# GUIDELINES FOR MANAGEMENT OF GREEN HOUSE GASES (GHG) AND FUGITIVE EMISSIONS FROM MIDSTREAM AND DOWNSTREAM PETROLEUM OPERATIONS IN NIGERIA

## ISSUED BY

## NIGERIAN MIDSTREAM AND DOWNSTREAM PETROLEUM REGULATORY AUTHORITY (NMDPRA)

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## Foreword

Climate change and environmental sustainability remain some of the most pressing challenges facing humanity. As the world confronts the long-term consequences of industrialization and energy consumption, the role of the oil and gas sector in advancing global climate goals has become increasingly vital. Our collective future depends on the choices we make, and the responsibility to act decisively and innovatively is one we must all share.

Nigeria has long recognized the importance of reducing greenhouse gas (GHG) emissions and transitioning toward a more sustainable energy future. Following its commitment under the Paris Agreement, the country has embarked on a multi-sectoral approach to climate action. Central to this effort is the implementation of strategies aimed at reducing emissions, including the adoption of the National Action Plan on the reduction of Short-Lived Climate Pollutants (SLCPs), as part of its broader Nationally Determined Contributions (NDCs).

In support of these national objectives, and pursuant to the provisions of the Petroleum Industry Act (PIA), the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) has introduced a suite of regulatory instruments. These include the Midstream and Downstream Petroleum Environmental Regulations (MDPER), the Midstream Gas Flare Regulation (MGFR) and the Midstream and Downstream Petroleum Safety Regulations (MDPSR), alongside various guidelines, policies, and administrative directives. These tools serve to strengthen industry accountability, improve environmental performance, and facilitate Nigeria's path toward achieving its climate targets, including the aspiration of Net Zero emissions.

To further enable the practical implementation of these regulatory frameworks, the Guidelines for the Management of Greenhouse Gases (GHGs) and Fugitive Emissions in the Midstream and Downstream petroleum sectors have been developed. These

Guidelines are intended to support operators in minimizing emissions, improving energy efficiency, and aligning operations with global best practices in environmental stewardship.

The NMDPRA acknowledges the contributions of all stakeholders, experts, and institutions that have supported the development of this important resource, which reinforces our shared commitment to a more sustainable and responsible energy future.

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# 1.0 OVERVIEW

## 1.1 Climate Change

Climate change is one of the most critical challenges facing the global community. Driven by the accumulation of greenhouse gases (GHGs) in the atmosphere, its effects are far-reaching, impacting ecosystems, human health, economies, and national security. In the petroleum industry, particularly in Nigeria, activities such as gas flaring and venting contribute to GHG emissions. These emissions not only bring about environmental degradation but also lead to public health risks and notable economic losses due to wasted resources.

Recognizing these risks, decisive steps to mitigate the impacts of climate change have been taken globally. One of such of critical importance is the Paris Agreement, adopted in 2015 and ratified by Nigeria in 2016. This accord commits nations to limit global temperature rise to well below 2°C above pre-industrial levels, while pursuing efforts to constrain it further to 1.5°C. Recent global summits, including the UNFCCC Conference of Parties (COP), of which Nigeria is a party, have reaffirmed the urgency of achieving these temperature goals, especially for vulnerable regions such as sub-Saharan Africa.

The Paris Agreement emphasizes adaptation, mitigation, technology transfer, capacity building, and climate finance, placing obligations on all countries, not just industrialized nations. Under this framework, countries must submit Nationally Determined Contributions (NDCs), which outline specific emission reduction strategies and are subject to regular review and reporting cycles.

Nigeria's NDCs reflect its commitment to a low-carbon development pathway, and the petroleum industry is a critical component of this transformation. As an emitter, the

industry must implement robust environmental controls and innovative practices to align with global and national climate targets.

### 1.2 Greenhouse Gas (GHG) Emissions and the National Context

GHG emissions in Nigeria arise from a wide range of economic activities, including energy production, transportation, agriculture, manufacturing, waste management, and mining. While the oil and gas sector is a primary contributor, meaningful emissions reduction cannot be achieved by one sector alone. A coordinated, cross-sectoral approach is essential to achieving Nigeria's declared goal of Net Zero emissions by 2060.

Particular attention has been given to Short-Lived Climate Pollutants (SLCPs) such as Methane ($CH_4$) and Black Carbon (BC), which despite their shorter atmospheric lifespans, have disproportionately high warming potential and severe health impacts. In response, Nigeria has developed a National SLCP Action Plan (NAP) to identify emission sources, evaluate mitigation options, and prioritize interventions. Though Carbon Dioxide ($CO_2$) is a long-lived GHG, its abundance due to industrial and natural processes requires parallel management alongside SLCPs.

As at the time of this publication, 22 mitigation measures have been defined across eight sectors namely, Oil & Gas, Transport, Agriculture, Power/Energy, Residential, Manufacturing, Waste Management, and Industry. These measures are aligned with broader national strategies which include:

- Nigeria's Nationally Determined Contributions (NDCs),
- The Nigeria Energy Transition Plan,
- The Nigeria Climate Change Response Programme, amongst others.

Together, these initiatives represent a comprehensive framework to decarbonize the economy while fostering sustainable growth.

### 1.3 Objectives

These Guidelines are issued to provide a standardized framework for the management of GHG and fugitive emissions in the Midstream and Downstream petroleum sectors. The guidelines outline technical procedures, operational protocols, and regulatory expectations that a licensee or permit holders shall adopt for the prevention and control of GHG and fugitive emissions from Midstream and Downstream petroleum operations.

The primary objectives are to:

i. Minimize the environmental and social impacts of GHG and fugitive emissions in line with Nigeria's NDCs and international climate obligations.

ii. Promote conservation of natural resources by reducing gas losses, preventing unnecessary flaring or venting, and encouraging energy efficiency.

iii. Enhance health, environmental safety, and operational integrity through structured monitoring, mitigation, and reporting practices.

These Guidelines are applicable to new and existing facilities involved in Midstream and Downstream Petroleum Operations in Nigeria. By enforcing these provisions, the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) seeks to ensure environmental compliance, reduce Nigeria's emissions footprint, and contribute meaningfully to the global effort to limit climate change.

### 1.4 Legal Framework

These Guidelines are issued pursuant to the powers conferred on the NMDPRA under the Petroleum Industry Act, 2021 and the Regulations made thereof.

# 2.0 OVERVIEW OF GREEN HOUSE GAS (GHG) EMISSIONS

## 2.1 Emission Sources and Management

All GHG emissions specifically, Methane ($CH_4$), Carbon dioxide ($CO_2$) and Nitrous Oxide ($N_2O$), are potent gases with significant implications for climate change. Although $CH_4$ has a much shorter atmospheric lifetime than $CO_2$, about 12 years compared with centuries for $CO_2$, it absorbs much more energy while in the atmosphere. Thus, while $CH_4$ tends to receive less attention than $CO_2$, reducing energy-sector $CH_4$ emissions will be critical for avoiding the worst effects of climate change due to its higher Global Warming Potential (GWP).

Natural gas and petroleum systems are the second largest source of $CH_4$ emissions into the environment. $CH_4$ is the primary component of natural gas, which is emitted into the atmosphere during oil & gas production, processing, storage, transmission, and distribution. The key activities that emit $CH_4$ in the petroleum industry include gas flaring, venting, fugitive emissions and leaks from pipelines, process equipment etc. Fugitive emissions and leaks occur through equipment such as, compressors, pneumatics controllers & pumps, glycol dehydrators, valves/flanges, vents of storage tanks, flares etc.

Management of GHG emissions successfully, requires adopting a comprehensive approach and action on all fronts to address the urgency of climate change. This approach constitutes the elimination, reduction, substitution and compensation of unavoidable residual emissions as a last option of these gases.

## 2.2 Compliance Directive

A licensee or permit holder shall comply with the following to reduce and/or eliminate GHG and fugitive emissions from its activities or operations:

2.2.1 Ensure during the design, modification, installation or decommissioning of its facilities, the submission of a GHG Management Plan for approval towards the issuance of the applicable license.

2.2.2 For existing facilities,

a) Develop and submit a GHG Management Plan within six (6) months from the effective date of these Guidelines for approval or

b) Update any previously approved/submitted GHG management Plan to reflect material changes in operations, equipment, emission sources or other relevant parameters and submit within six (6) months from the effective date of these Guidelines for approval.

2.2.3 The GHG Management Plan shall include the following:

c) The scope of operation and emission sources

d) An inventory of all equipment that generate GHG. The inventory of equipment shall comply with the provisions of the relevant GHG reporting requirements in Section 4.2.

e) Established baseline emission data with a base year, guided by historical dataset, against which all future GHG emissions shall be compared.

f) Techniques/procedures for emission quantification and accounting.

g) Strategies to reduce GHG emissions to attain net-zero, indicating annual percentage reduction targets.

h) Provide a timeline to replace single cycle gas turbines with a combined cycle by 2030, for existing facilities. Use of combined cycle turbines shall be implemented immediately for new projects.

i) Strategies to achieve at least 2.5% per year reduction in GHG intensity (refer to *Appendix I(e)*).

2.2.4 Ensure the retrofitting of equipment or installation of new equipment as applicable, in line with the provisions of Section 3 of these Guidelines.

2.2.5 Ensure adequate monitoring of activities/operations that emit GHG, especially venting, flaring, fugitive emissions/leaks from process equipment and gas transmission pipelines.

2.2.6 Establish a system for identifying, classifying, and quantifying GHG emissions from its activities or operations.

2.2.7 Ensure submission of GHG monitoring reports quarterly, by the first week of the succeeding month, to the Authority.

# 3.0 GHG EMISSION CONTROL, MITIGATION AND MONITORING REQUIREMENTS

## 3.1 Control and Inspection Requirements

3.1.1 For existing facilities, inspections shall be conducted within 90 days of publication of these guidelines, and for new facilities, inspections shall be conducted within 90 days after commencement of operations.

3.1.2 Monitoring leaks or emissions from operations shall be applicable to hydrocarbon processing facilities such as refineries, petrochemical plants, and also to gas export Terminals, blending plants, emulsion processing facilities, product depots & gas storage, industrial gas storage & utilization facilities, waste management facilities, and any other facility as may be determined by the Authority.

## 3.2 Leak Detection and Repair (LDAR) Programme

3.2.1 LDAR shall entail identifying emitting equipment/components, quantifying and classification of emissions, addressing the leaks and institution of a prevention and control measure.

3.2.2 A licensee or permit holder shall adopt one or both of the following options for the programme, using technologies or methodologies approved by the Authority:

a) Conduct surveys in-house.

b) Contract third-party service provider(s) accredited by the Authority to conduct inspection surveys.

3.2.3 The Authority shall participate periodically in the LDAR programme and issue certificates of validation to licensees or permit holders.

3.2.4 Inspection Frequency

a. ***Onshore Facilities:***

i. A licensee or permit holder shall conduct one inspection at each facility within 12 months of this Guideline coming in effect.

ii. After 24 months of implementation of these guidelines, a licensee or permit holder shall be expected to conduct two inspections at each facility, with each inspection performed at least 5 months after the previous inspection.

iii. Within 36 months and subsequently, a licensee or permit holder shall conduct four inspections at each facility, with each inspection performed at least 2 months after the previous inspection.

b. ***Offshore Facilities***

i. Inspection frequency for manned offshore platforms shall be the same as for onshore facilities.

ii. Inspections shall be conducted for unmanned offshore platforms whenever on-site maintenance activities are planned, up to the frequency schedule outlined for onshore facilities.

iii. If planned maintenance does not occur in a particular year, a licensee or permit holder shall notify the Authority in writing providing reasons.

c. Notwithstanding the above provisions for gas storage and retailing facilities, especially LPG, propane and butane, the frequency for inspection shall be bi-annually or as determined by the Authority.

3.2.5 Requirements for Inspection

A licensee or permit-holder shall ensure that:

a) Each inspection survey takes cognizance of *Fugitive Emissions Components* such as valves, pipes, gauges, gaskets, tank thief hatches, thread connections, drains, screw and compressor fittings, compressor gaskets, flanges, pump seals, compressor components, meters, malfunctioning pneumatic devices etc.

b) Inspections are conducted in line with approved organisational and site-specific fugitive emission inspection plans, as prescribed in Section 3.2.5(b).

c) Inspection includes observation of flare stack. The condition of flare stack, which shall include the structural integrity, aesthetics, pitting or corrosion etc. shall be noted and documented. The state of the flare shall be described as either:

   i. Lit flare- adequate combustion.

   ii. Lit- poor combustion (sputtering, smoking, etc.)

   iii. Unlit flare with gas vent

   iv. Unlit flare with no gas vent.

d) Where the flare is found to be "*unlit with gas vent*", re-ignition (repair) of the flare is required within 48 hours. If the duration of repair exceeds 6 hours without re-ignition, a licensee or permit holder shall notify the Authority immediately.

e) Where flare is sputtering or smoking, a new flare tip shall be installed, adding liquids knockouts upstream of the flare, or other appropriate interventions. However,

   i. Within the first 2 years following implementation of these Guidelines, a licensee or permit- holder has 18 months to replace flare tip or conduct other appropriate interventions.

ii. After this initial two (2) year period, any sputtering or smoking flare shall be addressed within 60 days of detection.

f. The provisions of e (i - ii) do not substitute for the annual flare control test as prescribed in Section 3.4.2.

g. Audio, Visual, and Olfactory (AVO) inspection shall be conducted daily, weekly or monthly as required by the organisation's monitoring plan.

3.2.6 Requirements for Repair:

A licensee or permit holder shall attempt first repair within these periods:

a) Leaks equal to or greater than 50,000 parts per million (ppm) by volume, categorised as *Large Leaks,* shall be repaired within 5 working days of detection.

b) Leaks less than 50,000ppm by volume, categorised as *Small Leaks,* shall be repaired within 14 days of detection.

3.2.6.1 Fugitive emissions component shall be considered repaired when:

a. Emissions cannot be detected by infra-red camera or any other detection technology.

b. A concentration of hydrocarbons below 500 ppm or emissions not detected by EPA Method 21.

3.2.6.2 For a critical component that cannot be repaired without shutdown, the leak shall be minimized within 24 hours of detection by the licensee or permit holder and a repair scheduled by the end of the next planned process shutdown or within 12 months,

3.2.7 Re-Inspection and Reassessment Requirements

A licensee or permit holder shall reinspect each repaired or replaced component of a leaking equipment/pipeline as soon as practicable or within 15 days after the repair or replacement to confirm the successful elimination of leaks. A reassessment of the component's emission potential and maintenance history shall be performed to ensure ongoing compliance and to reduce the likelihood of future fugitive emissions.

3.2.8 Organisational and Site-Specific Fugitive Emissions Inspection Plan

A licensee or permit holder shall submit its company's fugitive emissions inspection plan, within180 days from the effective date of these Guidelines. The Inspection Plan shall contain a *General Plan and Site-Specific Plan,* where required. The Inspection Plan shall include the following elements:

*a. General Site Plan*

i. Manufacturer's name and specification of fugitive emissions detection equipment to be used.

ii. Methods and schedules for identifying and repairing components from which fugitive emissions are detected, including fugitive emission components that are unsafe to repair.

iii. Methods and schedules for verifying fugitive emission component repairs.

*b. Specific Site Plan*

For site-specific fugitive emissions, the inspection plan shall include the following elements:

i. A sitemap.

ii. Deviations from approved organisational fugitive emission inspection plan.

iii. A defined *Walking Path* that accounts for interferences and ensures all fugitive emissions components are within site of the path.

iv. Other plan components shall be acceptable based on site-specific requirements.

c. *Monitoring Survey Records*

Each monitoring survey records shall include the following:

i. Date

ii. Duration

iii. Name of licensee or permit holder, the third-party service provider performing survey, including relevant training and experience.

iv. Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

v. A statement of any deviations or otherwise from the monitoring plan.

vi. The state of each flare flame observed and recorded.

vii. Successful repair date of fugitive emissions components.

viii. Details of the instrument used to resurvey a repaired fugitive emissions component.

3.2.9 Technology/Equipment Verification

Any leak detection technology for fugitive emissions to be deployed shall be verified as follows:

a) Verification checks shall be carried out when leak detection survey is to be performed prior to the commencement of the inspection in line with the manufacturer's specifications for the instrument and shall include:

i. Methodology for determining the maximum viewing distance from equipment and how the licensee or permit holder will ensure maintenance of this distance.

ii. Methodology for determining the maximum wind speed at which monitoring shall be performed and ensure its implementation below this threshold.

b. Procedures for conducting surveys by licensee or permit holder shall include the following:

i. Ensure the adequacy of a thermal background to view potential fugitive emission.

ii. Taking into consideration diverse monitoring conditions and interferences such as wind and steam.

c. Personnel shall have the requisite training and experience in the use of equipment prior to performing surveys.

d. Calibration and maintenance shall be in line with manufacturers' recommendation.

3.2.10 Reporting

a) A licensee or permit holder shall submit an annual report not later than 90 days of the preceding year. The report shall contain as a minimum the total number of the following:

i. Inspections conducted,

ii. Facilities inspected,

iii. Leaks identified by component and type of facility,

iv. Leaks repaired, and

v. Leaks on delayed repair list, accompanied by certification of the truth, accuracy and veracity of the report signed by a competent person(s).

vi. Type of survey conducted, in-house or third party (provide details of consultant)

b. The flare notation for each site shall be reported.

## 3.3 Cold Venting

### 3.3.1 Prohibition and Regulatory Alignment

Cold venting is prohibited in the Nigerian Midstream and Downstream Petroleum industry in line with the provisions of the Midstream Gas Flare Regulation 2023.

### 3.3.2 Operational Exigencies and Permits

Provided a licensee or permit holder is granted a permit to vent natural gas due to operational exigencies, the Control Requirements in *Section 3.3.3* shall apply.

### 3.3.3 Control Requirements

a. The root cause of gas being sent to a cold vent stack shall be addressed by the licensee or permit holder. These shall include steps taken to minimize equipment venting from operations pursuant to Sections 3.5 to 3.10 of these Guidelines and minimizing fugitive emissions pursuant to Section 3 of these Guidelines.

b. Any residual venting shall be routed to a flare, except one of the following conditions exist:

i. Nonflammable gas mixture.

ii. Unstable flame occasioned by low gas volume or pressure for the flare design.

3.3.4 Data Management

A licensee or permit-holder shall keep records of all equipment generating emissions from each vent, including detailed documentation of venting operations from pressure vessels, pipelines, and storage tanks, capturing gas composition, volume, duration, and reason for release.

3.3.5 Reporting

A licensee or permit-holder shall submit an annual report demonstrating compliance and record of any deviations, accompanied by certification of the truth and accuracy of report signed by a competent person, not later than the first quarter of the preceding year.

## 3.4 Flare Efficiency

3.4.1 Operational Requirements

Any gas flared shall be combusted in an auto-igniter or continuous pilot light with a design Destruction Removal Efficiency (DRE) of at least 98% for hydrocarbons. Calculation of 98% DRE shall not include flare downtime for maintenance.

3.4.2 Monitoring

A licensee or permit-holder shall conduct the annual test of the auto-igniter to ensure:

a. Its operability or the annual observation of continuous pilot light to ensure it is independently lit.

b. The flare at the time of LDAR inspection is observed, to confirm if it is lit or not.

3.4.3 Data Management

A licensee or permit-holder shall keep records of:

a. Annual flare efficiency test.
b. Any observed instance of unlit flare with venting gas.

3.4.4 Reporting

A licensee or permit-holder shall submit not later than 90 days of the preceding year, records for the annual test/observation and unlit flares.

## 3.5 Pneumatic Controllers

3.5.1 Requirements for Control

a. All-natural gas-driven pneumatic controllers of processing plants, gas downloading and compression stations, shall be retrofitted with zero bleed controllers. Controllers powered by electricity, instrument air or emissions(gas emissions captured and used for energy), shall be routed to a *Vapor Recovery System*. Where it is not feasible to capture the emissions, a licensee or permit holder may route to a flare.
b. All existing facilities with pneumatic controllers shall implement a five (5) year phase-out strategy as follows:
    i. Within one year of implementation of these guidelines, licensee or permit holder shall ensure that 25% of these pneumatic controllers are zero bleed controllers, and the remaining are low bleed controllers that emit less than 0.17 standard cubic meters per hour of natural gas.
    ii. Within two years of implementation of these guidelines, licensee or permit holder shall ensure that 65% of these pneumatic controllers are zero-bred controllers and the remaining are low bleed controllers.

iii. Within three years of implementation of these guidelines, a licensee or permit holder shall ensure that 75% of these pneumatic controllers are zero-bleed controllers and the remaining are low bleed controllers.

iv. Within four years of implementation of these guidelines, a licensee or permit holder shall ensure that 85% of these pneumatic controllers are zero bleed controllers, and the remaining are low-bleed.

v. Within five years of implementation of these guidelines, licensee or permit holder shall ensure that all pneumatic controllers are zero bleed controllers.

c. All new facilities shall ensure the installation of only zero bleed pneumatic controllers

3.5.2 Monitoring

A licensee or permit holder shall ensure any gas-driven pneumatic controller in its facility is:

a. Tested annually using a direct measurement method which may include high volume sampling, bagging and calibrated flow measuring instrument.

b. Measured for any leaks and documented. Where the emission rate is greater than 0.17 standard cubic meters per hour, the device shall be repaired within 14 days of detecting the leak.

c. Monitored to ensure that no emissions occur between actuations by using relevant instruments during any inspection conducted within 90 days after startup for new facilities, and within 90 days of enactment of these guidelines for other facilities. If emissions occur between actuations, the controller shall be fixed or replaced within 30 days.

3.5.3 Data Management

Natural gas bleed rate shall be recorded and maintained for at least 5 years. Where bleed rate is zero, the type of pneumatic controller shall be documented and maintained for 5 years.

3.5.4 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the preceding year, demonstrating compliance and record of any deviations, accompanied by certification of truth and accuracy of report signed by a competent person.

### 3.6 Pneumatic Pumps (Diaphragm Pumps)

3.6.1 Requirement for Control

A licensee or permit-holder of processing plants, gas downloading and compression stations, shall not use pneumatic pumps with natural gas venting. For pumps with cumulative deployment or in use for less than 90 days per year, these facilities shall be retrofitted with electric pumps or the emissions routed to a *Vapour Recovery System.*

3.6.2 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the proceeding year, stating level of compliance and record of any deviations, along with certification of the truth and accuracy of report signed by a competent person.

## 3.7 Centrifugal Compressor Seals

### 3.7.1 Control Requirements

A licensee or permit-holder is required to utilize *centrifugal compressors* with dry seals. Where compressors with wet seals are in place, a licensee or permit-holder is required to:

a. Route oil degassing unit emissions either to a *Vapor Recovery System* (including routing the emissions to the inlet of the compressor) or a combustion device.

b. Ensure the use of compressors with dry seals or retrofit existing compressors using dry seals within 180 days.

### 3.7.2 Monitoring

As part of instrumental LDAR, a licensee or permit-holder shall inspect compressors, wet seals, isolation valves, Vapor Recovery System or control devices, every 90 days.

### 3.7.3 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the preceding year, stating level of compliance and record of any deviations, along with certification of the truth and accuracy of report signed by a competent person.

## 3.8 Reciprocating Compressor Rod-Packing.

### 3.8.1 Requirements for Control

Emissions from compressor vents shall be routed using one of the following control options:

a. Replacement of rod packing on or before compressor has operated for 26,000 hours, or prior to 36 months from the date of the most recent replacement, whichever comes first. Within 36 months from the start-up date, the rod packing of a new reciprocating compressors shall be replaced.

b. Collection of methane and VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routes the emissions to a process through a closed vent system.

3.8.2 Monitoring

As part of instrumental LDAR, a licensee or permit-holder shall inspect compressor seals, rod-packing and Vapor Recovery Systems, every 90 days.

3.8.3 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the preceding year, stating level of compliance and record of any deviations, along with certification of the truth and accuracy of report signed by a competent person.

## 3.9 Glycol Dehydrators

3.9.1 Requirements for Control

a. A condenser or air pollution control equipment shall be used in the reduction of uncontrolled actual emission of hydrocarbon by at least 95% (on a continuous 12-month cycle) from *still vents* and vents from any flash tank on a glycol natural gas dehydrator located at natural gas compression station, or gas-processing plant. Where a combustion device is used, it shall have a design Destruction and Removal Efficiency of at least 98% for hydrocarbons.

b. Downtime of dehydrator due to maintenance or process upset, shall not be included in the calculation of 98% design Destruction and Removal Efficiency.

3.9.2 Monitoring

As part of instrumental LDAR, a licensee or permit-holder shall inspect Glycol dehydrator and Vapor Recovery System or control devices every 90 days.

3.9.3 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the preceding year stating level of compliance and record of any deviations, along with certification of the truth and accuracy of report signed by a competent person.

### 3.10 Liquid Storage Tanks: Flash Gas, Working & Breathing Losses

3.10.1 Requirement for Control

a. A licensee or permit-holder shall route emissions for all fixed roof storage tanks with potential to emit more than 2 tons per year (tpy) of Volatile Organic Compounds (VOC) due to flash gas, working losses, and breathing losses either to a Vapor Recovery System or to a combustion device, to be implemented as prescribed below:
   i. Within one year of implementation of these guidelines, tanks with VOC greater than 12 tpy shall be controlled.
   ii. Within 24 months of implementation of these guidelines, tanks with VOC 6 - 12 tpy shall be controlled
   iii. Within 36 months of implementation of these guidelines, tanks with VOC 2 -12 tpy shall be controlled.

b. A licensee or permit-holder of storage tanks for which the use of air pollution control equipment would not be technically feasible without supplemental fuel, may apply to the Authority for an exemption from the control requirements of Section 3.10.1(a) above. The request shall include details of the non-feasibility of the air pollution control equipment. This exemption shall not assuage a licensee or permit-holder of compliance with the storage tank monitoring requirements.

c. Venting of hydrocarbon emissions from hatches and other access points on tanks during normal operation is prohibited, except where:
   i. The hatch is opened for measurement purposes and closed immediately after the sample is taken.
   ii. An auto-gauging system or spigot to sample hydrocarbons in tank is used instead of opening the hatch.

d. A licensee or permit-holder of facilities with controlled tanks shall evaluate their systems for controlling tank emissions and certify that each system as designed is large enough to capture all potential emissions from the tank.

3.10.2 Monitoring

A licensee or permit-holder shall:

a. Conduct monthly AVO inspections of floating roof, fixed roof storage tanks and control devices to ensure emissions of more than 2 tpy are being routed to control units and flares and are operating as designed.

b. Monitor storage vessels, access points and Vapor Recovery Systems and combustors as part of instrumental LDAR.

c. Estimate annual methane emissions from the tanks and evaluate whether the exemption complies with conditions in Section 3.10.1(b) above. An

annual flash analysis testing for all tanks (with emissions >2tpy) that do not have Vapor Recovery Systems, shall be conducted.

3.10.3 Data Management

A licensee or permit-holder shall document monthly AVO inspections.

3.10.4 Reporting

A licensee or permit-holder shall submit an annual report not later than 90 days of the preceding year stating level of compliance and record of any deviations, along with certification of the truth and accuracy of report signed by a competent person.

# 4.0 INVENTORY

## 4.1 Inventory

4.1.1 A licensee or permit holder shall submit an inventory of all equipment that generates GHG as part of its GHG management plan.

4.1.2 The Authority may, however, require a licensee or permit holder of existing facilities to submit an inventory of all equipment that generate GHG separate from the GHG management plan within a specific timeline as determined by the Authority for accounting purposes.

## 4.2 Reporting

A licensee or permit holder shall report to the Authority every 90 days all measurements, estimations and quantification of GHG emissions from its operations. This shall cover Carbon Dioxide ($CO_2$), Methane ($CH_4$), Nitrous Oxide ($N_2O$) and all other Green House Gases associated with its operations.

4.2.1 The reporting requirements shall be for the following facilities:

a. Hydrocarbon processing facilities such as refineries, petrochemical plants, gas export terminals, blending plants, emulsion processing facilities etc.
b. Product depots and gas storage facilities
c. Industrial gas storage and utilization facilities
d. Waste management facilities.
e. Any other facility as may be determined by the Authority.

# 5.0 ACCOUNTING

## 5.1 General

In accordance with *Section 4.2*, a licensee or permit holder shall include the designated Base Year and corresponding baseline emission data, as outlined in the entity's GHG Management Plan.

## 5.2 Calculation and Estimation of emissions

A licensee or permit holder shall adopt the following approaches or a combination of any for calculating and estimating emissions:

5.2.1 Equipment Counts and Population Emissions Factor (EqC)

For a specific type of equipment emission, relevant emissions factors prescribed by the Intergovernmental Panel on Climate Change (IPCC) shall be employed for equipment counts, or any other methodology approved by the Authority.

5.2.2 Leak Surveys (LS)

Leak detection survey shall be conducted using equipment such as, Optical Gas Imaging (OGI) cameras, organic vapor or toxic vapor analysers, infrared laser beam, acoustic leak detection instruments and any other equipment as may be approved by the Authority.

5.2.3 Emissions Estimation and Quantification Requirements

**a. General Requirement**

ii. Operators shall adopt greenhouse gas (GHG) emissions estimation and quantification methodologies that are consistent with internationally recognized standards, including but not limited to the Intergovernmental Panel on Climate Change (IPCC) Guidelines for

National Greenhouse Gas Inventories, The GHG Protocol Corporate Accounting and Reporting Standard, The Oil and Gas Methane Partnership (OGMP) Framework, and Relevant ISO standards.

iii. All methodologies shall be subject to validation and approval by the Authority to ensure methodological consistency, transparency, and environmental integrity.

**b. Tiered and Level-Based Methodological Approach**

Operators shall apply a tiered approach to GHG emissions quantification, as defined by the relevant methodological standard:

i. The IPCC Tier system (Tiers 1, 2, and 3), where: Tier 1 represents basic estimation using default emission factors, Tier 2 uses country-specific or company-specific emission factors and improved activity data, Tier 3 involves advanced quantification through direct measurement, detailed modeling, or Continuous Emissions Monitoring Systems (CEMS).

ii. Where the OGMP applies, Level 1 to Level 5 methodologies may be used to reflect the maturity of emissions reporting and quantification practices. These levels are not interchangeable with IPCC Tiers but may be recognized as equivalent where applicable and approved by the Authority.

c. **Implementation Timeline**

i. Minimum Standard (Year 1): Within one (1) year of the effective date of these Guidelines, all Operators shall implement as applicable, at least Tier 1 methodologies, or OGMP Levels 1 or 2 where OGMP reporting is applicable.

ii. Enhanced Standard (After Year 1): From the second year onward, all Operators shall progress to higher-tier methods, such as Tier 2 or Tier 3, or OGMP Levels 3, 4, or 5, where applicable.

iii. The progression to higher-tier or higher-level methodologies shall be based on the materiality of the emissions source, availability of data and monitoring technologies, sector-specific best practices, and guidance from the Authority.

## 5.3 Regulatory Oversight

5.3.1 The data submitted shall be subject to quality control and validation by a multidisciplinary team made up of representatives from the Authority and the licensee or permit holder.

5.3.2 Where necessary, the Authority may appoint a third-party verifier to independently review and validate the submitted data.

5.3.3 The Authority may require licensees or permit holders already reporting GHG emissions prior to to the effective date of these Guidelines, to accelerate implementation schedules or apply higher-tier quantification methods where emissions are significant or not accurately reported.

## 5.4 Continuity of Reporting for Licensees and Permit Holders

5.4.1 A licensee or Permit holder who has been actively reporting GHG emissions prior to the effective date of these Guidelines and has already implemented Tier 1 (or equivalent) methodologies, shall continue to:

a. Maintain their current level of emissions quantification accuracy and data quality,

a. Maintain their current level of emissions quantification accuracy and data quality,
b. Progressively enhance their emissions estimation approaches by adopting higher-tier (Tier 2 or Tier 3) or higher-level methodologies (e.g. OGMP Levels 3, 4, or 5) as appropriate
c. Submit an updated GHG Management Plan to the Authority within six (6) months from the effective date of this Guideline, outlining timelines and strategy to fully comply with the enhanced standard requirements specified in Sections 2.2.2b and 5.
d. Ensure continued validation, transparency, and accuracy in their emissions reporting through periodic reviews and, where applicable, third-party verification.

5.4.2 The Authority may require alicensee or Permit holder who has been actively reporting to accelerate implementation schedules or adopt higher-tier quantification methodologies where significant emission sources are identified, based on audit findings and/or in alignment with regulatory priorities.

**Made in Abuja this** 4TH **day of** NOVEMBER **2025**

.....

**Engr. Farouk A. Ahmed**
Authority Chief Executive
Nigerian Midstream and Downstream Petroleum Regulatory Authority

# Appendix I: Technical Descriptions and Calculation

a. **Carbon Dioxide equivalent ($CO_2e(Kg)$) =** Mass of gas (kg) × Global Warming Potential (GWP)

Where: **$CO_2e$ (Kg)** = carbon dioxide equivalent in Kilograms.

**Mass of gas (kg)** = the actual mass of the greenhouse gas emitted (in Kilograms)

**GWP** = the 100year Global Warming Potential (GWP) for the relevant GHG generated from fossil sources based on the latest published IPCC Assessment Report.

b. **EPA Method 21**: This method is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

c. **EPA method 22**: This method is applicable for the visual determination of Fugitive emissions and also for the determination of the frequency of visible smoke emissions from flares.

d. **Estimation of Emissions Using Emission Factor**

- ***GHG Emissions ($KgCO_2e$)*** = *Activity Data(MT)* × *Emission Factor* × *Global Warming Potential (GWP)*

*(where applicable)* *(where applicable)*

**Where:** ***GHG Emissions (Kg $CO_2e$)*** = *Greenhouse Gas emissions in kilogram of $CO_2$ equivalent*

***Activity Data*** = *quantity of the activity causing emissions (e.g. litres of fuel burned, kWh of electricity consumed)*

***Emission Factor*** = *amount of GHGs emitted per unit of activity (e.g. kg $CO_2e$/liter, kg $CO_2e$/kWh)*

***GWP***= *100 year Global Warming Potential (GWP) for the relevant GHG generated from fossil sources based on the latest published IPCC Assessment Report.*

- ***Total GHG Emissions ($KgCO_2e$)*** = $\sum_i$ [***Activity Data$_i$(Kg)*** × ***Emission Factor$_i$*** × ***Global Warming Potential$_i$ (GWP)***]

*(where applicable)* *(where applicable)*

e. **GHG Intensity (Emission Intensity):**

GHG Intensity for a company is the sum of Midstream and/or Downstream petroleum preproduction and production GHG emissions during that year (in units of Kilogram (Kg) of carbon dioxide equivalents ($CO_2e$)), divided by the company's total production for that year in units of Barrels of oil equivalent (BOE).

It is calculated as:

$$\textit{GHG Intensity (Kg } CO_2e\textit{/BOE)} = \frac{\textit{Total annual GHG emissions (Kg } CO_2e\textit{/year)}}{\textit{Total annual Production (BOE/year)}}$$

*Where:* ***Total Annual GHG Emissions*** *is the Total GHG emissions in Kg* $CO_2e$ *for the year*

**BOE** = *Barrel of Oil Equivalent,*

f. **Verification of Optical Gas Imaging (OGI) Camera**

i. Verification shall be performed by either the licensee or permit-holder, manufacturer, or a third-party accredited by the Authority.

ii. Initial verification shall entail confirmation that the camera has the potential of imaging gases in the spectral range for the highest concentration compound in the potential fugitive emissions and

iii. The OGI camera shall have the potential of imaging a gas that is half methane, half propane at a concentration of less than or equal to10,000 ppm at a flow rate greater than or equal to 60g/hr from a quarter inch diameter orifice.

## Appendix II: List of Abbreviations

| | |
|---|---|
| **API** | American Petroleum Institute |
| **AVO** | Audio Visual and Olfactory |
| **DRE** | Destructive Removal Efficiency |
| **EPA** | Environmental Protection Agency |
| **GDP** | Gross Domestic Product |
| **GHG** | Greenhouse Gas |
| **HFC** | Hydrofluoro- Carbon |
| **IPCC** | Intergovernmental Panel on Climate Change |
| **ISO** | International Organisation for Standards |
| **LDAR** | Leak Detection and Repair |
| **NAP** | National Action Plan |
| **NDCs** | Nationally Determined Contributions |
| **NERGP** | Nigeria's Economic Recovery and Growth Plan |
| **OGI** | Optical Gas Imaging |
| **OGMP** | Oil And Gas Methane Partnership |
| **PPM** | Parts Per Million |
| **SLCP** | Short- Lived Climate Pollutant |
| **TAR** | Third Assessment Report (TAR) of the Intergovernmental Panel on Climate Change |
| **TPY** | Tonne Per Year |
| **UNFCCC** | United Nations Framework Convention on Climate Change |
| **VOC** | Volatile Organic Compound |

## Appendix III: Template for Reporting and Inventorisation of Green House Gas (GHG)

Various templates exist for reporting GHG. The most current versions of the IPCC reporting templates or any approved by the Authority, shall be utilised.

### Reporting Template Adapted from IPCCC

| Sector | Energy |
|---|---|
| Category | Oil and natural gas |
| Category code | 1.B.2 |
| Sheet | 1 or 2 (Oil and Natural Gas) |

| | | | | $CO_2$ | | $CH_4$ | | $N_2O$ | |
|---|---|---|---|---|---|---|---|---|---|
| IPCC Code | Sector Name | Subcategory | A Activity Data | B Emission Factor | C Emissions (Gg) | D Emission Factor | E Emissions (Gg) | F Emissions Factor | G Emissions (Gg) |
| | | | | | C=A*B | | E=A*D | | G=A*F |
| 1.B.2 | Oil and Natural Gas | | | | | | | | |
| 1.B.2.a | Oil | | | | | | | | |
| 1.B.2.a i | Venting | | | | | | | | |
| 1.B.2.A.ii | Flaring | | | | | | | | |
| 1.B.2.a.iii.3 | Transport | | | | | | | | |
| 1.B.2.a. iii 4 | Refining | | | | | | | | |
| 1.B.2.a.iii.5 | Distribution of Oil Products | | | | | | | | |
| 1.B.2.a.iii 5 | Other | | | | | | | | |
| | | | | TOTAL | | TOTAL | | TOTAL | |

| Sector | Energy |
|---|---|
| Category | Oil and natural gas |
| Category code | 1.B.2 |

| Sheet | | 1 or 2 (Oil and Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | $CO_2$ | | $CH_4$ | | $N_2O$ | |
| IPCC Code | Sector Name | Subcategory | A Activity Data | B Emission Factor | C Emissions (Gg) | D Emission Factor | E Emissions (Gg) | F Emissions Factor | G Emissions (Gg) |
| | | | | | C=A*B | | E=A*D | | G=A*F |
| 1.B.2.b | Natural Gas | | | | | | | | |
| 1.B.2.b.i | Venting | | | | | | | | |
| 1.B.2.b.ii | Flaring | | | | | | | | |
| 1.B.2.b.iii 3 | Processing | | | | | | | | |
| 1.B.2.b.iii 4 | Transmission and Storage | | | | | | | | |
| 1.B.2.b.iii 5 | Distribution | | | | | | | | |
| 1.B.2.b.vi | Gas post-Meter | | | | | | | | |
| 1.B.2.b.iii 6 | Other | | | | | | | | |
| | | | | TOTAL | | TOTAL | | TOTAL | |
| 1.B.3 | Other emissions from Energy Production | | | | | | | | |

******The most current versions of these templates shall be utilised.***

## Appendix IV- Definitions

a. ***Activity Data:*** Data on the magnitude of a human activity resulting in emissions or removals taking place during a given period. Data on energy use, metal production, land areas, management systems, lime and fertilizer use, and waste arisings are examples of activity data

b. ***Authority:*** The Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA)

c. ***Base year:*** The year in which the Regulated Parties carry out for the first time, in accordance with these Provisions, the quantification of GHG emissions in the hydrocarbons Sector Facilities, and which will serve as a reference to the emissions of subsequent years

d. ***Breathing Losses:*** Describes gas vapors that are released from an uncontrolled storage tank when the tank is subjected to a temperature rise, for example as a result of heat from the sun.

e. ***Centrifugal compressor:*** Equipment that increases the pressure of natural gas by centrifugal action through an impeller (Screw, sliding vane, and liquid ring compressors are not centrifugal compressors).

f. **Centrifugal compressor seal:** A wet or dry seal around the compressor shaft where the shaft exits the compressor case.

g. ***$CO_2$ equivalent ($CO_2$-eq) emission*** *means* the amount of carbon dioxide (CO2) emission that would cause the same integrated radiative forcing or temperature change, over a given time horizon, as an emitted amount of a greenhouse gas (GHG) or a mixture of GHGs. There are a number of ways to compute such equivalent emissions and choose appropriate time horizons. Most typically, the CO2-equivalent emission is obtained by multiplying the emission of a GHG by its global warming potential (GWP) for a 100-year time horizon. For a mix of GHGs, it is obtained by summing up the CO2-equivalent emissions of each gas. CO2-equivalent emission is a common scale for comparing emissions of different GHGs but does not imply equivalence of the corresponding climate change responses.

h. ***Competent Person:*** means one of the following:

i. *for a corporation*: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

ii. *for a partnership or sole proprietorship*: a general partner or the proprietor, respectively.

i. ***Compressor:*** A compressor is a mechanical device that increases the pressure of a gas by reducing its volume. It accomplishes this by transferring energy to gas, typically through mechanical work.

j. ***Compressor station:*** A compressor station is a facility which helps the movement of gas such natural gas, methane, ethylene, hydrogen, ammonia and carbon dioxide, from one location to another in a pipeline system.

k. ***Critical Component:*** Component that would require the shutdown of a critical process unit if the component was shut down or disabled.

l. ***Critical Process Unit:*** Process unit that shall remain in service because the shutdown of the unit could affect the safety and/or reliability of the natural gas supply system.

m. ***Emission Factor:*** *means a coefficient that quantifies the emissions or removals of a gas per unit activity. Emission factors are often based on a sample of measurement data, averaged to develop a representative rate of emission for a given activity level under a given set of operating conditions.*

n. ***Emission Intensity:*** An emission intensity (also carbon intensity or C.I.) is the emission rate of a given pollutant relative to the intensity of a specific activity, or an industrial production process; for example, grams of carbon dioxide released per megajoule of energy produced, or the ratio of greenhouse gas emissions produced to gross domestic product (GDP). Emission intensities are used to derive estimates of air pollutant or greenhouse gas emissions based on the amount of fuel combusted, the number of animals in animal husbandry, on industrial production levels, distances traveled or similar activity data.

o. ***Facility:*** Any building, structure, or installation to which these guidelines apply, and which has the potential to emit methane.

p. ***Facilities*** include all buildings, structures, or installations which:

   i. Are under the same ownership or operation, or which are owned or operated by entities which are under common control.

   ii. Are located on one or more contiguous or adjacent properties.

q. ***Fugitive Emissions (oil and natural gas systems)*** The intentional or unintentional release of greenhouse gases that occur during the exploration, processing and delivery of fossil fuels to the point of final use. This excludes greenhouse gas emissions from fuel combustion for the production of useful heat or power. It encompasses venting, flaring, and leaks.

r. ***Fugitive Emissions Component:*** Any component that has the potential to emit fugitive emissions of methane or Volatile Organic Compounds (VOC) including but not limited to a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum, valve, pipe, seal fluid system, diaphragm, hatch, thief hatch on a controlled storage vessel, sight-glass, meter, and open-ended line.

s. ***Green House Gases (GHG):*** Greenhouse gases are those gaseous constituents of the *atmosphere*, both natural and *anthropogenic*, that absorb and emit radiation at specific wavelengths within the spectrum of terrestrial radiation emitted by the Earth's surface, the atmosphere itself and by clouds. This property causes the greenhouse effect. Water vapor ($H_2O$), *carbon dioxide* ($CO_2$), *nitrous oxide* ($N_2O$), *methane* ($CH_4$) and ozone ($O_3$) are the primary GHGs in the Earth's atmosphere. There are a number of entirely human-made GHGs in the atmosphere, such as halocarbons and other chlorine- and bromine-containing substances, Sulphur hexafluoride ($SF_6$), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs).

t. ***Global Warming Potential (GWP):*** Defined as an index, describing the radiative characteristics of well mixed GHGs, that represents the combined effect of the differing times these gases remain in the atmosphere and their relative effectiveness in absorbing outgoing infrared radiation. This index approximates the time-integrated warming effect of a unit mass of a given greenhouse gas in today's atmosphere, relative to that of carbon dioxide ($CO_2$) *[TAR) of the IPCC]*

u. ***Leaks:*** Leaks are the unintentional releases of natural gas from equipment used in oil and gas operations. They are typically caused by mechanical (vibration) and thermal stresses, loss of tightness or wear of mechanical joints, seals, and rotating surfaces over time.

v. ***Leak Detection and Repair (LDAR):*** Operational best practice designed to identify equipment, including its components, from which leaks occur or may occur that need to be repaired in a given period in order to reduce and control emissions.

w. ***Level:*** This is the different levels of reporting as established by OGMP, used to quantify methane emissions. There are currently five (5) levels based on OGMP 2.0, with the following requirements:

i. Level 1- requires reporting of a single emission value for the entire company using generic emission factors

ii. Level 2- requires reporting by segment (Upstream, Midstream, Downstream) and emission type (Venting, Fugitive Losses, Flaring, Energy/Combustion).

iii. Level 3- requires companies to create a granular emission inventory based on equipment level information and generic emission factors.

iv. Level 4 requires operators to build on the equipment inventory by conducting measurements to update generic emission factors with measurement-based emission factors and

v. Level 5 requires companies to conduct top-down site-level measurements to reconcile with the bottom-up source-level emissions inventory created in Level 4. For the current version It consists of five reporting levels, with the highest level (Level 5) requiring that companies reconcile their source-level (Level 4) emission inventories with measurements at the site level.

x. ***Licensee:/ permit holder:*** Any entity, including an owner or contractor, having operational control of components or equipment, including leased, contracted, or rented components and equipment.

y. ***Lit Flare:*** adequate combustion: A flare with adequate combustion, operated with no visible emissions, except for periods not exceeding a total of 5 minutes during any consecutive hours.

z. ***Lit:*** poor combustion (sputtering, smoking, etc.): Is one that does not meet the requirements of:

i. Unlit flare with gas vent.

ii. Unlit flare with no gas vent

aa. ***Midstream and Downstream Gas Operations:*** means activities downstream of the measurement points of petroleum mining leases, whether or not related to the

petroleum mining lease, with respect to the construction and operation of natural gas transport or transmission pipelines, including the related compressor stations, construction and operations of facilities to compress, transport and deliver compressed natural gas (CNG); construction and operations of gas processing facilities and central processing facilities. producing ethane, propane, butane and natural gas liquids and marketable natural gas; construction and operation of underground or above ground facilities for the storage of natural gas, ethane extraction plants, construction and operation of gas to liquids (GTL) plants, construction and operation of lubricant, petrochemical and fertiliser plants, construction and operation of LNG plants, and related LNG terminals as well as storage and transport of LNG, acquisition. operation or chartering of LNG tankers for coastal and marine transportation, purchase and sale, trading, bartering, aggregating and marketing of natural gas transported by pipelines, compressed natural gas, LNG, methane, ethane, propane, butane, natural gas liquids and liquids from GTL plants with respect to wholesale customers and gas distributors and related administration and overhead.

bb. ***Midstream and Downstream Petroleum Liquids Operations:*** means activities downstream of the measurement points of petroleum mining leases, whether or not related to the petroleum mining lease, with respect to the construction and operation of facilities for upgrading of heavy oil, construction and operation of lubricant, petrochemical and fertiliser plants, construction and operation of petroleum liquids transport pipelines, including the related pumping stations; acquisition, operation, leasing, rental or chartering of barges, coastal or ocean-going tankers, railcars and trucks for the transport of petroleum liquids, construction, leasing and operation of tank farms and other storage facilities and export terminals for petroleum liquids, construction and operation of refineries, purchase and sale, trading, bailering, marketing of petroleum liquids and related administration and overhead

cc. ***Midstream and Downstream Petroleum Operations:*** means midstream petroleum liquids operations and midstream and downstream gas operations.

dd. ***Natural Gas Transmission Compressor Station:*** *A facility located downstream of natural* gas processing plant, which contains one or more compressors designed to compress natural gas to allow it to move through a transmission pipeline system.

ee. ***Natural Gas Processing Plant:*** Any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

ff. ***Petroleum Liquids:*** means crude oil, condensates, liquid petroleum products and natural gas liquids.

gg. ***Pneumatic pump:*** A device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.

hh. ***Reciprocating natural gas compressor:*** Equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.

ii. ***Reciprocating natural gas compressor rod packing:*** A seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that vents into the atmosphere.

jj. ***Reciprocating natural gas compressor seal*** means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.

kk. ***Seal***- A seal is a device or material used to prevent the leakage of fluids such as gases or liquids, between two adjacent components in a system.

ll. ***Tier:*** A tier represents a level of methodological complexity. Usually, three (3) tiers are provided. *Tier 1* is the basic method and uses activity data and default emission factors to estimate emissions from a particular industry segment or subsegment. *Tier 2* intermediate and *Tier 3* are sometimes referred to as higher tier methods and are generally considered to be more accurate. *Tier 2* estimates emissions at the industry segment or subsegment level but requires the use of country-specific emission factors, while *Tier 3* inventory requires detailed industry information and activity data that is used to estimate emissions.

mm. ***Validation***: Validation is the establishment of sound approach and foundation. In the context of emission inventories, validation involves checking to ensure that the inventory has been compiled correctly in line with reporting instructions and guidelines. It checks the internal consistency of the inventory. The legal use of validation is to give an official confirmation or approval of an act or product.

nn. ***Vapor Recovery System:*** Equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, and flow-inducing devices

used to collect and route emissions for processing, sales gas, or fuel gas system; or to an underground injection well.

oo. ***Verification***: Verification refers to the collection of activities and procedures that can be followed during the planning and development, or after completion of an inventory that can help to establish its reliability for the intended applications of that inventory. Typically, methods external to the inventory are used to check the truth of the inventory, including comparisons with estimates made by other bodies or with emission and uptake measurements determined from atmospheric concentrations or concentration gradients of these gases

pp. ***Walking Path***: a path that ensures that all fugitive emissions are within sight and account for interferences.

qq. ***Working losses***: Gas vapors that are released from an uncontrolled storage tank when the liquid level rises in the tank, pushing the vapors in the headspace above the liquid out of the tank.

## Appendix V: Sanctions

This guideline provides the minimum requirements for management of GHG and fugitive gas emissions. Non-compliance with the requirements shall be deemed as violations to relevant Laws, Regulations and subsequent amendments.

These violations may summarily lead to fines to operators or facility owner(s) or personnel and/or temporary or permanent revocation of License and/or permit and temporary or permanent withdrawal or non-approval of applicable permits and/or imposition of applicable penalties as prescribed in the relevant Regulations issued by the Authority.

The Authority Chief Executive shall from time to time cause a review of this document to reflect changes in international best practices, Government policies, Industry events or as may be deemed necessary.

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