1, but the actual piping should be designed in accordance with ASME B31.3 or other applicable codes. Health risks may be associated with the operation of pressure-relieving equipment. The discussion of specific risks is outside the scope of this document.

6.3.3 Emergency flaring[48]

In the event of an emergency or equipment breakdown, or when facility upset conditions arise, excess gas should not be vented but rather should be sent to an efficient flare gas system. Emergency venting may be necessary under specific field conditions where a flare gas system is not available or when flaring of the gas stream is not possible, such as when there is a lack of sufficient hydrocarbon content in the gas stream to support combustion or a lack of sufficient gas pressure to allow it to enter the flare system.

Justification for excluding a gas flaring system at the upstream petroleum facilities should be fully documented before an emergency gas venting facility is considered.

To minimize flaring events as a result of equipment breakdowns and facility upsets, plant reliability should be high (>95 percent) and provisions should be made for equipment sparing and plant turn-down protocols.

Flaring volumes for new facilities should be estimated during the initial commissioning period so that appropriate flaring targets can be developed. The volumes of gas flared for all flaring events should be recorded and reported.

6.3.4. Well Testing

During well testing, flaring of produced hydrocarbons should be avoided, especially in environmentally sensitive areas. Feasible alternatives should be evaluated for the recovery of these test fluids, with the safety of handling volatile hydrocarbons considered, either for transfer to a processing facility or for alternative disposal options. An evaluation of alternatives for produced hydrocarbons should be adequately documented.

If flaring is the sole option available for the disposal of test fluids, only the minimum volume of hydrocarbons required for the test should be flowed and well-test durations should be reduced to the extent practical. An efficient test flare burner head equipped with an appropriate combustion enhancement system should be selected to minimize incomplete combustion, black smoke, and hydrocarbon fallout to the sea. Volumes of hydrocarbons flared should be recorded.

Flaring during the well testing is subject to a consent granted by NEMA in accordance with S. 6.3.5 of this guideline.

6.3.5 Flaring Consent

NEMA is the authority of Kenya responsible for issue of flaring and venting consent. Where needed it will be issuing such consent in consultation/pre-approval from other relevant agencies of Kenya.

NEMA will review all flare and vent consent requests to ensure the flare and vent volume requested is at a level that is technically and economically justified.

NEMA requires operators to execute their operations in a proper manner in accordance with methods and practice customarily used in good oilfield practice. NEMA encourages applicants to engage with the NEMA at the earliest opportunity if any events, planned or unplanned, have led to, or are expected to cause, breach of consent.

[48] Ibid

NEMA will require technical and economic justification prior to approval of any consent and its amendments due to unplanned events.

6.3.5.1 Flaring and venting consents during commissioning[49]

6.3.5.1 (a) Introduction

During the commissioning of production facilities flaring and venting consents are usually restricted in duration to between one (1) and three (3) months to assure stable operating conditions and will be for a fixed quantity of gas based on an auditable programme.

For vent consents, both the inert gas and hydrocarbon fraction obtained from the licensed area should be given, and the combined rate for both will be the basis for the consent.

For flaring, only the hydrocarbon fraction flared from the licensed area requires consent but NEMA will require the inert gas content of the flare to be provided for information.

6.3.5.1 (b) Key principles

The following principles shall be adhered to:

Commissioning Philosophy:

Gas flaring and venting during commissioning should be kept to the lowest level that is consistent with the safe and efficient commissioning of oil and gas related plant.

Installation and hook-up: All gas plant must be complete, fully leak tested and otherwise tested and commissioned as far as is practicable, and able to receive gas, before first oil. A gas flaring consent will not be issued until the NEMA is satisfied that the system is ready to receive gas as soon as stabilised flow is achieved.

Commissioning and planning: This should be based on the assumption that, within one week of first oil, gas will be being used to commission gas handling plant. If gas plant commissioning cannot begin within two weeks of first oil, or there is a significant delay in commissioning due to plant breakdown or malfunction, the NEMA together with MoPM may need to consider limiting production until gas plant commissioning can proceed.

6.3.5.1 (c) commissioning gas flaring and venting consent applications

A flare and/or vent consent must be obtained from the NEMA prior to any gas being flared or vented.

For flare and vent consents associated with commissioning of facilities, Operators must submit supporting documentation to NEMA, detailing the commissioning procedure, and the expected flare and vent volumes associated with the commissioning plan.

NEMA will review this documentation and if satisfied that the commissioning plan achieves the lowest level of flare/vent that is consistent with the safe and efficient commissioning of oil and gas related plant, then the flare and vent figures can then be used as the basis for the flare and vent consent application.

Supporting documentation should be submitted at least two to three months before expected production start-up. Depending on the complexity of the facilities to be commissioned and/or the size of the project, the requirements of the supporting documentation may differ.

Advice on the level of detail required should be sought from NEMA. As a minimum, the documentation should contain:

1. A brief overview of the field and associated main facilities.
2. A detailed description of the plant commissioning philosophy and procedure, including gas export line commissioning should this be applicable

[49] This section was drafted based on UK guiding note on Flaring and venting during commissioning https://www.ogauthority.co.uk/media/2468/flaring-and-venting-during-commissioning-1016.pdf

3. The commissioning schedule
4. A summary of the main flaring assumptions.
5. Flaring and/or venting calculations - on a daily basis and total quantities
6. Sketches and figures should be as follows: o
    a. High level field layout
    b. Process flow diagram
7. Gas compression, dehydration, gas export and fuel gas systems

6.3.5.1. (d) Commissioning flare and vent consent application process:

The commissioning consent is intended to cover the period from first oil or gas to achieving stable plant operations. It is a requirement of these consents that the operator shall provide weekly reports to the NEMA detailing the following information relating to the previous week's activity:

1. a short technical summary of the performance of the gas handling plant, highlighting any features which have affected or could affect the operation of the plant;
2. an update on commissioning activity progress and main works planned for the forthcoming period;
3. daily rates in respect of oil production, gas production, gas export, gas used for fuel and of gas flare;
4. cumulative average for production and flare; and
5. gas compression plant uptime.

6.3.5.2 Flaring and venting consents during production[50]

6.3.5.2 (a) Introduction

Following commissioning, flare and vent consents are normally issued on an annual basis. Shorter duration consents may be issued at NEMA's discretion; which will only occur if NEMA has concerns over the level of gas flaring at an installation.

For vent consents, both the inert gas and hydrocarbon fraction obtained from the licensed area should be given, and the combined rate for both will be the basis for the consent.

For flaring, only the hydrocarbon fraction flared from the licensed area requires consent but the OGA will require the inert gas content of the flare to be provided for information.

6.3.5.2 (b) Consent objectives

The objective of the flare and vent consent applications is to prepare a realistic forecast based on these guidelines. For annual consents the performance for the current year and past performance should provide a starting point for this forecast.

NEMA is committed to eliminating all unnecessary or wasteful flaring and venting of gas. Operators should seek to minimise this by implementing best practice at an early stage in the design of the development and by continuing to improve on this during the subsequent operational phase. The operator should consider carefully all operational activities in accordance with good oil field practices, taking into consideration plant uptime, efficient processing, handling, uses and transportation of gas. The application must be submitted in mass units.

6.3.5.2 (c) Approach to flare application

The following points should be noted by the Operators:

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[50] This section was drafted based on UK guiding note on Flaring and venting during production
https://www.ogauthority.co.uk/media/2467/flaring-and-venting-during-the-production-phase-1016.pdf

1. Consents will be issued on a field basis, or where several fields tie-in into common facilities, the operator may apply for a single, composite consent.
2. If a tie back of a new field to an existing facility occurs, the extant flare consent must be varied to include the new field, or a separate flare consent for the new field should be applied for.
3. One field flare consent will continue to cover a field where flaring takes place on a number of installations
4. No carrying forward of flare allowance from one year to the next will be permitted.
5. If it appears that the flare consent will be breached, NEMA (following submittal of a variation to the extant flare consent) will consider issuing a revised consent. It is the operator's responsibility to present a technical case to NEMA in a timely manner (i.e. as soon as it becomes apparent that a breach is likely) in the event that a revision is required.
6. For any application leading to a facility 'total' consent (i.e. the sum of the consents of all fields' producing to the facility) of less than 40 tonnes a day it is sufficient to complete only the minimum of information. However, operators must still exercise appropriate technical and operational diligence in estimating quantities.
7. Any application leading to a facility 'total' consent (i.e. the sum of the consents of all fields' producing to the facility) of greater than 40 tonnes a day will be subjected to detailed review by NEMA. These applications will require the Operator to provide full supporting details and to exercise a high level of technical and operational diligence in estimating quantities. This level of flare is considered to represent a potential opportunity for flare reduction and therefore Operators must submit details of medium- and long-term plans for flare reduction.
8. New fields are subject to normal short-term commissioning flare consents until stable production is achieved, when a decision will be made as to what consent duration will be issued (depending upon flare level sought)
9. There are a number of methods to quantify gas volume flared and likewise, a number of methods to convert this to a mass basis. Operators should ensure the methodology they have in place meets or exceeds the necessary levels of accuracy.
10. All units are water dry metric tonnes.
11. All fields will continue to report quantities to NEMA.

Consent issued by NEMA will specify the flaring volume that must not be exceeded over a specified period.

6.3.5.2 (d) Approach to venting application

Unignited vents - inert gases and hydrocarbons gases that may be discharged to an atmospheric vent. This should also include venting of gases from onboard crude oil storage tanks; e.g. for FPSOs during crude oil filling operations. However, this excludes inert gases that are generated onboard the installation for the purpose of providing an inert blanket for onboard oil storage tanks etc.

Vents may contain nitrogen, carbon dioxide, water vapour, hydrocarbons and possibly traces of sulphur compounds, etc. Operators should give an estimated annual average composition of vented stream(s) in the notes section of the vent application.

The following points should be noted:

1. Consents will be issued on a field basis, or where several fields tie-in into common facilities, the operator may apply for a single, composite consent.
2. If a tie back of a new field to an existing facility occurs, the extant vent consent must be varied to include the new field, or a separate vent consent for the new field should be applied for.
3. One field vent consent will continue to cover a field where flaring takes place on a number of installations
4. No carrying forward of vent allowance from one year to the next will be permitted.

5. If it appears that the vent consent will be breached, NEMA (following submittal of a variation to the extant vent consent) will consider issuing a revised consent. It is the operator's responsibility to present a technical case to NEMA in a timely manner (i.e. as soon as it becomes apparent that a breach is likely) in the event that a revision is required.
6. For any application leading to a facility 'total' consent (i.e. the sum of the consents of all fields' producing to the facility) of less than 4 tonnes a day it is sufficient to complete only the minimum of information. However, operators must still exercise appropriate technical and operational diligence in estimating quantities.
7. Any application leading to a facility 'total' consent (i.e. the sum of the consents of all fields' producing to the facility) of greater than 4 tonnes a day will be subjected to detailed review by NEMA. These applications will require the Operator to provide full supporting details and to exercise a high level of technical and operational diligence in estimating quantities.
8. This level of vent is considered to represent a potential opportunity for vent reduction and therefore Operators must submit details of medium- and long-term plans for vent reduction.
9. New fields are subject to normal short-term commissioning vent consents until stable production is achieved, when a decision will be made as to what consent duration will be issued (depending upon vent level sought)

Consent issued by NEMA will specify the vent volume that must not be exceeded over a specified period.

6.3.6 Flaring and Venting Gas Volumes

For existing projects and facilities, flared and vented gas volumes should, at a minimum, be estimated through sound engineering mass and energy balance calculations. It is recommended for new projects and large existing flaring sources that flare volumes be more accurately measured through metering, where possible[51].

This recommendation is consistent with the movement toward implementing best practice as part of continual improvement.

6.3.7 Best Practice Measurement of Flared Gas Volume

To be consistent with best practice, the total volume of gas sent to the flare(s) should be continuously metered either at each of the sources or at the flare headers, to determine the annual volumetric flow to the flare. At a minimum, flow measurement devices used to determine flare gas volumes should have an accuracy of +/- 5 percent over the anticipated range of flow rates[52].

6.3.8 Greenhouse Gas Emissions Estimates

The oil and gas industry, through the American Petroleum Institute (API), has developed an industrywide methodology guideline for GHG emissions estimation. It is therefore recommended that greenhouse gas emissions from associated gas flaring and venting activities be estimated based on the API's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry[53].

6.3.9 Flaring and Venting reporting

It is required that the following information is reported by Operators to NEMA:

- General Information:
    - Company name, address, and contact details
    - Fields within the country over which the organization has operational control and equity interest (%)

[51] A voluntary standard for global gas flaring and venting reduction
http://documents.worldbank.org/curated/en/342761468780614074/pdf/295550GGF0a0pu1ship10no10401public1.pdf
[52] Ibid
[53] API's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, rev 2009, https://www.api.org/~/media/files/ehs/climate-change/2009_ghg_compendium.ashx

- Flaring volumes—total quantity within country boundaries, based initially on an operational control basis and in the future also on an equity share basis:
    - Associated gas flared annual volume
    - Associated gas flared per production annual volume
    - Annual GHG emissions associated with flaring
    - Variance from previous year's flaring data (%)
- Venting volumes—total quantity within country boundaries, based initially on an operational control basis and in the future also on an equity share basis:
    - Annual volume of gas vented
    - Annual volume of gas vented per production
    - Annual GHG emissions associated with venting
    - Variance from previous year's venting data (%)
- Additional reporting to be considered - Forecasts:
    - Forecast flared volumes and greenhouse gas emissions over a five-year period, capturing the anticipated reductions in flaring projected in the Associated Gas Recovery Plan.
    - Forecast vented volumes and GHG emissions over a five-year period.

7. References

International:

- IFC Environmental, Health, and Safety (EHS) General Guidelines, 2007
- IFC environmental, health, and safety guidelines for offshore oil and gas development, June 2015
- IFC environmental, health, and safety guidelines for onshore oil and gas development, April 2017
- IFC environmental, health, and safety guidelines for petroleum refining, November 2017
- EPA Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources, Jan 2916
- EPA Greenhouse Gas Inventory Guidance: Direct Emissions from Mobile Combustion Sources, Jan 2016
- Air Quality Impacts of Petroleum Refining and Petrochemical Industries
- Emission Reduction Techniques for Oil and Gas Activities, U.S. Forest Service 2011
- EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry, 2010
- JRC Reference Report on Monitoring of Emissions to Air and Water from IED Installations, 2017
- AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting, 2018
- A voluntary standard for global gas flaring and venting reduction, World Bank, 2004
- UK guiding note on Flaring and venting during commissioning, Oct 2016
- UK guiding note on Flaring and venting during production, Oct 2016
- API's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, rev 2009

Kenyan:

- National Environment Policy of Kenya 2013
- Ministry of Energy and Petroleum of Kenya, Strategic Environmental and Social Assessment of the Petroleum Sector in Kenya, 2016
- Environmental Management and Co-ordination Act, 1999 rev 2018
- Climate Change Act No. 11 of 2016
- Occupational Safety and Health Act, 2007
- Environmental Management and Coordination (Air Quality) Regulations 2014
- Environmental (Impact Assessment and Audit) Regulations, 2003, rev 2012
- Draft Environmental Management and Coordination (Strategic Assessment, Integrated Impact Assessment and Audit) Regulations, 2018
- Petroleum (Exploration, Development and Production) Act, 2019
- Energy Act, 2019

9. List of Annexes

Annex A Comparative table of Air Quality Standards

The table below provides for Air Quality Standards that are not aligned with the guidelines.

Parameter	Kenya Permissible Limits for Industrial area (First Schedule)	Kenya Permissible Limits for controlled area (First Schedule)	Permissible Limits (WHO, IFC, NAAQS)
Sulphur oxides (SOX)	125 µg/m3-24 hours N/A - Instant Peak (10 min)	30 µg/m3- 24 hours N/A - Instant Peak (10 min)	20 µg/m3(for SO2)- 24 hours 500 µg/m3 (10-minute average) (for SO2)
Nitrogen Dioxide	150 µg/m3 (annual average). 100 µg/m3 (24 hours).	Not specified Not specified	40 µg/m3 (annual average) 200 µg/m3 (10 minutes)
PM_{10}	70 µg/m3 (annual average). 150 µg/m3 (24 hours).	50 µg/m3 (annual average) 75 µg/m3 (24 hours)	20 µg/m3 (annual average) 50 µg/m3 (24 hours)
$PM_{2.5}$	35 µg/m3 (annual average). 70 µg/m3 (24 hours).	Not specified Not specified	10 µg/m3 (annual average). 25 µg/m3 (24 hours).
Lead (Pb)	1.0 µg/m3 (annual average).	0.5 µg/m3 (annual average).	0.15 µg/m3 (3-month average).
Carbon monoxide (CO)/carbon dioxide (CO2)	5 µg/m3 (annual average). 10 µg/m3 (1 hour).	1 µg/m3 (annual average). 2 µg/m3 (1 hour).	9 ppm (8-hour average) 35 ppm (1hour average)
Hydrogen Sulphide	150 µg/m3 (24 hours).	Not specified	5 mg/Nm3
Ozone	200 µg/m3 (1 hour). 120 µg/m3 (8 hours peak).	Not specified	N/A 100 µg/m3 (8-hour max).

Ref:

- IFC Environmental, Health, and Safety General Guidelines
- IFC Environmental, Health, and Safety Guidelines for Offshore Oil and Gas Development
- IFC Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development
- US National Ambient Air Quality Standards

Annex B

Air Emission Limits for Refining Facilities

The table below provides for Air Emission Limits that are not aligned with the guidelines

Air Emissions Limits for Petroleum Refining Facilities a			
Pollutant	**Units**	**Kenya Emission limits**	**Guideline Value as per IFC guidelines**
NOX [b]	mg/Nm3	460	300 100 for FCCU
SOX [c]	mg/Nm3	Sulphur Recovery: 150 Combustion unit: 500	150 for SRU; 300 for FCCU 500
Particulate Matter (PM10)[d]	mg/Nm3	50	25
Vanadium [e]	mg/Nm3	x	5
Nickel	mg/Nm3	x	1
H2S [e]	mg/Nm3	152	5

a. Dry gas at 3 percent O2

b. NOx means NO+NO2 expressed in NO2 equivalent. Guideline value from European Commission Joint Research Center (EC JRC), “Best Available Techniques Reference (BREF) Document for the Refining of Mineral Oil and Gas” (2015)

c. SOx means SO2 + SO3 expressed in SO2 equivalent

d. Guideline value from EC JRC, “BREF Document for the Refining of Mineral Oil and Gas” (2015). Particulate matter guideline value is also valid for FCCU

e. From G.S.R. 186(E) and 820(E), India Ministry of Environment and Forests Notification

Ref:

- IFC Environmental, Health, And Safety Guidelines for Petroleum Refining

Annex C

List of reference documents that provide for technologies, techniques and standards for emission control and reduction in the upstream petroleum sector

1. IFC Environmental, Health, And Safety Guidelines For Offshore Oil And Gas Development
   https://www.ifc.org/wps/wcm/connect/f3a7f38048cb251ea609b76bcf395ce1/FINAL_Jun+2015_Offshore+Oil+and+Gas_EHS+Guideline.pdf?MOD=AJPERES

2. IFC Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development
   https://www.ifc.org/wps/wcm/connect/4504dd0048855253ab44fb6a6515bb18/Final%2B-%2BOnshore%2BOil%2Band%2BGas%2BDevelopment.pdf?MOD=AJPERES&id=1323153172270

3. IFC Environmental, Health, and Safety Guidelines for Natural Gas Processing
   https://www.ifc.org/wps/wcm/connect/7a68040048855301ad34ff6a6515bb18/Final%2B-%2BNatural%2BGas%2BProcessing.pdf?MOD=AJPERES&id=1323153249182

4. IFC Environmental, Health, And Safety Guidelines For Liquefied Natural Gas Facilities
   https://www.ifc.org/wps/wcm/connect/edb102c5-ca61-4561-8b8e-8124fa2060af/20170406-FINAL+LNG+EHS+Guideline_April+2017.pdf?MOD=AJPERES

5. IFC Environmental, Health, and Safety General Guidelines
   https://www.ifc.org/wps/wcm/connect/554e8d80488658e4b76af76a6515bb18/Final%2B-%2BGeneral%2BEHS%2BGuidelines.pdf?MOD=AJPERES

6. Cold venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities (Module 3A report). Best available technique (BAT) assessments. Prepared for the Norwegian Environment Agency
   https://www.miljodirektoratet.no/Documents/publikasjoner/M665/M665.pdf

7. World Resource Institute: Reducing Methane Emissions from Natural Gas Development: Strategies For State-Level Policymakers, Working Paper
   https://www.wri.org/sites/default/files/reducing-methane-us-working-paper.pdf

8. Emission Sources and Control Technologies Affecting Upstream and Midstream Oil and Gas
   https://www.bryancave.com/images/content/2/0/v2/2004/2-LondonChristopher-ControlTechnologies-COMPLETE.pdf

Annex D

List of additional reference documents that provide for advanced technologies for emission control and reduction strategies

1. IFC Environmental, Health, And Safety Guidelines for Petroleum Refining
   https://www.ifc.org/wps/wcm/connect/df09eb23-f252-4d08-ac86-db1972c781a7/2016-EHS+Guidelines+for+Petroleum+Refining+FINAL.pdf?MOD=AJPERES

2. IFC Environmental, Health, and Safety General Guidelines
   https://www.ifc.org/wps/wcm/connect/554e8d80488658e4b76af76a6515bb18/Final%2B-%2BGeneral%2BEHS%2BGuidelines.pdf?MOD=AJPERES

3. EU Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas (Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control)
   http://eippcb.jrc.ec.europa.eu/reference/BREF/REF_BREF_2015.pdf

4. World Resource Institute: Reducing Methane Emissions from Natural Gas Development: Strategies For State-Level Policymakers, Working Paper
   https://www.wri.org/sites/default/files/reducing-methane-us-working-paper.pdf

5. Emission Sources and Control Technologies Affecting Upstream and Midstream Oil and Gas
   https://www.bryancave.com/images/content/2/0/v2/2004/2-LondonChristopher-ControlTechnologies-COMPLETE.pdf

6. Best available techniques guidance document on oil and gas industry
   http://www.doe.gov.my/portalv1/wp-content/uploads/2014/07/BEST-AVAILABLE-TECHNIQUES-GUIDANCE-DOCUMENT-ON-OIL-AND-GAS-INDUSTRY.pdf

Annex E

Measurement protocols

Parameter	Monitoring (frequency)[54]	Measurement Protocol[55] under Kenya Regulations	Alternative/Additional Measurement Standards under international best practice
Sulphur oxides (SO_X)	Annual / Quarterly (refineries)	• KS ISO 11632: Stationary source emissions --Determination of mass concentration of sulfur dioxide --Ion chromatography method • KS ISO 6767: Ambient air --Determination of the mass concentration of sulfur dioxide --Tetrachloromercurate (TCM)/pararosaniline method • KS ISO 4219: Air quality -Determination of gaseous Sulphur compounds in ambient air -Sampling equipment • KS ISO 4221: Air quality -Determination of a mass concentration of Sulphur dioxide in ambient air -Thorin spectrophotometric method • KS ISO 7934: Stationary source emissions -Determination of the mass concentration of Sulphur dioxide -Hydrogen peroxide / barium perchlorate –Thorin method	• BS EN 14212:2012 Ambient air. Standard method for the measurement of the concentration of sulphur dioxide by ultraviolet fluorescence • Alaska Department of Environmental Conservation, *Standard Procedures for Sulfur Dioxide (SO_2) Monitoring by Ultraviolet Fluorescence* (2012). • Canadian Council of Ministers, *Ambient Air Monitoring Protocol for $PM_{2.5}$ and Ozone* (2011) • McLinden et al, *Space-based detection of missing sulfur dioxide sources of global air pollution* (2016).
Oxides of Nitrogen (NO_X)	Annual / Quarterly (refineries)	• KS ISO 7996: Ambient air --Determination of the mass concentration of nitrogen oxides --Chemiluminescence method	• Canadian Council of Ministers, *Ambient Air Monitoring Protocol for PM2.5 and Ozone* (2011) • BS EN 14211:2012 Ambient air. Standard method for the measurement of the concentration of nitrogen dioxide and nitrogen monoxide by chemiluminescence (2012)
Nitrogen Dioxide	Annual / Quarterly (refineries)	• KS ISO 10849: Stationary source emissions --Determination of the mass concentration of nitrogen oxides --Performance characteristics of automated measuring systems • KS ISO 11564: Stationary source emissions --Determination of the mass concentration of nitrogen oxides --Naphthylethylenediamine photometric method	• Canadian Council of Ministers, *Ambient Air Monitoring Protocol for PM2.5 and Ozone* (2011) • BS EN 14211:2012 Ambient air. Standard method for the measurement of the concentration of nitrogen dioxide and nitrogen monoxide by chemiluminescence (2012)
Suspended Particulate matter (SPM)	Annual / Quarterly (refineries)	Kenyan law provides no reference.	• ISO 9835:1993(en) Ambient air - Determination of a black smoke index
PM_{10}	Annual / Quarterly (refineries)	• KS ISO 12141: Stationary source emissions --Determination of mass concentration of Particulate matter (dust) at low	• EN 12341:2014 Ambient air - Standard gravimetric measurement method for the determination of the PM10 or PM2,5 mass

[54] Water Quality Regulations § 14; Air Quality Regulations, § 19, 68, Fourteenth Schedule.
[55] https://www.concawe.eu/wp-content/uploads/2017/01/report-no.-4_13.pdf ; Air Quality Regulations, Eleventh Schedule.

		concentrations --Manual gravimetric method	concentration of suspended particulate matter
$PM_{2.5}$	Annual / Quarterly (refineries)	• KS ISO 12141: Stationary source emissions --Determination of mass concentration of Particulate matter (dust) at low concentrations --Manual gravimetric method	• Canadian Council of Ministers, Ambient Air Monitoring Protocol for PM2.5 and Ozone (2011) • EN 12341:2014 Ambient air - Standard gravimetric measurement method for the determination of the PM10 or PM2,5 mass concentration of suspended particulate matter.
Lead (Pb)	Annual / Quarterly (refineries)	• KS ISO 9855: Ambient air - Determination of the particulate lead content of aerosols collected on filters -Atomic absorption spectrometric method	• US Code of Federal Regulations, Tittle 40, Chapter I, Subchapter C, Part 50, Appendix G Reference Method for the Determination of Lead in Total Suspended Particulate Matter
Carbon monoxide (CO)/carbon dioxide (CO2)	Annual / Quarterly (refineries)	• KS ISO 12039: Stationary source emissions --Determination of carbon monoxide, carbon dioxide and oxygen --Performance characteristics and calibration of automated measuring systems. • KS ISO 8186: Ambient air --Determination of the mass concentration of carbon monoxide --Gas chromatographic method.	• BS EN 14626:2012 Ambient air. Standard method for the measurement of the concentration of carbon monoxide by non-dispersive infrared spectroscopy • Canadian Council of Ministers, Ambient Air Monitoring Protocol for PM2.5 and Ozone (2011)
Hydrogen Sulphide	Annual / Quarterly (refineries)	• KS ISO 4219: Air quality - Determination of gaseous Sulphur compounds in ambient air -Sampling equipment	• Canadian Association of Petroleum Producers, *Guideline on H_2S Release Rate Assessment and Audit Forms* (2012). • *Hydrogen Sulfide in Gases by the Tutweiler Method*, UOP Method 9-59, Universal Oil Products Company, Des Plaines, Illinois, USA, 1959. • *Test for Hydrogen Sulfide in LPG and Gases (Tutweiler Method)*, Plant Operations Test Manual, Gas Processor's Association (GPA), 1812 First Place, Tulsa, Oklahoma. • *Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes*, Adopted as a tentative standard in 1997 by the Gas Processors Association, GPA publication 2377-77. • *Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes*, ASTM Designation D 4810-88 (re-approved 1994). • *Influence of Containers on Sour Gas Samples*, J.G.W. Price & D.K. Cromer, Petroleum Engineer International, March, 1980.
Non-methane hydrocarbons	Annual / Quarterly (refineries)	**Under Kenyan Law** Kenyan law provides no reference.	• ISO 14965:2000: Air quality -- Determination of total non-methane organic compounds -- Cryogenic pre-concentration and direct flame ionization detection method • US EPA, Ambient Air Non-Methane Hydrocarbon Monitor

Total VOC	Annual / Quarterly (refineries)	**Under Kenyan Law** • KS ISO 16200-1: Workplace air quality --Sampling and analysis of volatile organic compounds by solvent desorption/gas chromatography --Part1: Pumped sampling method • KS ISO 16200-2: Workplace air quality --Sampling and analysis of volatile organic compounds by solvent desorption/gas chromatography --Part2: Diffusive sampling method • KS ISO 16000-5: Indoor air --Part5: Sampling strategy for volatile organic compounds (VOCs) • KS ISO 16000-6: Indoor air --Part6: Determination of volatile organic compounds in indoor and test chamber air by active sampling on Tenax TA sorbent, thermal desorption and gas chromatography using MS/FID • KS ISO 16000-9: Indoor air --Part9: Determination of the emission of volatile organic compounds from building products and furnishing --Emission test chamber method • KS ISO 16000 -10: Indoor air --Part10: Determination of the emission of volatile organic compounds from building products and furnishing --Emission test cell method • KS ISO 16000-11: Indoor air --Part11: Determination of the emission of volatile organic compounds from building products and furnishing --Sampling, storage of samples and preparation of test specimens • KS ISO 16017-1: Indoor, ambient and workplace air –Sampling and analysis of volatile organic compounds by sorbent tube/thermal desorption/capillary gas chromatography --Part1: Pumped sampling • KS ISO 16017-2: Indoor, ambient and workplace air --Sampling and analysis of volatile organic compounds by sorbent tube/thermal desorption/capillary gas chromatography --Part2: Diffusive sampling	• Canadian Council of Ministers, Ambient Air Monitoring Protocol for PM2.5 and Ozone (2011) • US EPA, Method 18 - Volatile Organic Compounds by Gas Chromatography • US EPA, Method TO-17 Determination of Volatile Organic Compounds in Ambient Air Using Active Sampling Onto Sorbent Tubes

Ozone	Annual / Quarterly (refineries)	**Under Kenyan Law** • KS ISO 10313: Ambient air -- Determination of the mass concentration of ozone -- Chemiluminescence method • KS ISO 13964: Air quality -- Determination of ozone in ambient air --Ultraviolet photometric method	• BS EN 14625:2012 Ambient air. Standard method for the measurement of the concentration of ozone by ultraviolet photometry • Canadian Council of Ministers, Ambient Air Monitoring Protocol for PM2.5 and Ozone (2011)

Annex F

Indicative list of Performance Standards for Flaring and Venting

These requirements apply to flares in all upstream oil and gas industry systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing.

Flare systems include associated separation equipment, piping, and controls. In these sections, some requirements are specific to the type of equipment used, and this is specified in those requirements.

Although some design or operating specifications are provided, this is not a substitute for comprehensive engineering design codes and guidelines. It identifies minimum requirements but is not intended as a comprehensive design manual.

1) Petroleum company must ensure that a qualified technical professional is responsible for the design or review of flare systems, including separation, related piping, and controls, and for the specification of safe operating procedures.

2) Petroleum company must ensure that operating procedures that define the operational limits of flare systems are documented and implemented and that these procedures meet the design requirements.

- Operating limits and procedures must be provided to NEMA immediately upon request.
- Flare systems must be operated within the operational ranges and types of service specified by the designing or reviewing engineer, technician, or technologist. If this equipment is used for emergency shutdowns, this must be considered in the design.

3) If using, in a field service, a flare that has not previously been field tested, petroleum company must be able to provide actual monitoring data to show that performance specifications will be met.

- Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted, or unless the facility is capable of being shut in if problems arise.

4) ANSI/API Standard 521: Pressure-Relieving and Depressuring Systems, as well as applicable fire safety codes, electrical codes, CSA standards, and mechanical engineering standards, are all necessary references for the design of gas combustion systems.

5) Petroleum company must comply with Kenya safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures (see Pressure Equipment Safety Regulation).

6) NEMA recommends that petroleum companies use best engineering practices, as well as appropriate engineering codes and standards, in the design and operation of flare systems.

Further indicative standards are summarised in S.7 of AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting (https://www.aer.ca/documents/directives/Directive060_2020.pdf)

10. Revision Matrix:

Revision	Date	Purpose	Prepared by	Reviewed/Approved
Draft	19/02/2019	Issued for review	IHS Markit/ESAL	NEMA
Final Draft	05/04/2019	Issued for approval	IHS Markit/ESAL	NEMA
Revised Final Draft	16/01/2020	Aligned with approved review report	IHS Markit/ESAL	NEMA
Additionally revised Final Revised	10/03/2020	Aligned with client comments	IHS Markit/ESAL	NEMA