UPSTREAM PETROLEUM ENVIRONMENTAL REGULATIONS 2022

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PART 1
PROJECT BASED ENVIRONMENTAL STUDIES

Environmental Risk Register (ERR)

1. An Environmental Risk Register is required to understand and collate all risks posed by the proposed project to the people and environment, and for the approval of the project.
2. A licensee/lessee and/or operator shall prepare an ERR for every development and/or upgrade modification of a facility such as:
    i. All Seismic Operations
    ii. Oil and Gas development activities
    iii. Development well drilling
    iv. Construction or modification of oil and gas production facilities, integrated upstream terminal facilities including Floating storage & offloading (FSO) and Floating Production Storage & Offloading (FPSO) vessels.
    v. Laying of crude oil and gas delivery lines, flowlines, and pipelines in cumulative excess of 20km length and/or as determined by the Commission.
    vi. Construction and/or Installation of Upstream Petroleum Waste Treatment and/or Disposal Facilities, viz: Wastewater Treatment Plant, Waste treatment/recycling /re-use facilities, Engineered Landfills.
    vii. Landfarming/ex-situ bioremediation in excess of 1.25km^2 of land take.
    viii. Dredging activities involving greater than or equal to 2,500m^3 of dredge spoils or 1,000m^2 of total area dredged.
    ix. Any other upstream petroleum activity / facility as may be determined by the Commission Chief Executive.
3. An ERR shall contain details of the concepts of the project, a list of the risks associated with the concepts, a qualitative description and quantitative ranking of the risk before and after risk elimination or reduction measures. Such measures shall be considered and approved by the Commission or rejected until an acceptable replacement is provided. Additional details on the content and procedure for preparing an ERR are contained in the UEGASPIN.
4. Verified data for risk description and analysis used in an ERR shall be obtained from the Commission at a cost where available or sourced by the project owner under the strict supervision of the Commission using an approved scope.
5. ERRs are kept valid as long as environmental monitoring and relevant statutory studies are conducted as applicable.

Mandatory Environmental Risk Register versus Project Interface

6. Except where project peculiarities demand further modification as may be determined by the Commission Chief Executive, the following sequence shall be the process for preparing an ERR for upstream petroleum development projects:

    i. Project Concept Screening (PCS) shall be carried out during concept selection studies. Every concept shall be environmentally screened, and the outcome of the screening shall influence the decision on the choice of concept. The Project Concept Screening report shall be approved and subsequently an approval for the concept will be granted by the Commission Chief Executive.
    ii. Preliminary Risk Assessment (PRA) report shall be prepared at the end of concept selection studies and issuance of a Field Development Plan (FDP), where applicable. The PRA shall focus on the selected project option and shall be prepared and approved before an approval for the project Front-End Engineering is given.
    iii. Draft Environmental Risk Register shall be prepared and submitted to the Commission Chief Executive during the Detailed Engineering Design and shall form the basis for the approval of the Detailed Engineering Design by the Director of Petroleum Resources.
    iv. Final Environmental Risk Register shall be prepared, with a detailed **Environmental Management Plan (EMP)** and an approval obtained at the end of the Detailed Engineering Design. The EMP shall form the environmental basis for project implementation. A pre-condition for the final approval of the ERR is the payment of a financial contribution to an Environmental Remediation Fund, in line with Section 103(1) of PIA 2021.

Environmental Evaluation Studies (EES)

7. A licensee/lessee and/or an Operator shall conduct an EES every Five (5) years from the date of commencement of operations in line with the Upstream Environmental Guidelines and Standards for the Petroleum Industry (UEGASPIN).
8. A licensee/lessee and/or an Operator that intends to divest any interests in its concession shall be required to conduct an EES to document the current state of the environment at the time of the divestment. The EES shall be supervised, and the report submitted for approval by Commission Chief Executive prior to finalising any divestment agreements.

Post Impact Assessment (PIA)

9. At the discretion of the CCE, a licensee/lessee and/or an Operator shall conduct a Post Impact Assessment following the clean-up after any incident such as oil or hazardous materials spillages, explosion/blow-out etc. has occurred, to ascertain the impact of the incident on the environment with a view to the restoration/remediation of same and for payment of

compensation where applicable. The PIA shall commence not more than 1 week from the date the clean-up is certified.

Environmental Baseline Study (EBS)

10. A licensee/lessee and/or operator shall conduct an EBS for onshore drilling of exploratory or appraisal wells of less than three (3) onshore exploratory or appraisal wells within any given 12- month duration. However, drilling of three (3) or more exploratory/appraisal wells within a 12-month period shall require an ERR.

Ecological Seabed Survey (ESS)

11. A licensee/lessee and/or operator shall conduct an ESS for the drilling of offshore exploratory or appraisal wells exploratory or appraisal wells less than three (3) offshore exploratory or appraisal wells within any given 12- month duration. However, drilling of three (3) or more exploratory/appraisal wells within a 12-month period shall require an ERR.

Biological Monitoring of Recipient Medium

12. An Operator shall institute a biological evaluation of effluent toxicity based on the bioassays which shall be conducted to determine the lethal and sublethal chronic toxicity effects of their treated effluents against approved species (based on the different trophic levels) in laboratory once every 3 months. Only effluents with demonstrated low risk of lethal and sublethal toxicity action against sensitive species shall be permitted for release into the recipient body of water.
13. An operator shall carry out biomonitoring of any recipient medium by conducting an ecological survey of pelagic and benthic flora and fauna to assess and record changes in biodiversity, abundance (population density), frequency of occurrence amongst biologically important species and bioconcentration of selected persistent effluent constituents in selected benthos along a 5 – 10 km radius and carrying capacity. Biomonitoring shall be carried out during wet and dry season, once every five (5) years.
14. Without prejudice to Section 12 and 13 above, and at the discretion of the CCE, a licensee/lessee and/or an Operator whose activities are presumed to have caused significant impacts, shall be required to conduct a biological monitoring of the recipient medium.

Special Studies

15. The Commission Chief Executive may direct a licensee/lessee and/or operator to conduct Special studies in response to new and emerging environmental challenges as may be deemed necessary.

Environmental Management Plan (EMP)

Requirement of an Environmental Management Plan

16. A licensee or lessee who engages in petroleum operations under the Petroleum Industry Act, 2021, shall submit for approval to the Commission an environmental management plan in respect of all projects. Details requirements and contents of the EMP are as provided in the Upstream Environmental Guidelines and Standards for the Petroleum Industry in Nigeria (UEGASPIN).
17. An environmental management plan must be in writing in a form approved by the Commission.
18. All ERR and EER reports shall contain functional chapters on EMP, with appropriate schedules of implementation.
19. The objective of the EMP shall be to demonstrate to the Commission that the operator has provided all required technology details of the project, the inherent risks and the means of reducing such risks to as low as reasonably practicable as detailed in the ERR and that the EMP is a documentation of the resources and procedures to manage the said risks as approved by the Commission.
20. The EMP shall:
    - Identify and discuss the management and/or implementation of commitments to stakeholders, as identified in the ERR;
    - Discuss how to implement the mitigating/amelioration measures, as identified in the ERR;
    - Design and implement an appropriate post-ERR monitoring and;
    - Identify the action party and provide time frame for implementation of issues identified.
    - Have a budget for implementation of mitigative measures and monitoring;
    - Put in place a systematic procedure of obtaining all necessary regulatory approvals for all the aspects of the project from start-up to de-commissioning.
21. A stand-alone EMP implementation action plan derived from the relevant sections of the ERR/EES report, shall be prepared and signed off by the top management of the project initiator and the Commission.
22. An environmental management plan submitted by a licensee or a lessee must be prepared by competent experts and must be accompanied by a statement from the licensee or the lessee outlining the relevant expertise or qualifications of such experts.

Contents Of Environmental Management Plan

23. The environmental management plan must include a description of the values and sensitivities of the project environment.
24. The environmental management plan must include environmental performance objectives that define the goals of the licensee or the lessee in relation to the —
    (i) processes, policies and practices to be followed; and
    (ii) equipment to be used; and
    (iii) actions to be taken,

    for the purposes of minimising the environmental impacts and environmental risks of the petroleum operations; and

Implementation strategy for environmental management plan

25. The environmental management plan must include an implementation strategy for the petroleum operations in accordance with this Regulation.
26. The implementation strategy must establish a clear chain of command, setting out the roles and responsibilities of personnel in relation to the implementation, management and review of the environmental management plan.
27. The implementation strategy must include measures to ensure that each employee or contractor working on, or in connection with, the petroleum operations is aware of his or her responsibilities in relation to the environmental management plan and has the appropriate competencies and training.
28. The implementation strategy must provide for the monitoring of, audit of, management of noncompliance with, and review of, the licensee's and the lessee's environmental performance and the implementation strategy.
29. The implementation strategy must include a spill prevention control and counter measures plan, and an oil spill contingency plan.

Approval Of Environmental Management Plan

30. Within [180] days after a licensee or lessee submits an environmental management plan, the Commission must —
    (a) approve the plan as stipulated under sections 33-37; or
    (b) refuse to approve the plan.
31. The above timeline applies to a resubmitted environment plan in accordance with the stipulated approval process in the same way that it applies to the plan when first submitted.
32. Where the Commission does not respond within the [180] day time limit the environmental management plan shall be deemed approved.
33. If the Commission is not reasonably satisfied that the environmental management plan when first submitted meets the stipulated approval criteria, the Commission must give the licensee or the lessee a reasonable opportunity to modify and resubmit the plan.

34. If, after the licensee or the lessee has had a reasonable opportunity to modify and resubmit the environmental management plan, the Commission is still not reasonably satisfied that the plan meets the stipulated approval criteria, the Commission must refuse to approve the plan.

35. Despite the rejection conditions stated in sections (33) and (34) above, the Commission may do one or more of the following:
    (a) approve the plan in part for a particular stage of the petroleum operations;
    (b) approve the plan subject to the imposition of limitations or conditions applying to the petroleum operations.

36. The Commission must give the licensee or the lessee written notice of a decision by the Commission —
    (a) to approve the plan; or
    (b) not to approve the plan; or
    (c) to do either or both of the following —
        (i) approve the plan in part for a particular stage of the petroleum operations;
        (ii) approve the plan subject to the imposition of limitations or conditions applying to the petroleum operations.

37. A notice under subsection (36)(b) or (c) above must set out —
    (a) the terms of the decision and the reasons for it; and
    (b) if limitations or conditions are to apply to the petroleum operations — those limitations or conditions.

Requirements for the Preparation of Environmental Studies Report

38. Environmental Studies reports for oil and gas industry projects shall be prepared only by competent persons or parties who possess the requisite accreditation/licence/permit.

PART 2 -
OIL FIELD WASTE MANAGEMENT

39. Oil Field Wastes shall not be discharged into the environment without the written approval of the CCE. Where required, such wastes shall be transported in fit-for-purpose containers/vessels as determined by the Commission.

Produced Formation Water Management

40. A licensee/lessee and/or operator is prohibited from carrying out operational discharges of Produced Formation Water (PFW) from upstream oil and gas facilities and installations into the zero-discharge zone without a written approval from the Commission Chief Executive.
41. The preferred disposal options for PFW shall be:
    a. Injection into approved disposal well(s)
    b. Re-injection into approved reservoir(s) or
    c. Other option(s) approved by the Commission Chief Executive for these purposes.
42. A licensee/lessee and/or operator may discharge PFW from its upstream oil and gas facilities/ installations only into Offshore Discharge Zones (ODZ) provided the stipulated conditions as provided in the UEGASPIN are satisfied.
43. A licensee/lessee and/or operator of a facility into which third party injectors send wet crude shall be responsible for the management of the PFW and shall share the associated liabilities with the third-party injectors.

Drilling Waste Management

44. A Licensee, Lessee or Operator shall not discharge whole drilling mud or fluids, spent drilling mud or fluids, brine, drill cuttings, well treatment wastes, deck drainage or residues thereof, from water and oil or synthetic based muds from drilling activities without a written approval of the Commission Chief Executive directly or indirectly into:
    a) Land, any inland waters or public drains and sewer.
    b) Swamp, Coastal, nearshore waters and offshore zero discharge zone
    c) Any pit on land/swamp other than approved temporary retention pit and/or steel tanks so designed and utilized that there shall be no overflow, leakage or seepage into the environment.
45. Discharge of whole water-based drilling mud or fluids, spent water-based drilling mud or fluids, brine, drill cuttings, well treatment wastes, deck drainage or residues thereof shall only be permitted in offshore areas, beyond the Zero Discharge Zone following treatment to limits that have been prescribed by the Commission.
46. Discharge rates and toxicity limits shall meet levels as prescribed by the Commission from time to time.
47. A licensee/lessee and/or operator shall reprocess or recondition spent oil-based drilling mud or fluid for further utilization. Spent oil-based drilling mud or fluid shall not be discharged on land and into inland, nearshore, offshore and deep offshore waters.
48. Technologies as may be approved by the Commission Chief Executive shall be used for treatment and disposal of drilling mud cuttings, sludges, and ash generated from the treatment process.
49. All drilling rigs shall be installed with efficient solids control equipment and be operated at all times to meet residual Oil-On-Cuttings limitations as prescribed by the Commission.

Other Operational Wastes Management

50. Hydrotest Water, pigging waste and any other effluent contaminated with production, drilling and completion chemicals from upstream operations shall not be discharged without written consent or approval from the CCE.
51. Solid wastes including but not limited to Produced sand, treated organic residues from primary oily wastewater treatment plant, spent catalyst, rust, ash, general refuse etc, off-spec product, oily sludges, shall be disposed of by methods approved by the Commission Chief Executive.
52. Sanitary wastes from upstream oil and gas facilities and upstream installations in nearshore and inland facilities shall be treated using Biological waste treatment system to satisfy discharge limitations prescribed by the Commission.
53. A Licensee, Lessee or Operator shall provide refuse containers for segregation of all waste streams and dispose of same in accordance with public health and sanitation procedures as well as procedures approved by the Commission Chief Executive.
54. Spent lubricants shall be differentially segregated from other oily effluents and channelled into a source recovery system where feasible or into a receptacle approved by the Commission Chief Executive. The treatment and disposal methods for the spent lubricants shall be approved by the Commission Chief Executive. These treatment and disposal methods shall include but not limited to recycling and incineration.
55. The Operators, ship owners, charterers and ship agents shall ensure that samples of clean ballast and treated bilge water to be disposed of shall meet effluent limitations for ocean ballast and disposal conditions as prescribed by the Commission before discharge in the offshore discharge zone.
56. All petroleum storage tanks, and vessel cleaning activities shall be conducted using only automated technology approved by the Commission Chief Executive. The tank cleaning activities shall be carried out only under the supervision of competent persons.
57. Gaseous emissions from Upstream oil and gas installations and facilities, comprising of but not limited to particulate matter, dust, methane, hydrocarbons, oxides of carbon, nitrogen and sulphur oxides, mercury, volatile organic carbons shall not be emitted directly into the atmosphere.
58. New Gas turbines shall be equipped with low NOx burners and existing facilities shall be retrofitted and the following conditions shall apply:
    a) Onshore and offshore regions less than 5km from the shoreline shall be equipped or retrofitted with low NOx burners.
    b) New facilities located between 5km – 25km from the shoreline to be equipped with improved conventional burners as may be determined by the Director of Petroleum Resources.
    c) All facilities located beyond 25km from the shoreline shall be installed with improved conventional burners as may be determined by the Director of Petroleum Resources.

59. Realtime Online monitoring and recording facilities shall be installed to determine all gaseous emissions compositions and concentrations which shall be reported to the Commission in a frequency as may be determined by the Commission.

Hazardous Waste Management

60. A Licensee, Lessee or Operator shall provide all information necessary and as required by the Commission, to identify hazardous materials and wastes used in or generated by its operations, which shall include but not limited to:
    a) Material Safety Data Sheet
    b) Waste Material Data Sheet
    c) Chemical Tests or Analysis on the Criteria and Characteristics of hazardous substances or wastes.
    d) Risk Assessment
61. The generator of such wastes shall be responsible for:
    a) A proper categorization, classification, description of wastes materials and a hazardous Waste Chemical Analysis Plan, that includes parameters to be tested, test methods, sampling methods and frequency of analysis;
    b) Risk Assessment.
    c) Waste minimization or reduction to the maximum extent practicable using the best practicable means;
    d) Site safety plan,
    e) Resource recovery where the hazardous waste is re-used or recycled for other useful purposes including uses as energy sources.
62. Generators of hazardous wastes shall ensure that:
    a. wastes generated are properly stored, treated on-site or transported to and received at permitted or licensed premises for treatment or disposal.
    b. Such off-site premises or facilities and mode of transportation shall satisfy the requirements of the Commission and other relevant Government Agencies.
    c. Such wastes shall not be stored, without treatment, for more than a period as may be determined by the Commission.
63. The Licensee, Lessee or Operator shall notify the Commission in writing within one month of the generation of hazardous wastes.

PART 3 –

POINT SOURCES

Point Source Registration

64. All new and existing industrial effluent discharge point sources at all Upstream facilities and installations shall be registered with the Commission. Licensees/Lessees/Operators shall obtain a permit issued by the Commission and sources shall be issued with permits, are renewable every five (5) years upon submission and approval of Environmental Evaluation Reports.
65. An Operator shall not be permitted to discharge any effluent or emission without a permit issued by the Commission, for all aspects of upstream petroleum related effluent discharges from gaseous, liquid and solid bearing point sources.
66. The fees for the Permit shall be as prescribed by this regulation.

PART 4 –

EMERGENCY RESPONSE AND POLLUTION ABATEMENT

Oil Spill Contingency Planning

67. An Operator shall submit its current Oil Spill Contingency Plan (OSCP) document the Commission within the first quarter of the year for review.
68. The OSCP shall be activated annually.
69. Each upstream Operator or upstream Facility Owner shall describe the areas of its operation. The operator is to identify beforehand, all sensitive areas that should be protected in the event of an emergency situation and provide other relevant information as may be determined by the Commission. An Environmental Sensitivity Index Map prepared to the standard provided by the Commission shall be required for the purpose.

Mystery Spills

70. An Operator, licensee or lessee shall be responsible for the containment and recovery of any spill discovered within its operational area, whether or not its source is known. The operator shall take prompt and adequate steps to contain, remove and dispose of the spill.
71. The cost so expended by the Operator, licensee or lessee in Section 71 above, shall be defrayed from the Environmental Remediation Fund.

Spill Reporting, Investigation and Clean-up

72. All spills of crude oil, chemical, oil products shall be reported to the Commission within 24 hours, in accordance with the Oil Spillage and Notification Reporting format prescribed by the Commission.

73. A Joint Spill Investigation team, comprising of the Licensee or Operator or lessee, Community, any third party responsible for the spill where known, the Commission and other relevant stakeholders shall be initiated by the Operator of the affected facility within 24 hours of spill notification to conduct a Joint Investigation Visit to the spill site as soon as practicable.
74. A licensee, lessee or operator responsible for a spill shall be required to conduct a Post Impact Assessment Study of any adversely impacted environment within a period of three (3) months of the spillage.
75. An approval by the Commission Chief Executive shall be required for any remediation and rehabilitation method to be used to clean-up and restore impacted site.

Liability & Documentation of Spills

76. A spiller shall be liable for the damage from a spill for which the Operator, licensee or lessee shall be responsible. Where more than one spiller is responsible and liable, the liability shall be joint and several.
77. The Operators or facility owners shall accurately record the history of the oil spill. A log of daily events shall be kept from the time a spill is first noticed until clean-up operations are completed.
78. A Licensee, lessee or operator shall keep a register of potentially polluted site or past impacted site. Such sites are to be cleaned up/remediated where applicable within 6 months and certified accordingly by the Director of Petroleum Resources.
79. The Licensee, lessee or operator of a facility shall submit to the Commission the cost of clean-up which shall include but not limited to the clean-up cost, down time man-hour loss, cost of man-hour utilization, the cost of materials and repairs and cost of unrecovered oil.
80. Every Operator, licensee or lessee shall conduct a geochemical characterisation (fingerprinting) of its crude oil from all its reservoirs with the supervisor of the Commission and submit the results.

Remediation and Restoration of Impacted Area

81. The approval of the Commission Chief Executive shall be sought first before the commencement of any remediation project.
82. The licensee, lessee or operator shall be responsible to restore as much as possible the impacted environment to its original state.
83. Any restorative process to be embarked upon shall adequately evaluate the biological sensitivities of the impacted environment. The post impact assessment study conducted shall determine the extent of damage and the estimated duration for complete recovery of such an environment.
84. A Licensee, lessee or Operator of a Facility responsible for a spill that results to impact of the environment shall monitor the impacted environment alongside the restorative activities as to be determined by the Commission.

Use of Oil Spill Chemicals and Remediation Products

85. All oil spill chemicals and remediation products intended for use within Nigeria and its territorial waters shall be subjected to relevant tests (microbial screening and/or terrestrial toxicity) prior to its approval by the Commission Chief Executive.
86. Any product containing exogenous microbes shall not be approved for used in remediation of any spill impacted sites in the Nigerian oil and gas industry.
87. The use of oil spill chemicals is prohibited in coastal and inland waters.
88. The On-Scene-Commander shall apply to the Commission for an authorization to deploy the oil spill chemical in offshore waters during a spill.

PART 5
EFFLUENT DISCHARGE STANDARDS, LIMITATIONS AND MONITORING

89. The Licensee, lessee or operator of an upstream petroleum facility that generates effluent waste streams shall ensure that such effluent streams conform with the standards, limitations and frequency of monitoring and reporting as prescribed by the Commission, before disposal.

PART 6 –
CONFLICT RESOLUTION

90. Settlement for damages and compensation arising from upstream petroleum environmental related issues, shall be determined by direct negotiation between an Operator and /or licensee, lessee, Landlord and relevant stakeholders, with the guidance of the Upstream Compensation Regulations.
91. Where direct negotiation fails, any of the following methods of settlement or a hybrid of these shall apply:
    a) Mediation by the Commission
    b) Arbitration at the Commission's Alternative Dispute and Resolution (ADR) Center or
    c) Litigation

PART 7 –
ABANDONMENT, DECOMMISSIONING AND DECONTAMINATION OF OIL AND GAS FACILITIES

92. The licensee, lessee or operator of an upstream facility shall plan for Decommissioning prior to project commencement and the details documented in the pre-project Environmental Study.
93. At the point of decommissioning, the licensee, lessee or operator shall provide an updated Decommissioning plan incorporating inventorization of idle irons, Naturally Occurring

Radioactive Materials survey report, Naturally Occurring Radioactive Materials decontamination plan, environmental remediation and restorative programmes, Environmental Evaluation study Report amongst others as may be determined by the Commission.

94. The operators, Licensee or Lessee shall appropriately decontaminate, dismantle and remove structures from upstream oil and gas installations and facilities after such installations and facilities have been abandoned and decommissioned in line with statutory provisions, approved guidelines and other requirements may be determined by the Commission.

95. Removal of Naturally Occurring Radioactive Materials containing scales and sludges from plant and equipment, during decommissioning, shall be conducted with adequate radiation protection measures and with due regard for other relevant safety, waste management and environmental considerations.

96. For facilities completely shut down and abandoned, decommissioning activities including physical removal of structures shall commence not later than one (1) year after abandonment and shall be completed within the stipulated period as approved by the Commission Chief Executive.

PART 8 –
Processing Fees, Fines and Penalties

Processing Fees

The following Processing fees shall apply

97. Engineered Landfill	**$USD**
a. Approval to Construct	(4,000.00)
b. Decommissioning Plan Approval	(3,000.00)
c. Permit to Operate	(4,000.00)
d. Point Source Registration per Facility	(2,000.00)
e. Revalidation of Operational Permit	(2,000.00)
f. Terms of Reference and Scope of Work	(2,000.00)
g. Project Concept Screening Report/Preliminary Impact Assessment Report	(2,000.00)
h. Final Environmental Risk Register	(2,000.00)
i. Draft Environmental Risk Register	(2,000.00)
j. Environmental Evaluation Studies or Post Impact Assessment	(2,000.00)
k. Approval to conduct Project activities in lieu of Completion of ERA	(25,000.00)

98. Laboratory	**$USD**
a. Laboratory Accreditation	(500.00)

b.	Re-Certification of Oilfield Chemicals/Remediation products	(500.00)
c.	Revalidation of Laboratory Accreditation	(250.00)
d.	Certification of Oilfield Chemical/Remediation products	(1,000.00)

99.	**Production**	**$USD**
a.	Consent for Produced Water Discharge	(25,000.00)
b.	Decommissioning Plan Approval	(5,000.00)
c.	Produced Water Re-Injection Permit	(5,000.00)
d.	Recipient Water Sampling Certificate per Quarter	(1,000.00)
e.	Terms of Reference and Scope of Work	(3,000.00)
f.	Project Concept Screening Report/Preliminary Impact Assessment Report	(3,000.00)
g.	Draft Environmental Risk Register	(4,000.00)
h.	Final Environmental Risk Register	(4,000.00)
i.	Biological Monitoring Studies	(3,000.00)
j.	Post Impact Assessment	(3,000.00)
k.	Post Clean-Up Certificate	(3,000.00)
l.	Revalidation of Effluent Waste Discharge Permit per Well	(1,500.00)
m.	Approval to conduct Project activities in lieu of Completion of ERA	(25,000.00)

100.	**Waste Management**	**$USD**
a.	Operational Permit per Facility	(750.00)
b.	Decommissioning Plan Approval	(5,000.00)
c.	Point Source Registration per Facility	(500.00)
d.	Revalidation of Operational Permit	(500.00)
e.	Terms of Reference and Scope of Work	(500.00)
f.	Project Concept Screening Report/Preliminary Impact Assessment Report	(500.00)
g.	Draft Environmental Risk Register	(500.00)
h.	Final Environmental Risk Register	(1,000.00)
i.	Environmental Evaluation Studies or Post Impact Assessment	(1,000.00)
j.	Approval to conduct Project activities in lieu of Completion of ERA	(25,000.00)

Fines & Penalties

101.	**General HSE Infraction**	**$USD**
a.	Use of non-accredited contractors to render any HSE related service in the oil and gas industry	(25,000.00)
b.	Failure to respond to Commission on HSE related issues within stipulated timelines	(25,000.00)
c.	Making false representation to the Commission on any HSE related issue	(100,000.00)

102.	**Environmental Permit**	**$USD**
a.	Drilling without obtaining Effluent Waste Discharge Permit	75,000.00/well
b.	Use of unapproved/unauthorized mud system in drilling operations.	10,000.00
c.	Discharge of cuttings contaminated with synthetic Oil based mud into offshore discharge zone without achieving less than 5%residual oil-on-cuttings.	1,000.00/bbl
d.	Discharge of cuttings contaminated with water/oil-based muds and /or esters in inland and nearshore areas.	1,500.00/bbl
e.	Discharging of cuttings contaminated with oil from Low Toxic Mineral Oil Based Mud System into offshore discharge zone without treating to a residual oil content of less than 10g/kg cuttings.	1,000.00/bbl
f.	Failure to conduct a Post Drilling ERA	15,000.00
g.	Failure to submit waste consignment note one month after drilling	10,0000.00/mth
h.	Use of unapproved waste management company	30,000.00
i.	Discharging of cuttings contaminated with oil from esters into offshore discharge zone without treating to a residual oil content of less than 100g/kg cuttings.	1,000.00/bbl
j.	Failure to register point source/revalidate permit for registered source.	(250)/point source/day

103.	**Environmental Studies**	**$USD**
a.	No Environmental Screening Study Report to determine Suitability of Project Concepts	25,000.00
b.	Altering Environmental Status prior to requisite Environmental Assessment Studies	50,000.00
c.	Commencing field data gathering without approved Scope of Work	25,000.00
d.	Commencing construction without final authorization	100,000.00
e.	Failure to conduct requisite study	150,000.00
f.	Failure to conduct Biological Monitoring Studies	50,000.00
g.	Delayed submission of Biological Monitoring report (more than six months after the final field data gathering	25,000.00

104.	**Waste Management**	**$USD**
a.	Noncompliance with submission of waste inventory notes	10,000/mth
b.	Dumping of waste	200,000.00
c.	Waste Transportation without the use of Commission approved systems	20,000.00
d.	Failure to conduct quarterly audit and inspection exercises	50,000.00
e.	Indiscriminate storage of waste within and outside operation areas.	50,000.00

f. Storage of waste in temporary retention pits for a period more than 3 months after the drilling activities.	50,000.00+ 20,000.00 for each additional month thereafter.
g. Operating under expired permit.	100,000.00
h. Discharge of Produced water in prohibited zones	1/bbl with a 10% annual increase if it persists.

105. Oil Spill Management	**$USD**
a. Failure to emplace adequate/reasonable measures to avoid spillages	100,000.00
b. Failure to effect agreed compensation	100,000.00
c. Failure to report a spill incident	100,000.00
d. Late reporting of spill incidents	10,000.00 + 1,000.00 for each day of late submission.
e. Making false or incomplete representations regarding the cause or volume of spills	100,000.00
f. Failure to convene a JIV with the Commission in participation	100,000.00
g. Failure to clean-up oil spill impacted site	100,000.00 + 10,000.00 for each additional month of non-clean-up
h. Failure to conduct post impact assessment	100,000.00
i. Use of certified oil spill chemicals (dispersants) without authorization	50,000.00
j. Use of non-certified oil spill chemicals (dispersants)	100,000.00
k. Failure to carry out crude finger printing on a field by field basis as statutorily required.	100,000.00

106. Laboratory Services	**$USD**
a. Use and sales of uncertified or unapproved oilfield chemicals	25,000.00
b. Failure to submit quarterly sales reports by Chemical Vendors, Operators (procurement, consumption & stock/balance) for Chemical regulations and tracking.	20,000.00
c. Operating a Laboratory without valid DPR accreditation	5,000.00

d. Falsification or alteration results by Laboratory	5,000.00
107. HSE Audit/OSCP Activation Exercise	**$USD**
a. Postponement of annual HSE Audit/OSCP Activation Exercise	50,000.00
b. Failure to facilitate the conduct of the annual HSE audit and OSCP Activation exercises	100,000.00
c. Failure to submit an updated OSCP document within the stipulated period.	100,000.00
d. Failure to close out identified audit issues within a stipulated time.	100,000.00
108. Remediation	**$USD**
a. Failure to adequately clean-up and remediate spill impacted sites	200,000.00
b. Failure to update the Commission on the numbers and status of oil impacted sites on request	100,000.00
c. False information on the number and status of oil impacted sites	100,000.00
d. Use of unapproved products and/or technologies for remediation.	10,000.00
e. Failure to obtain statutory certification for cleaned-up/remediated sites.	10,000.00

PART 9 –
PERMITS AND APPROVALS

109. A licensee, Lessee or Operator shall obtain from the following Permits and Approvals from the Commission:

a) An Environmental Permit for seismic activities before commencement of Seismic operations in Nigeria.

b) An Environmental Waste Discharge Permit for drilling / workover/ re-entry of any oil and gas well in Nigeria

c) An Environmental Permit to re-inject relevant waste generated from upstream Oil and Gas operations into approved disposal wells.

d) An approval to deploy any remediation technique or technology for restoration of sites impacted due to upstream oil and gas operations.

e) An approval to utilize any oil field chemical or product including but not limited to chemicals or products used for remediation, oil spill clean-up and control, drilling and production operations in the Nigerian Upstream Petroleum Industry.

f) A Permit to operate any waste management facility that will handle wastes generated from oil and gas operations in the Nigerian Upstream Petroleum Industry.

g) An approval for the management of secondary waste generated from the treatment of oil and gas wastes in the Nigerian Upstream Petroleum Industry.

h) A Waste Disposal Permit for the disposal of solid waste generated from oil and gas operations in the Nigerian Upstream Petroleum Industry from the Commission Chief Executive.

i) All other special environmental permits that may be determined by the Commission Chief Executive.

110. All service providers shall be required to undergo an accreditation process that will lead to the issuance of a permit.

111. Service providers that make use of facilities shall be required to undergo an accreditation of their facility and obtain an Operating Permit.

PART 10 –
ENVIRONMENTAL MANAGEMENT SYSTEMS

Establishment of Environmental Management system

112. A licensee, lessee or operator shall establish an Environmental Management System for its organisation which shall conform to statutory provisions, guidelines and directives as may be issued by the Commission.

Environmental Audits and Reviews

113. A Licensee, lessee or operator shall conduct environmental audits to facilitate management control of environmental practices and to assess compliance with the Environmental Management System and regulatory requirements.

114. A Licensee, lessee or operator shall regularly conduct environmental management reviews and verifications to evaluate the status and adequacy of its environmental policy, systems and procedures in relation to environmental issues, regulations and changing circumstances.

115. A Licensee, lessee or operator shall have an Environmental Performance Evaluation Management System in place and periodically report to the Commission in line with statutory provisions and guidelines.

PART 11 -
CLIMATE CHANGE

Green House Gas (GHG) Management

116. There shall be a mandatory monitoring, estimation of volume and reporting of Green House Gases (GHG) emissions from all oil and gas operations in the Nigerian Upstream Petroleum Industry. The Commission Chief Executive shall issue a Guideline for GHG inventory reporting and mitigation in line with international best practice.

Management of Methane Emission

117. The licensee or operator shall conduct monitoring and control of methane emission from new and existing facilities or projects in which the following activities are performed:
    a) The exploration and extraction of hydrocarbons and
    b) The treatment r~~efining~~ and storage of the extracted hydrocarbon
118. The licensee or operator must take inventory of equipment and components, identified as sources and possible sources of methane emissions and thereafter perform the Leak Detection and Repair (LDAR) programme in all the new and existing facilities as part of methane emission management.
119. 25(4) Operators and licensees shall develop and submit plan for decarbonization and net-zero targets in operations to the Commission.

PART 12 -

STATUTORY REPORTING

General Obligations

120. All licensee, lessee or operator shall periodically submit applicable reports in line with statutory provisions, Guidelines and requirements as may be determined by the Commission Chief Executive. within the timeframe stipulated.
121. All licensee, lessee and/or operator shall submit any information on their operations upon request by the Commission Chief Executive within the timeframe stipulated.

PART 13 –
LABORATORY OPERATIONS IN THE UPSTREAM PETROLEUM INDUSTRY

Accreditation

122. All laboratories (operator-owned in-house and third-party laboratories) in the upstream petroleum industry shall be subjected to accreditation by the Commission.

123. Only laboratory facilities approved/accredited by the Commission shall be used to conduct analytical services in the upstream petroleum industry in Nigeria. The Commission shall grant approval to an Owner and Operator of analytical laboratories to engage in analytical, investigatory, confirmatory and consultancy services in the upstream petroleum industry in Nigeria.
124. 29. All accredited laboratories, from time to time, shall be subjected to analytical performance evaluation by means of reference samples, proficiency testing programmes and inter-laboratory tests as determined by the Commission.

PART 14 –
OIL FIELD CHEMICAL CERTIFICATION

Certification of Oilfield Chemicals and Products

125. All oilfield chemicals and products intended for use in the Nigerian upstream petroleum Industry shall be screened to ascertain their hazard and risk potentials through Safety Data Sheet evaluation, relevant tests and any relevant investigation as may be prescribed by the Commission.
126. The satisfactory outcome of such tests/investigations shall determine the approvability or otherwise of such chemicals/products.

Toxicity Tests of Chemicals

127. Operators or Chemical vendors in the upstream petroleum industry shall be required to undertake toxicity tests of all low toxic base oil, oil-based mud systems, drilling fluids, chemical dispersants or any other oil field chemical on standard aquatic organisms under Nigerian environmental conditions.
128. The use of chemicals or products with exogenous microorganisms in the Nigerian Upstream Petroleum environment is prohibited.
129. Chemicals or products used for land clean-up or remediation of sites polluted with petroleum shall undergo terrestrial toxicity test with selected natural soil invertebrates or any other test (e.g., microbial screening) deemed necessary by the Commission.
130. The tests and investigations on oilfield chemicals or products shall be conducted by laboratory facilities approved by the Commission.
131. The procedure for the relevant test on chemicals under Nigerian environmental conditions shall be as approved by the Commission.
132. Operators shall seek the consent of the Commission and obtain an approval prior to deployment of any oil field chemical/product.

133. Operators shall submit to the Commission for approval their oilfield chemicals management programme for all new and existing facilities.
134. Operators/licensees and chemical vendors shall submit inventories of oilfield chemicals deployed in their operations. The frequency of the submission shall be as determined by the Commission.
135. The results of tests (e.g., bottles test) and other production chemistry investigations on use of oilfield chemicals shall be submitted to the Commission for review and at the discretion of the commission chief executive, such tests shall be witnessed by staff of the commission.

INTERPRETATION

In these Regulations:

'*Facility*' means The property containing the source of the chemical of concern where a release has occurred.

'*Facility Owner'* means the operator of a facility.

'*Emergency Response Plan'* means an organized and predetermined course of actions to be pursued in the event of an emergency (spill or leakage of oil, gas, chemicals/hazardous substances, fire, man overboard, loss of containment, natural disaster, injury, piracy, security breach e.t.c). This orderly arrangement of events to effectively manage the incident shall be compiled in a document by all operators. In this context, anywhere oil is mentioned in the regulations, it shall be deemed to also mean gas, chemicals and hazardous substances where applicable.

'*Spiller*' means the operator of a facility from which hydrocarbon was released into the environment.

'*Product(s) containing exogenous microbes*' means any substance or chemical that is intended for use in the Nigerian oil and gas industry for remediation of hydrocarbon impacted sites whose origin is foreign and contains microbes.

Special studies refer to studies that are initiated based on the need to solve peculiar environmental challenge such as fate and effect studies, dispersion modelling and environmental risk assessment.

'NOx' means oxides of nitrogen

'LPG' means Liquified Petroleum Gas

‘*CNG*’ means Compressed Natural Gas

‘*LNG*’ means Liquified Natural Gas

‘*GTL*’ means Gas to Liquid

‘*Mth*’ means month

Chemical Vendors are entities, companies, organization licenced by the Director of Petroleum Resources to sell chemical utilized for any process in the oil and gas value chain.

On Scene Commander is the person responsible for coordinating (organizing and directing) all actions and parties during an emergency response situation

Licensee means the Oil Prospecting holder

Lessee means Oil Mining Lease holder

Operator means an Operator as defined by either a PSC, JOA, TSA and any other contractual agreement. Operator can also be the OPL or OML Holder.

All Processing Fees, Fines and Penalties covered in this document can also be paid in ‘naira’ value using the prevailing Central Bank of Nigeria (CBN) rate.

A **Waste Generator** is a licensee/operator of an oil and gas production facility or oil and gas servicing facility who during its activities/operations, **generates** a waste stream(s) e.g. water, gas, sand/soil, oil, solids (hazardous and non-hazardous) etc.