in association with

NIGERIA EXTRACTIVE INDUSTRIES TRANSPARENCY INITIATIVE

REPORT ON THE PHYSICAL AUDIT 1999-2004

Presented to

The National Stakeholder Working Group

by

Hart Resources Ltd

in association with

SS Afemikhe Consulting Ltd

and

CMA Ltd

Final Submission

November 2006

Information as at 30th June

The report and all appendices relating to the report are intended for the use of the National Stakeholder Working Group of the NEITI for the purpose of that initiative and are not to be relied upon by other parties.

CONTENTS

APPENDICES

PREFACE

This is the final report under The Nigeria Extractive Industries Transparency Initiative (NEITI) Physical audit.

In April 2006, an earlier version of this report was presented; the present report reflects the findings of certain further work undertaken in the period May – August 2006.

This report is intended for the use of the National Stakeholder Working Group of the NEITI for the purpose of that initiative and is not to be relied upon by other parties.

The report comprises this volume and appendices which are bound separately.

The report reflects data and information received by Hart Group from covered entities up to 30th June 2006, which was the cut-off date specified by NSWG. Comments and adjustments received after that date have been taken into account where feasible but not all could be accommodated.

1 EXECUTIVE SUMMARY

Hydrocarbon volume mass balances have been developed by companies and presented to us. Companies did not routinely prepare such information during 1999-2004, although this began to change more recently. All companies have presented net volume balances, but not all have presented gross liquid balances (including water and losses) and the reliability of these balances in doubt. Consequently, this data is inherently not suitable to derive the amount of unaccounted oil.

The aggregation of information provided in this report may be misleading because of the varying bases on which companies have presented their data. The constraint is the manner in which data is collected and retained. To arrive at the upstream countrywide hydrocarbon balance, it has been necessary to aggregate net balances with gross balances, which gives a misleading view of the relationships between the figures.

Export volumes have been agreed between DPR and the companies and NNPC, following an extensive exercise requiring several iterations between the parties.

The audit has materially verified the volumes of crude exported by NNPC. These volumes lifted by NNPC, which have been derived from the physical reconciliation of flows, are however, slightly different from sales volumes recorded by COMD.

Volumes used by the companies for Royalty and PPT show significant differences, between the reconciled hydrocarbon flows and the taxation and royalty returns. The position, however, is very complex due to the arrangements for unitisation and product swaps between companies. We are currently in the process of discussing with companies how they prepared their figures.

We recommend that reconciliation of export liftings between DPR and companies should take place regularly in order to identify inconsistencies in the records and adjust them on a timely basis. The conduct of the physical audit indicated shortcomings in both DPR and company record keeping that were hard to resolve after the passage of time.

DPR has not taken a lead in setting and enforcing measurement standards. DPR was not able to provide us with procedures and guidelines to be used in measuring crude and liquid flows throughout the system, with the exception of a “Manual of Procedure Guides for the Petroleum Inspectorate”, which is not comprehensive in this respect. There seems to be no process for keeping procedures up to date and in line with international best practice. Arrangements for monitoring the entire hydrocarbon balance of the sector, from wellhead to terminal / refinery should be reinforced. We recommend that DPR should spearhead this. Guidelines / Standards should be established for preparation of formal mass balance statements.

The metering infrastructure and the records do not allow the hydrocarbon balance to address the question of unaccounted oil. As NSWG wishes to obtain information on this issue for the future, a suitable information system mainstreamed into the companies’ information and reporting systems, needs to be established to provide the data, without resorting to ad hoc exercises. We recommend that a dialogue be opened involving NSWG, DPR, NAPIMS and the companies (OPTS might facilitate this) to agree how to proceed. There may be expenditure implications for JVs if additional metering points are required. There is a range of issues on definitions and practices to be applied in arriving at the reported mass balance. These, and the timing of implementation, should be agreed on an industry-wide basis.

Each company should prepare an annual statement for submission to DPR AND FIRS setting out the reconciliation of its PPT and Royalty self-assessments to the annual mass balance.

Annual audited cost reports submitted to NAPIMS should include the mass balance, prepared in accordance with relevant standards.

Responsibility for regulation of gas should be defined. Heavy regulation is not required but the present system suffers from lack of regulation.

2 INTRODUCTION AND SCOPE OF REPORT

2.1 Introduction

This is the final report (updated to 30th June 2006) of the Nigeria Extractive Industries Transparency Initiative Physical Audit.

The complete scope of the Physical audit encompasses the mapping of hydrocarbon flows, the assessment of the quality of procedural systems, the technical assessment of measuring hydrocarbon streams, the volumetric analysis and reconciliation of data both physical and financial, recommendations for improvements and reporting templates, and the aggregate reporting of hydrocarbons produced and fiscalised in the audit period 1999-2004.

The hydrocarbon flows include the following systems (see graphic in Section 3):

- crude oil recovery from oilfield wells, onshore and offshore, to terminal outputs (for refineries and export).
- the supply of crude oil from terminals to the refineries.
- gas recovery from oilfield and gas wells, onshore and offshore, to gas processing plants, the transmission of gas to NGC's pipeline system to inland customers and to NLNG for export of liquefied natural gas.
- the supply of petroleum products, from the domestic refineries and imports into Nigeria, into and through the inland product distribution system.

The downstream crude supply to refineries and product import have been included in the Physical & Process Downstream report (refining and product importation).

The elements of mapping, metering, volumetric analysis and recommendations constitute an integral whole for each of these systems. This final report is therefore structured in order to bring together these elements for each of the systems.

This report is intended for the use of the National Stakeholder Working Group (NSWG) of the NEITI for the purpose of that initiative and is not to be relied upon by other parties.

2.2 Objectives

The purpose of the report is to present:

- The diagrammatic mapping of hydrocarbon flows in Nigeria, including: production, exports, imports and inland consumption. These flows include crude oil, petroleum products, natural gas and liquefied natural gas (LNG).
- The assessment of the quality of technical facilities of measuring relevant hydrocarbon streams.

- The annual reconciliation of:
    i) individual shareholders' equity stake in the hydrocarbon streams
    ii) the amount of oil and gas produced with that used for calculating petroleum profit tax (PPT) and royalty payments

iii) the amount of oil and gas used for PPT purposes as per operating companies records with those as per FIRS records.

- Recommendations*:*
  i) improvements to future reconciliation exercises
  ii) to improve the future protection of FGN's interest in the hydrocarbon volumes and duty

  and an estimate of the incremental benefits to the FGN if the recommendations are implemented.
- Reporting templates and models that permit the FGN and Nigerian civil society to effectively assess the size and nature of Nigeria's hydrocarbon production, consumption, import and export volumes.
- The report aggregating Nigeria's hydrocarbon volumes produced and fiscalised, including discrepancies, during the period 1999-2004.

2.3 Layout of this Report

This report is structured to address these objectives for each of the hydrocarbon systems. Following a schematic and descriptive overview of the hydrocarbon system as a whole, there are four separate sections dealing in turn with: the Crude Oil system (section 4), the Gas system (section 5), the Refinery Supply system (section 6), and the Products Supply system (section 7).

Data on individual entities is included in the Appendices.

2.4 Physical Audit Procedure

In April 2005, requests for information on oil production and export volumes were issued to all companies who produced oil or gas during the period 1999-2004. These requests included templates on which the data was to be reported. Similar templates were issued to DPR requesting details of export volumes they had registered for the various producing companies. This was to enable the data from both sources to be verified. The companies were also asked to provide details of their pipeline networks showing the Flow Stations and metering points connected to it, plus any connections with another company's pipeline network.

DPR returned their completed templates promptly in August 2005. The supply of data from the producing companies however was delayed for many months. The auditors started receiving completed templates from the companies in late November 2005, the final ones arriving only late in March 2006. Information was eventually supplied to the NEITI audit team by fifteen operators, as shown in the table at the end of this section.

The initial reconciliation between the export data supplied by DPR and the various Oil companies revealed several non-conformities for all companies. These initial tabulations were sent to the various companies during late January and early February 2006, along with a list of questions highlighting the situation. From 27th January to 3rd February, individual meetings with the major producers took place to obtain answers to these discrepancies and the questions raised. All companies subsequently held meetings with DPR to resolve the differences and the amended data from all sources was finally received in March 2006 and is incorporated in the "net oil mass balances" shown in this report.

The data initially supplied by the Oil companies for the Flow Station production rates all gave net volumes. These had been calculated based upon the fiscal volumes measured

at the custody transfer point, commonly the Export Terminal. The tabulations using this data are clearly showing all reconciled export volumes, plus capturing the net oil volumes attributed to each Flow Station. What the data was not doing however is reveal any unaccounted losses in the pipeline system between the liquids leaving the Flow Stations and arriving at the Terminals. This was considered unacceptable by the audit team and was discussed individually with the producers. It was also stressed at a meeting on 8th February 2006 attended by representatives from COMD, DPR, FIRS, NNPC and the NSWG Secretariat, as well as personnel from eleven Oil Companies. All parties agreed to supply the data for this overall "Gross Liquids Mass Balance" by 17th February. Regrettably not all operators have supplied such information.

At the meeting of 8th February 2006, the producing companies were also asked to provide the annual volumes of oil, gas & water produced by each of their wells for the 6 years under review. The delivery of this data was agreed with a deadline of 8th March. The companies also agreed to provide by 17th February the monthly exportable volumes used for Royalty purposes. The supply of separate tables listing exportable volumes, plus the well data, was not good.

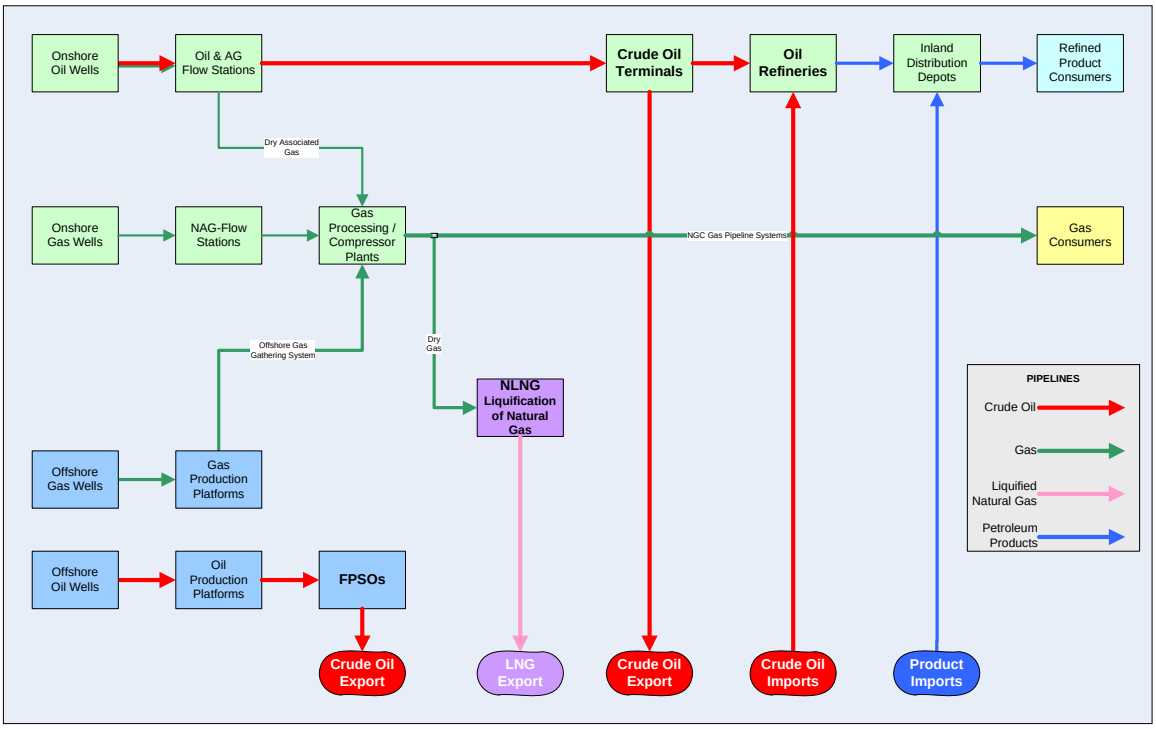
Due to ongoing difficulties, the President met the companies on 18th February. Progress in providing data was discussed. An extended deadline of 14th March was agreed by which all data should be provided. This deadline was met by most entities. However, the quality of the data received was variable. A reconciliation and data cleaning exercise was required in order to agree final terminal exports and mass balance data. Our report in April 2006 was based on the outcome of this exercise, which had eliminated most of the differences.

The President asked for all differences to be resolved and further work was carried out by the companies and NNPC, culminating in a three-day plenary meeting of all producing entities. This was convened by DPR and attended by ourselves, NNPC and all the companies. As a result, DPR has agreed with every producer the volume of crude oil exported during each year from 1999 – 2004 and the volume of crude oil supplied from the oil terminals to the refineries during that period.

3 OVERVIEW OF HYDROCARBON SYSTEM

3.1 Schematic Overview

The hydrocarbon systems in Nigeria are shown thus:



Detailed schematics for each system are included in the sections below and in the Appendices of this report.

3.2 Descriptive Overview

3.2.1 Hydrocarbon Flows

Upstream Oil

The hydrocarbons in Nigeria are produced from oil and gas wells all over the Niger delta, both on land, in the swamp and offshore, in shallow and deep waters. Each onshore and shallow offshore well is connected by a flow-line to a Flow Station. Offshore wells further from land are connected to Production Platforms. At the Flow Station or Production Platform the liquids are separated from the gas.

New areas are being developed further offshore in very deep water, typically 1000 meters deep, but there was no production from this area in the period under review.

From onshore and shallow offshore wells the liquids, usually a mixture of oil and water, are then pumped through a pipeline to an Oil Terminal where the water is removed. The oil is stored in tanks before being pumped through fiscal meters to supply the refineries or into an Oil Tanker for export.

Offshore the well fluids are pumped from the Production Platform to a Floating Production Storage and Offloading vessel (FPSO). These are tankers permanently moored that process the liquids in addition to storing the crude oil ready to be exported.

Upstream and Downstream Gas

Gas can occur either associated with the oil (Associated Gas, AG) or as non-associated gas (NAG) with no or low amounts of oil present. Usually some of the gas is used as fuel to operate the Flow Station and, in some fields, gas is re-injected into a reservoir to maintain pressure and improve oil recovery.

Associated gas (AG) is mainly used to supply NGC, the Nigerian Gas Company. This is piped directly to NGC if the pressure is high enough, or via compressors if necessary. Associated Gas is also used to produce LPG such as Propane and Butane, and to supply NLNG. Non-associated gas (NAG) is the main feed into Nigerian Liquefied Natural Gas, NLNG's plant at Bonny. Condensate is the name given to the clear oil produced from gas wells; where this is found it is piped to a terminal, stored and exported separately from crude oil.

Any gas not used in these ways is presently flared. Significant steps have been taken to reduce the quantity of gas flared and a zero flare policy is scheduled for 2008.

NGC owns and operates the majority of the gas transmission network: NGC buys gas from the producers and sell the gas on to large process users and resellers. Large process users such as NEPA (PHCN) buy the gas from either NGC or directly from the producers. Smaller users buy the gas from resellers.

NLNG, Nigeria Liquefied Natural Gas Limited, buys gas from three joint venture (JV) operators (SPDC, NAOC, EPNL) and produces Liquefied Natural Gas (LNG) for export.

Crude Oil Supply to the Refineries

From onshore and shallow offshore wells the liquids are pumped through pipelines to the Oil Terminals. Some of the "dry" oil is pumped through fiscal meters to the Refineries where it is refined into products such as petrol and diesel. Small amounts of 'sour' crude oils are imported for use in the Kaduna refinery for "lube oil" production; the Nigerian crude is classified as 'sweet'.

Products Supply

Petroleum products from Nigeria's refineries at Port Harcourt, Warri and Kaduna together with imported products are distributed through PPMC's pipeline network to depots where the products are transported by road tankers to the marketers' outlets.

4 CRUDE OIL SYSTEM

4.1 System Overview

The main elements of the crude oil system are:

- Shell to Bonny, supply to PH refinery and export
- Shell to Forcados, supply to Warri and Kaduna refineries, and export
- Chevron to Escravos, supply to Warri and Kaduna refineries, and export
- Agip to Brass and export
- Texaco to Oloibiri and export
- Mobil to Qua Iboe and export
- FPSOs: Falcon/Yoho, Unity/Odudu, Ailsa Craig/Ima, Gray Warrior/Abo, Mystras/Okono, Knock Taggart/Antan,

The format of the pipeline network information provided by the producing companies varies considerably. In order to promote a clearer understanding of the facilities, a standardised presentation of these pipeline networks has been prepared for the companies who have responded; these are shown in Appendix A.

4.2 System Description

The main elements of the oil hydrocarbon production system are as follows:

1) Reservoirs

The reservoirs in Nigeria are sedimentary, the various sediments carried by the Niger River over the millennia have been deposited and it is in the rocks thus formed that oil and gas are found.

2) Wells

The reservoirs in Nigeria are very deep underground, commonly 6,000 to 12,000 feet below ground level, which is more than one to two miles deep. To recover these hydrocarbons a hole is drilled into the reservoir and pipes installed to enable the reservoir contents to flow to the surface. This is called the well. As a well gets older the production rate decreases and frequently the water content increases significantly, this may require intervention to improve production rates. In Nigeria a well will often penetrate several separate reservoirs which are produced one at a time. When the production from one reservoir declines to unacceptable levels that reservoir is isolated and another reservoir opened up for production.

3) Well Fluids

A hydrocarbon reservoir normally contains gas, oil and water. If it contains mostly gas it is referred to as a gas reservoir and is normally only produced when there is a specific need for the gas, such as to supply NLNG. An oil well of course, produces mainly oil. The fluids flowing from wells are normally a mixture of oil, gas and water. The water content of the liquid is given as a percentage BS&W (Base Sediment & Water); the base sediment includes the traces of sand etc. commonly produced with the fluids. Crude oil can vary widely in its properties, it can be black and very thick and viscous, or it can be clear and look and pour like water, and all stages in between. Condensate is the name given to the clear oil produced from gas wells. The gravity of oil is reported in degrees API, which is an International Standard established by the American Petroleum Institute.

4) Flow-lines

Flow-lines are steel pipes through which the hydrocarbons flow from the well to the Flow Station. Flow-lines are typically 4-6 inches in diameter and from a few hundred metres up to 5 miles in length.

5) Flow Stations and Production Platforms

At Flow Stations, the fluids from up to twenty wells are gathered together for treatment to separate the liquids from the gas. Approximately once a month each well is routed through a special vessel to measure the production rates of the oil, gas and water. The liquid mixture of oil and water is then pumped from the Flow Station through trunk lines to an Oil Terminal. Occasionally some of the water is separated from the oil at the Flow Station and disposed of locally. Offshore Production Platforms carry out much the same activity as Flow Stations onshore.

6) Pipelines

Pipelines are large steel pipes through which hydrocarbons are pumped from Flow Stations to Oil Terminals. When several pipelines reach the same place in the field, they are connected together at a manifold and the flows combined to flow through a single but larger pipe. The size of the pipe depends on the volumes to be transported; they are commonly in sizes from eight inches diameter up to 36 inches or larger in diameter.

7) Oil Terminals:

At an oil terminal the oil and water is separated. The “dry” oil is stored in tanks ready to be loaded into Ocean-going tankers for export. Contractually the maximum water content allowed in oil to be exported is 0.5%. Land based Oil Terminals are on the coast to facilitate the access of the Very Large Crude Carriers (VLCC’s) needed to load the big volumes produced in Nigeria. If the oil field is offshore, typically the oil is transferred by flow lines and stored in a permanently moored tanker, a Floating Storage & Offloading facility (FSO or FPSO- floating production, storage and offloading). In all cases the oil to be exported is pumped through highly accurate meters into the export tankers. This “fiscalisation” activity is closely monitored by both the Oil Company concerned and DPR (Department of Petroleum Resources) on behalf of the Federal Government of Nigerian. The water from which the oil has been removed is disposed of locally.

At the end of 2004 there were the following 15 oil export terminals in Nigeria.

OPERATOR	LOCATION	Offshore vessel
Agip	Brass	(onshore)
Chevron	Escravos	(onshore)
ChevronTexaco	Oloibiri	(onshore)
Mobil	Qua Iboe	(onshore)
Shell	Bonny	(onshore)
Shell	Forcados	(onshore)
Addax	Antan	Knock Taggart
Amni	Ima	Ailsa Craig
Express/Conoco	Ukpokiti	Independence/ Spirit
Mobil	Yoho	Falcon
NAE	Abo	Gray Warrior
NPDC/AENR	Okono	Mystras
Shell	Ea	Sea Eagle
Total/Elf	Odudu	Unity

All these exports points have their own fiscalised metering systems.

See Appendix A for detailed schematics and geographic map including terminals.

8) Metering & Fiscalisation

The accuracy required from hydrocarbon measurements depends on what it is being used for. The higher the accuracy needed, the higher the cost and maintenance requirements.

Measurements in the Flow Stations etc. are less accurate because they are used for field control reasons only.

The highest accuracy is for fiscal purposes; where the custody of the product changes hands and the recipient pays the provider. Fiscalisation takes place at Terminals to measure exports; transfers to refineries and other customers, plus “third party” transfers into a pipeline network belonging to someone else. Metering to fiscal standards is normally +/- 0.25% for liquids and +/- 1% for gas. Field measurements are typically +/- 10%.

9) Contractual arrangements for development, production and sale

In Nigeria there are two commonly used types of contracts, a JV or Joint Venture, and a PSC, a Production Sharing Contract.

Joint Venture (JV): the development of an acreage block is awarded to a joint venture between NNPC and an Oil Company. All Exploration and Production costs are shared, the Oil Company pays Royalties, Petroleum Profit Tax (PPT), and for gas pays company income tax on profits.

Production Sharing Contract (PSC): NNPC owns the acreage and awards a contract to a company to carry out petroleum operations on behalf of NNPC. The contractor provides all necessary finance and bears all related risks; the operating costs are recovered from production. The contractor has a share of the profit oil and pays Royalties and tax. NNPC is not a risk-sharing partner.

In addition to these two types of contracts, the following contractual arrangements also exist for oil and gas production:

Unitisation: where a field overlaps the boundaries of a license area, the licensees on each side of the boundary enter into an agreement between them as to the sharing of the resources in the field and which of them will produce from the field.

Carry agreement: this is a form of alternative financing. It is akin to a joint venture except that financing is not shared equally between the partners. One party (usually NNPC) will be ‘carried’ in the sense that their share of financing costs is borne by the operator. The operator recovers the financing costs through production.

10) Tankers

The party responsible for the sale of that oil arranges the oil tankers used to export the oil. This responsibility depends on the contract the producing company has with FGN as mentioned above.

11) Third Party Oil

Some oil fields have oil volumes too small to justify having pipelines to their own Terminals. In this case the gathering network belonging to a nearby major producer is used. This occurs when it is not cost effective for a company to connect an isolated oil field to their own pipeline network, or when the field belongs to a smaller independent producer. At the point of custody transfer, it is through accurate meters, the regular calibration of which is witnessed by the producer, the receiving company and DPR.

5 HYDROCARBON VOLUMETRIC RECONCILIATION

5.1 Introduction

Details of oil production figures were requested from all of the oil producing companies in Nigeria, in order to establish the volumetric aspects of production, exports, unaccounted oil and other relevant streams, for the period 1999-2004. Additionally, the information was designed to demonstrate that the proper revenues due to FGN had been paid, based on the correct volumes.

Information was supplied by fifteen operators. The only company which did not supply data was Cavendish, which stated instead that it had suspended production prior to 1999.

5.2 Hydrocarbon Mass Balance

We first describe the net oil mass balance, adopted by companies in reporting their monthly report of producing wells. Then we discuss the gross mass balances.

5.2.1 Net oil mass balance

The entities' data supplied for compilation of these "net oil mass balances" were derived using a common method used in the Hydrocarbon Industry. The production rates allocated to each Flow Station, and hence to each well, were established by applying a correction or reconciliation factor, to the field measurements. This factor is derived by dividing the fiscal measurements made at the custody transfer point, by the sum of the measurements taken in the field.

The reason for using such a reconciliation factor is because fiscal measurements are much more accurate than field measurements. Fiscal metering of volumes is normally accurate to +/- 0.25% for liquids and +/- 1% for gas, while field measurements are typically +/- 10%. This reconciliation system uses the accurate "fiscal" measurements to assign corrections to the field metering, enabling more precise volumes to be assigned to each Flow Station, and hence to each well. This system captures any volumes lost due to equipment malfunctions which cause loss of production, such as an individual well or a Flow Station trip etc.; also any losses due to a line leak are calculated and reported; as are the volumes associated with shrinkage due to any remaining gas coming out of solution in the oil, which requires considerable time at atmospheric pressure to happen; it also caters for any inaccuracies in determining the water content of the fluid. All of these aspects typically result in "Reconciliation Factors" (referred to as RF) between 0.92-0.99, which is considered to not justify additional measures. When the RF does drop closer to 0.92 investigations normally take place to find and correct the reason. The cause is normally attributable to such events as a malfunctioning meter giving inaccurate reading; or a watercut device not working correctly; sometimes due to leaking valves, or similar.

Every well is tested approximately once per month to determine the oil, gas and water production rates. At some Stations, the fluids from the well on test flows through a 3-phase separator where the oil, gas and water are physically separated and measured individually. At other locations just the liquids and gas are separated for measurement, with the oil/water content of the liquid being established by taking a representative sample and analysing it in a laboratory. Each operator compiles a Monthly Report of Producing Wells (MRPW), copies of which are sent to DPR. This document reports for every well, how much oil, gas and water was produced that month. These oil and gas volumes are the reconciled figures as described in the preceding paragraph.

Internal hydrocarbon balances were compiled for Addax, Agip, Amni, Atlas, Chevron/Texaco, Conoil, Continental Oil, Dubri, Elf, Express/Conoco, Mobil, Moni Pulo, NPDC, Pan Ocean and Shell.

The data has been tabulated to show "Net Oil Mass Balances", showing the source of the oil by field; its receipt and processing at a terminal; and the export figures, which have been correlated with data from DPR. These net oil tabulations are shown in Appendix B**.**

This approach to hydrocarbon balance is not sufficient to highlight unaccounted oil or to estimate oil theft. For that purpose, suitable measurement arrangements are needed.

5.2.2 Gross oil balances

Net oil balances do not report items such as unaccounted oil, since all that the net oil balance does is to net back the volumes received at the terminal.

The producing companies were requested to provide data to enable a "Gross Liquid Mass Balance" to be compiled. They were requested to show, per production stream flowing to a custody transfer point, be that a Terminal export or a 3rd party transfer point; the following items:

1) Measurements of the gross liquids entering their gathering system.
    a) To include liquids leaving the Flow Stations and entering the production stream flowing to the offtake point.
    b) Third party oil or any other fluids entering the system to be included.
2) Measurements of gross liquids coming out of their gathering system, such as
    a) Transport losses, due to such events as pipeline leaks, whether from corrosion or sabotage.
    b) Water drained.
    c) Storage losses.
    d) Shrinkage due to volume reduction as residual gas comes out of solution.
    e) Changes in stock levels - the opening and closing stock differences.
    f) Transfers to Refineries.
    g) Exports.
    h) Any other identified and measured offtake.
3) unidentified losses, i.e. the difference between all of the liquids measured entering the system and all liquids measured leaving the system, both in barrels and as a percentage.

The "Gross Liquid Mass Balances" compiled are shown in **Appendix B.**

Entities were able to provide the following:

- Chevron provided good data for Escravos. The gross balance compiled gives a good overview and demonstrated that all of the liquids entering this pipeline system do arrive at the terminal. The gross volumes supplied for the other terminals showed that all of the gross liquids leaving the flow stations arrived at the terminal, but unfortunately, the lack of terminal stock information for their other terminals meant an overall balance including exports could not be made.

- Shell's gross balances for Bonny, Forcados and EA field demonstrated that all gross volumes entering the system were accounted for.
- Data for the FPSO Mystras, plus the data from ConOil, Cont.Oil, Pan Ocean, Mobil's QIT and Addax's Knock Taggart, enabled good balances to be compiled demonstrating all gross liquids accounted for. Atlas had a good overall balance apart from one month.
- Agip provided gross to net volumes at Brass and Addax and Chevron for Izombe and Jisike respectively provided gross to net balances, enabling a balance to be compiled for Brass terminal demonstrating all gross liquids accounted for. Agip also provided well production figures for those well feeding into Brass, which did not agree to their gross terminal figures. The figures on Agip's templates from November 2005 also did not agree to these revised numbers. Agip stated that the revised numbers replaced the November templates, without providing any further reconciliation.

The other operators were unable to supply the requested gross volume data.

It may be that Flow Station gross discharge figures, and terminal water drained volumes, are considered to be operational tools which may be discarded once they have served their purpose. The oil has the value, not the water. Detailed information is kept on the oil, perhaps not on the by-product having no value. However no operator has confirmed this in writing.

One company indicated that it was investigating whether this normal reconciliation (RF) approach was appropriate in Nigeria for all cases. This was because the approach assumes that all of the fluids leaving the wells and flowing through the pipeline system to the Terminals can be accounted for. The company indicated that they have experienced unusually low "Reconciliation Factors" and have identified unauthorised removal of hydrocarbons from their pipeline gathering system. A special exercise was undertaken to monitor the incoming flow to one terminal over a period of several days; a significant drop in flow was recorded just after nightfall and a return to normal as daylight approached. The change was too sudden & significant to be the result of thermal change. Shortly after they had identified this reduction in flow, for a period of approximately one month, the Nigerian Navy had patrolled the river areas where unauthorised offtake points had been found. During this period, the flow into the terminal had remained constant night & day. The company is reviewing its metering philosophy and investigating means to stem such an unaccounted oil loss.

For all these reasons, the metering infrastructure and the records do not allow the hydrocarbon balance to address the question of unaccounted oil. As NSWG wishes to obtain information on this issue for the future, a suitable information system mainstreamed into the companies' information and reporting systems, needs to be established to provide the data, without resorting to ad hoc exercises. We recommend that a dialogue be opened involving NSWG, NAPIMS and the companies (OPTS might facilitate this) to agree how to proceed. There may be expenditure implications if additional metering points are required. There is a range of issues on definitions and practices to be applied in arriving at the reported mass balance. These, and the timing of implementation, should be agreed on an industry-wide basis.

5.2.3 Well data

The operators were also asked to provide the annual volumes of oil, gas and water produced by each of their wells for the period under review. The response to this request has been mixed. Mobil promptly provided annual oil, gas and water volumes for their wells exactly as requested; Addax, Atlas, NPDC, Chevron and Shell provided even more information by supplying monthly rather than annual oil, gas and water volumes for their wells. Elf supplied oil production volumes per well but nothing on gas or water rates. Well production data from the other operators was not received.

This data is not being used for analytical purposes as part of the hydrocarbon balance but is available to NSWG.

5.3 Analysis of the Net Oil Balances and Gross Volumes Mass Balances

Summaries of the reconciliations of the gross balances at each terminal are set out below.

Companies were requested to provide gross liquid balances but not all did so. Where the data to compile a gross balance was not received, the net balance information is provided.

The monthly detail of the mass balances for each company may be found in the Appendices.

There are technical differences between operations of different pipeline systems and terminals, in terms of for example the point at which water is drained. Nevertheless, in order to present the data in a standardised format, the presentation of the tables is the same for each system. Therefore, the order of the lines on each table should not be interpreted as implying any particular sequence of physical operations.

5.4 Relationship between export data and hydrocarbon mass balance

The tables in this section reflect the hydrocarbon flow information for each commercial organisation.

For examples:

- the table for “Shell Bonny” refers to the Joint Venture between Shell, NNPC, Elf and Agip. The entitlement to production by that JV is shared between the JV partners according the JV agreement.
- The table for “Forcados terminal” lists all the commercial arrangements producing oil into the system that feds the Forcados terminal. This includes not only the terminal operator but other groupings that make use of the Forcados pipeline complex, by fiscalised injection, to convey crude from their operations to the terminal.

The pipeline networks are set out in schematic diagrams in Appendix A to this report.

Additionally, companies may trade their entitlements rather than lift them, or assign their entitlements in settlement of other transactions between them. Some entitlements are too small to be commercial to lift and these are commonly sold to another party before lifting. For such reasons, the amounts actually lifted by a company may differ from the lifting entitlement.

Bonny Terminal

Shell Bonny	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow station		200.4	209.0	216.3	193.3	257.9	241.6
Water drained		-54.6	-51.1	-60.8	-49.8	-71.1	-72.8
Gross after drainage		**145.8**	**157.9**	**155.5**	**143.5**	**186.8**	**168.8**
Spillages	no data						
Other losses	no data						
Difference on balance		-0.8	-0.8	-1.7	-0.7	-1.1	-0.9
Terminal Receipts (net oil)		**145.0**	**157.1**	**153.8**	**142.8**	**185.7**	**167.9**
Stock change & third parties	assumed	-1.5	0.4	-2.6	-1.0	0.9	2.0
Volumes to refineries		-37.6	-24.1	-46.8	-39.0	-32.3	-23.1
Volumes to export		-105.9	-133.4	-104.4	-102.8	-154.3	-146.8

Chevron to Bonny	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow station		14.0	14.5	14.3	6.2	12.9	18.7
Water drained		-2.7	-3.1	-3.1	-0.9	-2.4	-3.8
Gross after drainage		**11.3**	**11.4**	**11.2**	**5.3**	**10.5**	**14.9**
Spillages	no data						
Other losses	no data						
Difference on balance		-0.1	0.0	0.0	0.0	0.0	0.1
Terminal Receipts (net oil)		**11.2**	**11.4**	**11.2**	**5.3**	**10.5**	**15.0**
Stock change & third parties	assumed	0.5	2.5	0.8	1.1	0.9	0.6
Volumes to refineries							
Volumes to export		-11.7	-13.9	-12.0	-6.4	-11.4	-15.6

Elf Bonny (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil to terminal		7.7	14.9	14.8	14.3	14.0	13.5
Terminal Receipts (net oil)		**7.7**	**14.9**	**14.8**	**14.3**	**14.0**	**13.5**
Stock change & third parties	assumed	0.8	-0.9	1.2	0.1	-0.5	-0.4
Volumes to refineries							
Volumes to export		-8.5	-14.0	-16.0	-14.4	-13.5	-13.1

Bonny Terminal totals	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		214.4	223.5	230.6	199.5	270.8	260.3
Water drained		-57.3	-54.2	-63.9	-50.7	-73.5	-76.6
Gross after drainage		**157.1**	**169.3**	**166.7**	**148.8**	**197.3**	**183.7**
Spillages	no data						
Other losses	no data						
Difference on balance		6.8	14.1	13.1	13.6	12.9	12.7
Terminal Receipts (net oil)		**163.9**	**183.4**	**179.8**	**162.4**	**210.2**	**196.4**
Stock change & third parties		-0.2	2.0	-0.6	0.2	1.3	2.2
Volumes to refineries		-37.6	-24.1	-46.8	-39.0	-32.3	-23.1
Volumes to export		-126.1	-161.3	-132.4	-123.6	-179.2	-175.5

Brass Terminal

Chevron Jisiki to Brass	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		1.7	2.2	2.1	0.7	2.2	2.6
Water drained		-0.4	-0.4	-0.4	-0.1	-0.5	-0.6
Gross after drainage		**1.3**	**1.8**	**1.7**	**0.6**	**1.7**	**2.0**
Spillages	no data						
Other losses		0.1					
Terminal Receipts (net oil)		**1.4**	**1.8**	**1.7**	**0.6**	**1.7**	**2.0**
Stock change & third parties		0.1		0.3	0.1		-0.1
Volumes to refineries							
Volumes to export		-1.5	-1.8	-2.0	-0.7	-1.7	-1.9

Addax Izombe to Brass	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		5.6	6.7	8.7	9.0	9.0	7.7
Water drained		-3.9	-5.3	-7.0	-7.2	-7.0	-6.4
Gross after drainage		**1.7**	**1.4**	**1.7**	**1.8**	**2.0**	**1.3**
Spillages	no data						
Other losses		-0.1	0.1		-0.1		0.1
Terminal Receipts (net oil)		**1.6**	**1.5**	**1.7**	**1.7**	**2.0**	**1.4**
Stock change & third parties		0.2	0.1	-0.1	0.1	0.1	-0.2
Volumes to refineries							
Volumes to export		-1.8	-1.6	-1.6	-1.8	-2.1	-1.2

AENR Agbara to Brass	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		4.1	4.7	6.2	5.1	4.4	5.3
Water drained		-0.6	-0.5	-0.8	-0.8	-0.9	-1.3
Gross after drainage		**3.5**	**4.2**	**5.4**	**4.3**	**3.5**	**4.0**
Spillages	no data						
Other losses		-0.1	-0.1	-0.1	-0.1		-0.1
Terminal Receipts (net oil)		**3.4**	**4.1**	**5.3**	**4.2**	**3.5**	**3.9**
Stock change & third parties		0.3	-0.7	-0.7	1.7		-0.2
Volumes to refineries							
Volumes to export		-3.7	-3.4	-4.6	-5.9	-3.5	-3.7

NAOC to Brass (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		69.7	82.9	93.2	84.3	100.9	105.5
Water drained		-24.1	-29.2	-30.0	-28.1	-31.6	-36.2
Gross after drainage		**45.6**	**53.7**	**63.2**	**56.2**	**69.3**	**69.3**
Spillages	no data						
Other losses		-0.6	-0.8	-1.2	-0.5	-1.2	-1.6
Terminal Receipts (net oil)		**45.0**	**52.9**	**62.0**	**55.7**	**68.1**	**67.7**
Stock change & third parties		-0.6	-0.5	1.9	-2.8	-0.6	1.2
Volumes to refineries							
Volumes to export		-44.4	-52.4	-63.9	-52.9	-67.5	-68.9

Brass total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		81.1	96.5	110.2	99.1	116.5	121.1
Water drained		-29.0	-35.4	-38.2	-36.2	-40.0	-44.5
Gross after drainage		**52.1**	**61.1**	**72.0**	**62.9**	**76.5**	**76.6**
Spillages	no data						
Other losses		-0.7	-0.8	-1.3	-0.7	-1.2	-1.6
Terminal Receipts (net oil)		**51.4**	**60.3**	**70.7**	**62.2**	**75.3**	**75.0**
Stock change & third parties			-1.1	1.4	-0.9	-0.5	0.7
		1.0					
Volumes to refineries		1.0					
Volumes to export		-51.4	-59.2	-72.1	-61.3	-74.8	-75.7

Escravos Terminal

Chevron Escravos	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		149.5	149.4	157.7	134.3	129.1	123.3
Water drained		-11.7	-10.4	-12.7	-13.5	-16.3	-16.4
Gross after drainage		**137.8**	**139.0**	**145.0**	**120.8**	**112.8**	**106.9**
Spillages	no data						
Other losses	no data						
Difference on balance		0.1	1.5	1.6	1.9	0.6	
Terminal Receipts (net oil)		**137.9**	**140.5**	**146.6**	**122.7**	**113.4**	**106.9**
Stock change & third parties		0.8	-1.1	-0.2	-0.2	-0.7	1.1
Volumes to refineries		-28.3	-12.1	-37.3	-38.8	-8.8	-2.2
Volumes to export		-110.4	-127.3	-109.1	-83.7	-103.9	-105.8

Dubri to Escravos	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil to terminal			0.1	0.1	0.1		0.1
Terminal Receipts (net oil)			**0.1**	**0.1**	**0.1**		**0.1**
Stock change & third parties	assumed	0.1		0.1		0.1	-0.1
Volumes to refineries							
Volumes to export		-0.1	-0.1	-0.2	-0.1	-0.1	

Conoil to Escravos	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		4.6	3.1	3.1	2.8	2.5	2.6
Water drained		-2.7	-1.8	-2.0	-1.9	-1.7	-1.8
Gross after drainage		**1.9**	**1.3**	**1.1**	**0.9**	**0.8**	**0.8**
Spillages	no data						
Other losses	no data						
Difference on balance		-0.1			-0.1		
Terminal Receipts (net oil)		**1.8**	**1.3**	**1.1**	**0.8**	**0.8**	**0.8**
Stock change & third parties	assumed	-0.2	-0.1	0.1	0.6		
Volumes to refineries							
Volumes to export		-1.6	-1.2	-1.2	-1.4	-0.8	-0.8

Escravos total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		154.1	152.5	160.8	137.1	131.6	125.9
Water drained		-14.4	-12.2	-14.7	-15.4	-18.0	-18.2
Gross after drainage		**139.7**	**140.3**	**146.1**	**121.7**	**113.6**	**107.7**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences		0.0	1.6	1.7	1.9	0.6	0.1
Terminal Receipts (net oil)		**139.7**	**141.9**	**147.8**	**123.6**	**114.2**	**107.8**
Stock change & third parties		0.7	-1.2		0.4	-0.6	1.0
Volumes to refineries		-28.3	-12.1	-37.3	-38.8	-8.8	-2.2
Volumes to export		-112.1	-128.6	-110.5	-85.2	-104.8	-106.6

Forcados Terminal

Shell Forcados	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow station		209.2	258.0	301.3	245.9	255.7	328.4
Water drained		-97.4	-123.8	-150.9	-127.2	-137.2	-178.1
Gross after drainage		**111.8**	**134.2**	**150.4**	**118.7**	**118.5**	**150.3**
Spillages	no data						
Other losses	no data						
Difference on balance				-0.1			2.0
Terminal Receipts (net oil)		**111.8**	**134.2**	**150.3**	**118.7**	**118.5**	**152.3**
Stock change & third parties		1.5	-1.7	0.5	-0.5	-2.0	3.1
Volumes to refineries		-0.1				-2.1	-13.5
Volumes to export		-113.2	-132.5	-150.8	-118.2	-114.4	-141.9

PanOcean to Forcados	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		2.1	3.9	5.2	4.3	4.5	7.6
Water drained							
Gross after drainage		**2.1**	**3.9**	**5.2**	**4.3**	**4.5**	**7.6**
Spillages	no data						
Other losses	no data						
Difference on balance				-0.1		0.1	
Terminal Receipts (net oil)		**2.1**	**3.9**	**5.1**	**4.3**	**4.6**	**7.6**
Stock change & third parties	assumed	-0.2	-0.7	0.8	-0.6	0.8	-0.9
Volumes to refineries							
Volumes to export		-1.9	-3.2	-5.9	-3.7	-5.4	-6.7

Elf to Forcados (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil to terminal		2.6	2.1	2.8	1.8	0.6	
Terminal Receipts (net oil)		**2.6**	**2.1**	**2.8**	**1.8**	**0.6**	
Stock change & third parties	assumed	-0.9	0.7	0.1	1.0	-0.2	
Volumes to refineries							
Volumes to export		-1.7	-2.8	-2.9	-2.8	-0.4	

NAOC to Forcados (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil to Terminal		1.1	3.7	5.8	4.6	2.9	2.5
Terminal Receipts (net oil)		**1.1**	**3.7**	**5.8**	**4.6**	**2.9**	**2.5**
Stock change & third parties	assumed	-0.3	0.2	-0.1	1.1	-0.6	
Volumes to refineries							
Volumes to export		-0.8	-3.9	-5.7	-5.7	-2.3	-2.5

Forcados terminal (continued)

NPDC	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil to Terminal		1.8	1.9	2.2	2.1	2.1	2.8
Terminal Receipts (net oil)		**1.8**	**1.9**	**2.2**	**2.1**	**2.1**	**2.8**
Stock change & third parties	assumed	0.1	-0.3	0.2	-0.3	0.1	-0.2
Volumes to refineries							
Volumes to export		-1.9	-1.6	-2.4	-1.8	-2.2	-2.6

Forcados total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		211.3	261.9	306.5	250.2	260.2	336.0
Water drained		-97.4	-123.8	-150.9	-127.2	-137.2	-178.1
Gross after drainage		**113.9**	**138.1**	**155.6**	**123.0**	**123.0**	**157.9**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences		3.7	5.8	8.4	6.4	3.6	4.5
Terminal Receipts (net oil)		**119.4**	**145.8**	**166.2**	**131.5**	**128.7**	**165.2**
Stock change & third parties		0.2	-1.8	1.5	0.7	-1.9	2.0
Volumes to refineries		-0.1				-2.1	-13.5
Volumes to export		-119.5	-144.0	-167.7	-132.2	-124.7	-153.7

Olibiri terminal

Chevron to Oloibiri	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow station		16.6	17.3	13.9	9.8	8.1	6.7
Water drained		-0.1	-0.1	-0.1			
Gross after drainage		**16.5**	**17.2**	**13.8**	**9.8**	**8.1**	**6.7**
Spillages	no data						
Other losses	no data						
Difference on balance							
Terminal Receipts (net oil)		**16.5**	**17.2**	**13.8**	**9.8**	**8.1**	**6.7**
Stock change & third parties	assumed	0.1	0.2	-0.6	0.6	0.7	-0.1
Volumes to refineries							
Volumes to export		-16.6	-17.4	-13.2	-10.4	-8.8	-6.6

Continental Oil to Oloibiri	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		4.1	9.9	14.7	14.1	15.6	18.2
Water drained		-0.1	-1.5	-2.8	-2.4	-3.1	-3.2
Gross after drainage		**4.0**	**8.4**	**11.9**	**11.7**	**12.5**	**15.0**
Spillages	no data						
Other losses	no data						
Difference on balance				-0.1	-0.2	-0.1	-0.2
Terminal Receipts (net oil)		**4.0**	**8.4**	**11.8**	**11.5**	**12.4**	**14.8**
Stock change & third parties	assumed	-0.4	-0.1	0.2	-0.5	-0.7	0.1
Volumes to refineries							
Volumes to export		-3.6	-8.3	-12.0	-11.0	-11.7	-14.9

Oloibiri total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		20.7	27.2	28.6	23.9	23.7	24.9
Water drained		-0.2	-1.6	-2.9	-2.4	-3.1	-3.2
Gross after drainage		**20.5**	**25.6**	**25.7**	**21.5**	**20.6**	**21.7**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences				-0.1	-0.2	-0.1	-0.2
Terminal Receipts (net oil)		**20.5**	**25.6**	**25.6**	**21.3**	**20.5**	**21.5**
Stock change & third parties		-0.3	0.1	-0.4	0.1		
Volumes to refineries							
Volumes to export		-20.2	-25.7	-25.2	-21.4	-20.5	-21.5

FPSO Qua Iboe

Mobil Qua Iboe (excl Condensate)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		221.9	215.8	209.9	171.9	171.3	156.5
Water drained		-15.3	-19.2	-16.5	-13.8	-15.7	-17.3
Gross after drainage		**206.6**	**196.6**	**193.4**	**158.1**	**155.6**	**139.2**
Spillages							
Other losses	shrinkage						
Difference on balance		-0.1	-0.2	0.9	-0.6	1.3	-1.4
Terminal Receipts (net oil)		**188.9**	**176.9**	**172.7**	**141.7**	**139.6**	**126.7**
Stock change & third parties		0.2	0.2	-0.9	0.6	-1.3	1.4
Volumes to refineries							
Volumes to export		-189.1	-177.1	-171.8	-142.3	-138.3	-128.1

Mobil Condensate	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow station	N/A						
Water drained	N/A						
Gross after drainage	N/A						
Spillages	N/A						
Other losses	N/A						
Condensate (from Gas balance)		34.7	34.6	34.6	32.7	21.2	26.2
Terminal Receipts (net oil)		**34.7**	**34.6**	**34.6**	**32.7**	**21.2**	**26.2**
Stock change & third parties	assumed	-0.1	-1.0	1.2	-0.4	-0.7	1.0
Volumes to refineries							
Volumes to export		-34.6	-33.6	-35.8	-32.3	-20.5	-27.2

Qua Iboe total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		221.9	215.8	209.9	171.9	171.3	156.5
Water drained		-15.3	-19.2	-16.5	-13.8	-15.7	-17.3
Gross after drainage		**206.6**	**196.6**	**193.4**	**158.1**	**155.6**	**139.2**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences		34.6	34.4	35.5	32.1	22.5	24.8
Terminal Receipts (net oil)		**223.6**	**211.5**	**207.3**	**174.4**	**160.8**	**152.9**
Stock change & third parties		0.1	-0.8	0.3	0.2	-2.0	2.4
Volumes to refineries							
Volumes to export		-223.7	-210.7	-207.6	-174.6	-158.8	-155.3

FPSO KnockTaggart

Addax Knock Taggart	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		9.5	10.8	13.2	16.0	18.6	21.3
Water drained		-6.6	-6.1	-5.8	-5.9	-6.0	-7.6
Gross after drainage		**2.9**	**4.7**	**7.4**	**10.1**	**12.6**	**13.7**
Spillages	no data						
Other losses	shrinkage						
Difference on balance		-0.1		0.1	0.1	-0.1	
Terminal Receipts (net oil)		**2.8**	**4.6**	**7.2**	**9.8**	**11.8**	**13.2**
Stock change & third parties	assumed	-0.3	0.3	-0.4	0.2		-0.2
Volumes to refineries							
Volumes to export		-2.5	-4.9	-6.8	-10.0	-11.8	-13.0

Moni Pulo to Knock Taggart+A408	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil		5.3	8.0	9.1	8.1	6.7	5.8
Terminal Receipts (net oil)		**5.3**	**8.0**	**9.1**	**8.1**	**6.7**	**5.8**
Stock change		-0.5	0.2	0.1	0.2		-0.1
Volumes to refineries							
Volumes to export		-4.8	-8.2	-9.2	-8.3	-6.7	-5.7

Knock Taggart total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		9.5	10.8	13.2	16.0	18.6	21.3
Water drained		-6.6	-6.1	-5.8	-5.9	-6.0	-7.6
Gross after drainage		**2.9**	**4.7**	**7.4**	**10.1**	**12.6**	**13.7**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences		5.2	8.0	9.2	8.2	6.6	5.8
Terminal Receipts (net oil)		**8.1**	**12.6**	**16.3**	**17.9**	**18.5**	**19.0**
Stock change & third parties		-0.8	0.5	-0.3	0.4		-0.3
Volumes to refineries							
Volumes to export		-7.3	-13.1	-16.0	-18.3	-18.5	-18.7

FPSO Mystras

Mystras	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations					4.4	4.7	10.2
Water drained							
Gross after drainage					**4.4**	**4.7**	**10.2**
Spillages	no data						
Other losses	no data						
Difference on balance							
Terminal Receipts (net oil)					**4.4**	**4.7**	**10.2**
Stock change & third parties					-0.1	0.1	-0.1
Volumes to refineries							
Volumes to export					-4.3	-4.8	-10.1

FPSO Sea Eagle

SNEPCO Sea Eagle	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations					0.1	27.0	45.0
Water drained						-0.2	-1.9
Gross after drainage					**0.1**	**26.8**	**43.1**
Spillages	no data						
Other losses	no data						
Difference on balance					-0.1		
Terminal Receipts (net oil)						**26.8**	**43.1**
Stock change & third parties	assumed					-0.7	0.4
Volumes to refineries							
Volumes to export						-26.1	-43.5

FPSO Falcon

Mobil Falcon [net]	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil					0.6	38.8	43.1
Terminal Receipts (net oil)					**0.6**	**38.8**	**43.1**
Stock change & third parties	assumed				-0.6	0.2	0.1
Volumes to refineries							
Volumes to export						-39.0	-43.2

FPSO Spirit

Atlas to Ukpokiti FSO (Independence / Spirit)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		3.2	3.0	2.4	3.1	2.6	1.0
Water drained		-0.5	-1.1	-0.3	-0.4	-1.8	-0.9
Gross after drainage		**2.7**	**1.9**	**2.1**	**2.7**	**0.8**	**0.1**
Spillages	no data						
Other losses	no data						
Difference on balance		-0.1					0.1
Terminal Receipts (net oil)		**2.6**	**1.9**	**2.1**	**2.7**	**0.8**	**0.2**
Stock change & third parties	assumed		0.1	-0.2	0.2		-0.1
Volumes to refineries							
Volumes to export		-2.6	-2.0	-1.9	-2.9	-0.8	-0.1
		2618652	1999036	1881167	2981274	813966	100141

Express: FPSO Independence	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil		7.1	7.4	7.7	5.8	4.2	1.7
Terminal Receipts (net oil)		**7.1**	**7.4**	**7.7**	**5.8**	**4.2**	**1.7**
Stock change		0.5	0.1	-0.1	0.2		-0.1
Volumes to refineries							
Volumes to export		-7.6	-7.5	-7.6	-6.0	-4.2	-1.6

Independence total	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations		3.2	3.0	2.4	3.1	2.6	1.0
Water drained		-0.5	-1.1	-0.3	-0.4	-1.8	-0.9
Gross after drainage		**2.7**	**1.9**	**2.1**	**2.7**	**0.8**	**0.1**
Spillages	no data						
Other losses	no data						
Net oil data plus other differences		7.0	7.4	7.7	5.8	4.2	1.8
Terminal Receipts (net oil)		**9.7**	**9.3**	**9.8**	**8.5**	**5.0**	**1.9**
Stock change & third parties		0.5	0.2	-0.3	0.4		-0.2
Volumes to refineries							
Volumes to export		-10.2	-9.5	-9.5	-8.9	-5.0	-1.7

FPSO Unity

Elf Unity (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil		33.9	35.3	37.3	32.3	36.5	62.6
Terminal Receipts (net oil)		**33.9**	**35.3**	**37.3**	**32.3**	**36.5**	**62.6**
Stock change & third parties	assumed	0.7	0.1	0.1	-0.2	-0.1	-0.2
Volumes to refineries							
Volumes to export		-34.6	-35.4	-37.4	-32.1	-36.4	-62.4

FPSO Gray Warrior

NAE Gray Warrior (net)	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil						3.1	9.8
Terminal Receipts (net oil)		**.**				**3.1**	**9.8**
Stock change & third parties	assumed					-0.1	-0.5
Volumes to refineries							
Volumes to export						-3.0	-9.3

FPSO Ailsa Craig

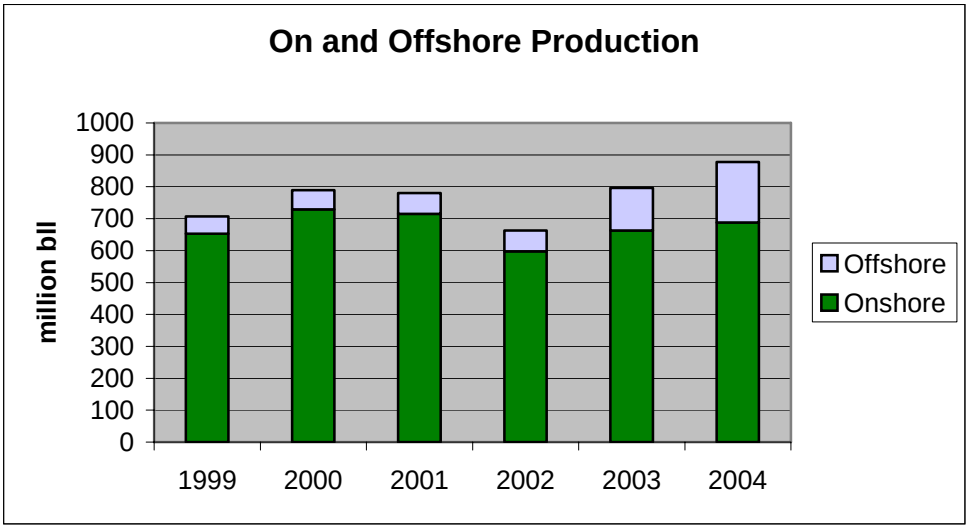
Amni: FPSO Ailsa Craig	MM bbl	1999	2000	2001	2002	2003	2004
Gross volumes from flow stations	no data						
Water drained	no data						
Gross after drainage	no data						
Spillages	no data						
Other losses	no data						
Net oil		2.2	2.2	1.5	1.3	0.9	0.8
Terminal Receipts (net oil)		**2.2**	**2.2**	**1.5**	**1.3**	**0.9**	**0.8**
Stock change	Assumed	-0.1	-0.2	0.4	-0.1	0.1	0.1
Volumes to refineries							
Volumes to export		-2.1	-2.0	-1.9	-1.2	-1.0	-0.9

6 CRUDE EXPORT LIFTINGS

6.1 Summary of exports

Export terminal liftings have been reconciled between DPR and the companies. As explained in paragraph 5.4, the amounts lifted may not, for various legitimate reasons, not correspond to the entitlements inferred in the hydrocarbon balance set out in section 5.

Annual lifted volumes are summarised as follows:



Note: for the purpose of the above analysis, the onshore terminals are considered to be those listed on page 12, though they may process some production from offshore (shallow) areas.

6.2 Methodology

Companies and DPR supplied data as to the quantities lifted from each terminal. The amounts supplied initially differed in many respects. The comparisons were fed back to the entities and the entities undertook bilateral reconciliations with DPR. A comprehensive reconciliation exercise was then organized at which each company in turn attended an audit meeting with us, together with DPR, representatives from COMD and FIRS. At this meeting, remaining items were either resolved or identified for further investigation by the respective entities. Subsequently, COMD held meetings with oil companies to agree the NNPC liftings by terminal. Following the comprehensive exercise, some entities made further corrections to their figures. There was a further meeting chaired by DPR in June which made final adjustments to the export balances and produced a final agreed balance by company and by terminal. The export balances in this report are those supplied to us by DPR following this meeting in June 2006.

6.2.1 Exports from onshore terminals

The summary of onshore liftings, for the six years 1999-2004, per DPR records, is set out below (in million barrels).

Note that there may be several commercial groupings (joint ventures, PSCs, sole risk operations) utilising the same terminal. The identify of the terminal operator is not relevant to the ownership of the liftings.

The tables show, for each terminal, the total oil and condensate lifted from each terminal each year and the amount of NNPC lifting included in the total.

DPR records are maintained principally in terms of the total amounts lifted from each terminal per vessel. They are supported by Bill of Lading. The DPR records are designed to keep full details of the fiscalised export quantities. It was found, in the course of reconciliation, that the beneficial ownership of a cargo seems not to be of equal importance to DPR. This meant that, whereas the absolute volumes exported from each terminal were materially agreed in total, there were, in the initial round of reconciliations, numerous differences between companies as to whose cargo was being exported. These differences were subsequently discussed and mainly resolved between the companies concerned at each terminal.

Companies and DPR signed off on the agreed volumes, including on the volumes per company that were believed to be correct at the time of signing. Our subsequent analytical work on the gross and net mass balances at each terminal indicated that there were differences: these arithmetically arose either as indicating an unexpected mass balance difference or else indicating an error in the export volume of the exporter. These differences were again investigated. Due to the timing of the reconciliation work, DPR has not been advised of subsequent reallocations of cargoes between companies. Therefore the DPR signed off export volumes per company may differ from the volumes subsequently notified to us by the companies, although in most cases the total export volumes from each terminal are unaffected.

Summaries of the mass balances for each operation (eg: Joint Venture, PSC) have been set out above. These have been aggregated to provide the annual terminal totals. Terminal summaries are set out below.

Onshore terminals

	1999	2000	2001	2002	2003	2004	Total for 6 years
	1999	2000	2001	2002	2003	2004	Total for 6 years
Bonny							
Exports per terminal balance	126.1	161.3	132.4	123.6	179.2	175.5	898.1
DPR records	126.1	161.3	132.4	123.6	179.2	175.5	898.1
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Brass							
Exports per terminal balance	51.4	59.2	72.1	61.3	74.8	75.7	394.5
DPR records	51.4	59.2	72.1	61.3	74.8	75.7	394.5
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Escravos							
Exports per terminal balance	112.1	128.6	110.5	85.2	104.8	106.6	647.8
DPR records	112.1	128.6	110.5	85.2	104.8	106.6	647.8
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Forcados							
Exports per terminal balance	119.5	144.0	167.7	132.2	124.7	153.7	841.8
DPR records	119.5	144.0	167.7	132.2	124.7	153.7	841.8
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Oloibiri							
Exports per terminal balance	20.2	25.7	25.2	21.4	20.5	21.5	134.5
DPR records	20.2	25.7	25.2	21.4	20.5	21.5	134.5
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Qua Iboe							
Exports per terminal balance	223.7	210.7	207.6	174.6	158.8	155.3	1130.7
DPR records	223.7	210.7	207.6	174.6	158.8	155.3	1130.7
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Offshore balances

	1999	2000	2001	2002	2003	2004	Total for 6 years
	1999	2000	2001	2002	2003	2004	Total for 6 years
Knock Taggart							
Exports per terminal balance	7.3	13.1	16.0	18.3	18.5	18.7	91.9
DPR records	7.3	13.1	16.0	18.3	18.5	18.7	91.9
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Mystras							
Exports per terminal balance	0.0	0.0	0.0	4.3	4.8	10.1	19.2
DPR records	0.0	0.0	0.0	4.3	4.8	10.1	19.2
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Sea Eagle							
Exports per terminal balance	0.0	0.0	0.0	0.0	26.1	43.5	69.6
DPR records	0.0	0.0	0.0	0.0	26.1	43.5	69.6
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Falcon							
Exports per terminal balance	0.0	0.0	0.0	0.0	39.0	43.2	82.2
DPR records	0.0	0.0	0.0	0.0	39.0	43.2	82.2
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Spirit							
Exports per terminal balance	10.2	9.5	9.5	8.9	5.0	1.7	44.8
DPR records	10.2	9.5	9.5	8.9	5.0	1.7	44.8
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Unity							
Exports per terminal balance	34.6	35.4	37.4	32.1	36.4	62.4	238.3
DPR records	34.6	35.4	37.4	32.1	36.4	62.4	238.3
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Gray Warrior							
Exports per terminal balance	0.0	0.0	0.0	0.0	3.0	9.3	12.3
DPR records	0.0	0.0	0.0	0.0	3.0	9.3	12.3
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ailsa Craig							
Exports per terminal balance	2.1	2.0	1.9	1.2	1.0	0.9	9.1
DPR records	2.1	2.0	1.9	1.2	1.0	0.9	9.1
difference	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

6.3 Export liftings analysis

The export liftings reported by DPR and reported by companies were reconciled and agreed in joint meetings. The annual summary of quantities lifted by each company is set out in the following tables.

Bonny Terminal - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	58.3	85.9	56.8	51.0	82.8	90.0
Shell	42.2	47.8	43.1	40.9	59.4	50.5
Chevron	0.0	0.0	3.6	3.8	3.8	5.7
Elf	18.6	19.8	21.5	20.7	23.8	22.0
Phillips	0.0	0.1	0.0	0.0	0.0	0.0
NAOC	7.1	7.7	7.3	7.1	9.5	7.3
Roundings	-0.1	0.0	0.1	0.1	-0.1	0.0
Total volumes to export	126.1	161.3	132.4	123.6	179.2	175.5

Brass Terminal - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	30.9	35.4	44.1	37.3	44.6	46.5
NAOC	8.9	10.6	11.9	10.6	13.3	13.6
Phillips	8.5	10.4	12.5	10.4	13.5	12.4
AENR	1.1	1.1	1.1	1.2	1.0	1.1
Shell	0.1	0.0	0.9	0.0	0.0	0.9
Addax	1.8	1.6	1.6	1.8	2.2	1.2
Elf	0.1	0.0	0.0	0.0	0.2	0.0
Roundings	0.0	0.1	0.0	0.0	0.0	0.0
Total volumes to export	51.4	59.2	72.1	61.3	74.8	75.7

Escravos Terminal - Exports reported by DPR	1999 MM bbl	2000 MM bbl	2001 MM bbl	2002 MM bbl	2003 MM bbl	2004 MM bbl
NNPC	51.7	67.0	49.6	35.1	56.9	61.8
Chevron	58.7	60.3	59.5	48.6	47.0	44.1
Dubri	0.1	0.1	0.2	0.1	0.1	0.0
Conoil	1.6	1.2	1.2	1.4	0.8	0.8
Roundings	0.0	0.0	0.0	0.0	0.0	-0.1
Total volumes to export	112.1	128.6	110.5	85.2	104.8	106.6

Forcados Terminal - Exports reported by DPR	1999 MM bbl	2000 MM bbl	2001 MM bbl	2002 MM bbl	2003 MM bbl	2004 MM bbl
NNPC	62.7	80.6	91.5	71.1	68.5	77.4
Shell	36.5	40.2	44.9	37.5	33.0	46.4
Phillips	0.2	0.7	1.2	0.8	0.7	0.5
Panocean	0.8	1.2	2.4	1.5	2.2	2.7
Elf	11.6	12.4	16.8	13.0	11.8	15.4
NAOC	5.9	6.9	8.7	6.7	6.5	8.6
NPDC	1.9	1.6	2.4	1.8	2.2	2.5
Roundings	-0.1	-0.1	-0.2	-0.2	-0.2	0.2
Total volumes to export	119.5	143.5	167.7	132.2	124.7	153.7

Olibiri Terminal - Exports reported by DPR	1999 MM bbl	2000 MM bbl	2001 MM bbl	2002 MM bbl	2003 MM bbl	2004 MM bbl
NNPC	9.0	11.0	7.5	6.6	4.7	3.8
Texaco	3.9	2.7	2.9	2.0	1.7	1.4
Continental	3.6	8.3	12.0	11.0	11.7	15.0
Chevron	3.7	3.8	2.8	1.8	2.3	1.4
Roundings	0.0	-0.1	0.0	0.0	0.1	-0.1
Total volumes to export	20.2	25.7	25.2	21.4	20.5	21.5

FPSO Qua Iboe - Exports reported by DPR	1999 MM bbl	2000 MM bbl	2001 MM bbl	2002 MM bbl	2003 MM bbl	2004 MM bbl
NNPC	134.0	129.1	124.7	104.2	96.2	92.3
Mobil	89.7	81.5	83.0	70.4	62.6	63.0
Roundings	0.0	0.1	-0.1	0.0	0.0	0.0
Total volumes to export	223.7	210.7	207.6	174.6	158.8	155.3

FPSO KnockTaggart - Exports reported by DPR	1999 MM bbl	2000 MM bbl	2001 MM bbl	2002 MM bbl	2003 MM bbl	2004 MM bbl
NNPC	0.0	0.0	0.0	0.0	0.0	3.5
Addax	2.4	5.0	6.8	9.9	11.8	9.6
Moni Pulo	4.8	8.2	9.2	8.3	6.7	5.7
Roundings	0.1	-0.1	0.0	0.1	0.0	-0.1
Total volumes to export	7.3	13.1	16.0	18.3	18.5	18.7

FPSO Mystras - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
AENR	0.0	0.0	0.0	2.0	3.8	7.9
NPDC	0.0	0.0	0.0	2.3	1.1	2.1
Roundings	0.0	0.0	0.0	0.0	-0.1	0.1
Total volumes to export	0.0	0.0	0.0	4.3	4.8	10.1

FPSO Sea Eagle - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	0.0	0.0	0.0	0.0	0.0	8.2
Shell	0.0	0.0	0.0	0.0	19.6	27.3
Elf	0.0	0.0	0.0	0.0	3.2	3.6
Agip	0.0	0.0	0.0	0.0	3.3	4.4
Roundings	0.0	0.0	0.0	0.0	0.0	0.0
Total volumes to export	0.0	0.0	0.0	0.0	26.1	43.5

FPSO Falcon - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	0.0	0.0	0.0	0.0	12.3	14.2
Mobil	0.0	0.0	0.0	0.0	26.6	29.0
Roundings	0.0	0.0	0.0	0.0	0.1	0.0
Total volumes to export	0.0	0.0	0.0	0.0	39.0	43.2

FPSO Spirit - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
CAMAC	0.1	0.1	0.1	0.1	0.0	0.0
Atlas	2.6	2.0	1.9	3.0	0.8	0.1
Express	7.5	7.5	7.6	6.0	4.1	1.5
Roundings	0.0	-0.1	-0.1	-0.2	0.1	0.1
Total volumes to export	10.2	9.5	9.5	8.9	5.0	1.7

FPSO Unity - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	20.6	20.2	22.7	19.7	18.1	18.2
EPNL	14.0	15.2	14.7	12.3	18.3	44.2
Roundings	0.0	0.0	0.0	0.1	0.0	0.0
Total volumes to export	34.6	35.4	37.4	32.1	36.4	62.4

FPSO Gray Warrior - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	0.0	0.0	0.0	0.0	1.0	0.8
NAE	0.0	0.0	0.0	0.0	1.0	4.4
SNEPCO	0.0	0.0	0.0	0.0	1.0	4.1
Roundings	0.0	0.0	0.0	0.0	0.0	0.0
Total volumes to export	0.0	0.0	0.0	0.0	3.0	9.3

Ailsa Craig - Exports reported by DPR	1999	2000	2001	2002	2003	2004
	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl	MM bbl
NNPC	0.0	0.0	0.0	0.0	0.0	0.0
Amni	2.1	2.0	1.9	1.2	1.0	0.9
Roundings	0.0	0.0	0.0	0.0	0.0	0.0
Total volumes to export	2.1	2.0	1.9	1.2	1.0	0.9

6.4 NNPC COMD liftings (exports and refinery supplies)

6.4.1 NNPC exports

NNPC exports comprise: -

1. Direct liftings from export terminals
2. Liftings of crude allocated for domestic refining but not used in the refineries and accordingly exported

In addition, when agreeing exports with DPR, COMD included 0.8m tonnes of crude exported by it from FPSO Gray Warrior under a trial marketing agreement with NAE. COMD have said that NAE is liable for the PPT and royalty payments on this volume of crude. So whilst NNPC actually exported this crude, it is more in the nature of a settlement of a liability between NAE and NNPC by means of a crude allocation and it appears that NAE should be deemed to be the exporter.

NNPC exports, with this NAE volume highlighted, were as follows.

Exports					
	COMD				
	Domestic crude	Direct	Re NAE trial marketing	Total	Per DPR
1999	32.7	334.5	0.0	367.2	367.2
2000	72.6	356.6	0.0	429.2	429.2
2001	59.3	337.5	0.0	396.8	396.8
2002	84.7	240.5	0.0	325.2	325.2
2003	113.2	272.0	0.0	385.2	385.3
2004	113.9	301.9	0.8	416.6	416.7

6.4.2 Domestic crude

The domestic crude allocation was sent for refining or exported during the period in the following volumes.

Domestic crude allocation			
	Exported	Supply to refineries	Total
1999	32.7	65.8	98.5
2000	72.6	36.2	108.8
2001	59.3	84.1	143.4
2002	84.7	78.9	163.6
2003	113.2	44.2	157.4
2004	113.9	38.9	152.8

6.4.3 Supply to refineries

There are differences in the volumes of crude supplied to the refineries as reported by NNPC and by the oil companies. There are also differences between the volumes of crude supplied to the refineries as reported by COMD and by PPMC (for the refineries).

Supply to refineries								
	COMD Bbls 000	Oil companies Bbls 000	Difference Bbls 000		COMD Bbls 000	Difference Bbls 000	Reported by refineries Bbls 000	Tonnes 000
1999	65.8	66.0	***-0.2***		65.8	***32.7***	98.5	13.4
2000	36.2	36.2	***0.0***		36.2	***9.9***	46.1	6.3
2001	84.1	84.1	***0.0***		84.1	***-2.9***	81.2	11.1
2002	78.9	77.8	***1.1***		78.9	***-2.3***	76.6	10.5
2003	44.2	43.3	***0.9***		44.2	***-6.2***	38.0	5.2
2004	38.9	38.9	***0.0***		38.9	***-11.2***	27.7	3.8

The reconciliation process between COMD and the oil companies, and between COMD and PPMC, needs to be improved so that any differences are identified promptly and resolved quickly.[1]

6.4.4 NNPC exports by terminal

Export volumes were reported to us by DPR following the June reconciliation meeting.

Bbls millions 1999 - 2004 Onshore terminals

Terminal	Terminal Operator	Total	NNPC
Bonny	Shell	898.1	424.8
Brass	Agip	394.5	238.8
Escravos	Chevron	647.8	322.1
Forcados	Shell	841.8	452.0
Olibiri	Chevron / Texaco	134.5	42.6
Qua Iboe	Mobil	1,130.7	680.6
Total		**4,047.4**	**2,160.9**

[1] COMD have stated that a monthly meeting Is now held between themselves, the refineries and oil companies to agree these balances. They have said that documentation requires improvement to ensure the process is effective.

Bbls millions 1999 - 2004 Offshore terminals

	Operator	Total	NNPC
KnockTaggart	Addax	91.9	3.5
Mystras	AENR	19.2	0.0
Sea Eagle	Shell	69.6	8.2
Falcon	Mobil	82.2	26.5
Spirit	Express	44.8	0.0
Unity	Elf	238.3	119.5
Gray Warrior	NAE	12.3	1.8
Ailsa Craig	Amni	9.1	0.0
Total		**567.4**	**159.5**

Total - onshore and offshore	**4,614.8**	**2,320.4**

6.5 Volumes for assessing PPT and Royalty

In this section we discuss the differences between the volumes that provide the base for royalty calculation and PPT calculations. We then compare these volumes against the outputs from the hydrocarbon mass balance.

6.5.1 Table of company PPT and Royalty volumes

We reviewed returns from a sample of companies and compared the volumes they had returned for PPT self-assessment purposes with the reconciled export volumes.

We obtained volumes used for PPT and Royalty from JV companies using templates. We also obtained the companies' PPT and Royalty returns for the period under review.

These volumes were reconciled with export volumes which had been reconciled in the Physical Audit between the JV Companies and DPR.

The JV companies used export volumes to calculate Royalty with the exception of Chevron and ELF who used production volumes. For these companies (ELF and Chevron), their export volumes data did not contain the Royalty parameters particularly field landscape/depth. Consequently, we could not use the reconciled export volume to generate their Royalty value. The production volumes the companies reconciled with DPR were therefore used to calculate their Royalty values. The volumes in both cases were higher than export volumes.

Generally, there were no material differences between the volumes the companies used for PPT and Royalty. It is nevertheless imperative that DPR should standardize the volumes applicable for Royalty and ensure that regular assessments are raised on the JV companies thereon.

For PSCs and Independent companies, PPT and Royalty volumes were not reconciled.

In summary, for the six years period, the volumes compare as follows:

Comparison of Physical Volumes and Volumes reported in PPT Returns.

Company	Total		
	Reconciled Vol.	PPT Return Vol.	Difference
SHELL	571,292,684	571,292,684	-
CHEVRON	334,981,000	336,421,000	(1,440,000)
COCNL	15,798,000	14,812,000	986,000
TOPCON	14,656,000	14,797,000	(141,000)
NAOC	165,954,000	165,892,000	62,000
ELF	332,941,000	333,847,000	(906,000)
MOBIL	509,562,000	509,562,000	-
TOTAL	**1,945,184,684**	**1,946,623,684**	**(1,439,000)**

*

Comparison of Physical Volumes and Volumes used by Companies for Royalty

Company	Total		
	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference
SHELL	571,292,684	571,292,684	-
CHEVRON	339,067,900	335,684,000	3,383,900
COCNL	14,415,000	14,396,000	19,000
TOPCON	14,415,000	14,396,000	19,000
NAOC	165,892,000	165,954,000	(62,000)
ELF	339,779,000	332,941,000	6,838,000
MOBIL	512,305,000	512,305,000	-
TOTAL	**1,957,166,584**	**1,946,968,684**	**10,197,900**

+

All units are in Barrels.

* Elf: The difference in 2003/2004 represents Ekanga production, included in volumes for PPT but not included in reconciled export volume.

+ Elf: The difference arises because reconciled volumes are based on exports whereas EPNL calculates Royalty on Production volumes.

The following tables set out the comparison for the years 1999 to 2004.

Reconciliation of Physical Volumes and Volumes used by Companies for PPT as set out in PPT Returns.

Company	1999			2000			2001		
	Reconciled Vol.	PPT Return Vol.	Difference	Reconciled Vol.	PPT Return Vol.	Difference	Reconciled Vol.	PPT Return Vol.	Difference
SHELL	78,785,810	78,785,810	-	88,024,462	88,024,462	-	88,850,983	88,850,983	-
CHEVRON	58,679,000	58,679,000	-	60,268,000	60,268,000	-	63,107,000	63,107,000	-
COCNL	3,652,000	3,652,000	-	3,796,000	3,796,000	-	2,836,000	2,836,000	-
TOPCON	3,940,000	3,940,000	-	2,665,000	3,286,000	(621,000)	2,936,000	2,905,000	31,000
NAOC	21,830,000	21,830,000	-	25,183,000	25,183,000	-	27,945,000	27,945,000	-
ELF	44,240,000	44,240,000	-	47,317,000	47,317,000	-	52,956,000	52,956,000	-
MOBIL	89,694,000	89,694,000	-	81,537,000	81,537,000	-	82,962,000	82,962,000	-
TOTAL	**300,820,810**	**300,820,810**	**-**	**308,790,462**	**309,411,462**	**- 621,000**	**321,592,983**	**321,561,983**	**31,000**

Reconciliation of Physical Volumes and Volumes used by Companies for Royalty

Company	1999			2000			2001		
	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference
SHELL	78,785,810	78,785,810	-	88,024,462	88,024,462	-	88,850,983	88,850,983	-
CHEVRON	60,606,000	57,034,000	3,572,000	61,896,000	61,869,000	27,000	64,187,000	64,252,000	(65,000)
COCNL	3,309,000	3,309,000	-	3,436,000	3,435,000	1,000	2,768,000	2,769,000	(1,000)
TOPCON	3,309,000	3,309,000	-	3,436,000	3,435,000	1,000	2,768,000	2,769,000	(1,000)
NAOC	21,830,000	21,830,000	-	25,183,000	25,183,000	-	27,945,000	27,945,000	-
ELF	43,393,000	44,240,000	(847,000)	50,088,000	47,317,000	2,771,000	52,366,000	52,956,000	(590,000)
MOBIL	89,485,000	89,485,000	-	84,578,000	84,578,000	-	82,974,000	82,974,000	-
TOTAL	**300,717,810**	**297,992,810**	**2,725,000**	**316,641,462**	**313,841,462**	**2,800,000**	**321,858,983**	**322,515,983**	**(657,000)**

Reconciliation of Physical Volumes and Volumes used by Companies for PPT as set out in PPT Returns.

Company	2002			2003			2004		
	Reconciled Vol.	PPT Return Vol.	Difference	Reconciled Vol.	PPT Return Vol.	Difference	Reconciled Vol.	PPT Return Vol.	Difference
SHELL	78,422,661	78,422,661	-	112,025,318	112,025,318	-	125,183,450	125,183,450	-
CHEVRON	52,368,000	52,368,000	-	50,818,000	51,312,000	(494,000)	49,741,000	50,687,000	(946,000)
COCNL	1,787,000	1,787,000	-	2,281,000	1,793,000	488,000	1,446,000	948,000	498,000
TOPCON	1,968,000	1,968,000	-	1,750,000	1,750,000	-	1,397,000	948,000	449,000
NAOC	24,395,000	24,396,000	(1,000)	32,683,000	32,620,000	63,000	33,918,000	33,918,000	-
ELF	45,988,000	45,988,000	-	57,220,000	57,401,000	(181,000)	85,220,000	85,945,000	(725,000)
MOBIL	70,362,000	70,362,000	-	89,904,000	89,904,000	-	95,103,000	95,103,000	-
TOTAL	**275,290,661**	**275,291,661**	**(1,000)**	**346,681,318**	**346,805,318**	**(124,000)**	**392,008,450**	**392,732,450**	**(724,000)**

Reconciliation of Physical Volumes and Volumes used by Companies for Royalty

Company	2002			2003			2004		
	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference	Royalty Vol. Per audit	Royalty Vol. Per Company	Difference
SHELL	78,422,661	78,422,661	-	112,025,318	112,025,318	-	125,183,450	125,183,450	-
CHEVRON	51,801,900	51,774,000	27,900	50,660,000	50,771,000	(111,000)	49,917,000	49,984,000	(67,000)
COCNL	1,952,000	1,932,000	20,000	1,612,000	1,613,000	(1,000)	1,338,000	1,338,000	-
TOPCON	1,952,000	1,932,000	20,000	1,612,000	1,613,000	(1,000)	1,338,000	1,338,000	-
NAOC	24,396,000	24,395,000	1,000	32,620,000	32,683,000	(63,000)	33,918,000	33,918,000	-
ELF	45,582,000	45,988,000	(406,000)	59,756,000	57,220,000	2,536,000	88,594,000	85,220,000	3,374,000
MOBIL	70,121,000	70,121,000	-	90,533,000	90,533,000	-	94,614,000	94,614,000	-
TOTAL	**274,227,561**	**274,564,661**	**(337,100)**	**348,818,318**	**346,458,318**	**2,360,000**	**394,902,450**	**391,595,450**	**3,307,000**

7 MEASUREMENT: PRODUCTION, TRANSMISSION AND EXPORT

7.1 Measurement issues

A number of important issues have arisen during the course of the audit that relate to the measurement of crude oil and petroleum products.

1. Lack of standard definitions and measurement points
2. Inadequate measurement equipment (meters, sampling equipment, temperature and pressure equipment)
3. Absence of regulatory enforcement over a variety of activities relating to assessment and reporting of quantities of crude oil and petroleum products
4. Inconsistent application of existing procedures
5. No culture of striving to follow international best practices

The consequence of these weaknesses can be seen in a number of areas, some of which are crucial to protecting the government's legitimate income from exploitation of the country's crude oil reserves both through correct assessment of tax revenues and also through ensuring that full value is received by NNPC for its share of crude and petroleum product sales. Examples of these consequences are: -

a. Lack of clarity over the volumes to be used for calculation of PPT and royalty, because there is no standard regime of where and to what level of accuracy crude oil flows should be measured
b. Lack of consistency between companies in volumes used for calculation of PPT and royalty, for similar reasons
c. Poor processes for agreement of volumes between entities (e.g. exports, transfers to refineries, hydrocarbon mass balance)
d. Inability to distinguish losses of crude and products through pipeline vandalism from losses due to poor maintenance, accidental mis-reporting of movements by operators (including NNPC) or differences for other reasons
e. No mechanisms in place to address any mis-measurements or losses that are discovered.
f. Inconsistency or lack of information to be used in standard reporting processes, leading to invalid comparisons and poor control over physical flows

These issues are discussed further in the paragraphs that follow.

7.2 Methodology

The JV companies and a sample of smaller operators were asked to complete a questionnaire and an information template about their processes and procedures for measurement of hydrocarbon flows. DPR also completed a questionnaire and template and provided an over view of what they do, mainly concentrating on the crude oil

terminal operations. Data on wellhead measurement requirement was very weak in the response.

The information provided was discussed with the companies and with DPR and visits were made to terminals to observe measurement processes in practice, including fiscalisation of crude. These meetings with the operators and DPR highlighted that most questionnaires had not been fully completed and that the practice was very different for some operators. Only one operator re-submitted the questionnaire in the light of the discussions held. Most operators stated that they did not know what the overall uncertainty of measurement was for wellhead and flow stations. They only agreed on the ship to shore measurement difference.

7.3 Hydrocarbon measurement

In order to be able to determine volumes of crude oil on a basis that enables comparison of flows from different sources measured at different times, it is necessary to measure the quantity of oil, gas and water and also temperature and pressure.

The purpose of the measurement determines the degree of accuracy that is acceptable, since greater accuracy of measurement requires more expensive equipment. It is therefore acceptable to have less frequent and less accurate measurement of flows at the wellhead, with measurement becoming more frequent and more accurate as the crude reaches points of custody transfer. Level of accuracy needs to be specified by DPR to ensure that all operators are measuring the hydrocarbons in a consistent way.

Companies stated that measurements were made at the wellhead and at flow stations, and at fiscal transfer points. There was no consistency in what was measured except at points of fiscal measurement and the measurements at wellheads were not necessarily taken regularly since equipment needed to be transported to the wellhead at the time because it was otherwise liable to be stolen, hence the reliance on gauges rather than transmitters.

The hydrocarbon fiscal transfer rules in Nigeria require the identification of all custody transfer points both internal to refineries and gas plants, and also to oil export and LNG plant to export.

The following points of fiscal custody transfer exist:

- Injection by producers into another company's infrastructure (pipeline or export point)
- Custody transfer of crude oil to the domestic refineries
- Oil export from land based terminals
- Oil export from offshore FSO/FPSO vessels
- Sales of associated and non-associated gas to NGC and NLNG
- Jetty transfers of petroleum products into PPMC depots.

7.4 Regulation and Fiscalisation

DPR provided a "Manual of Procedure Guides for the Petroleum Inspectorate" in response to the NEITI audit request for a copy of their measurement procedures. This was the only procedural guide that DPR in Lagos were able to provide; They were

unable to provide the custody transfer guide referred to below, nor to the equivalent guide for upstream measurement at wellheads and flow stations.

The “Manual of Procedure Guides” has only two measurement guidelines, on how to prove the meter and on ship to shore differences. It makes no reference to two other documents that DPR inspectors referred to a number of times during our discussion with them in Lagos and during observation of the fiscalisation process at a terminal.

There were other documents, at the terminals visited, which had not been updated since they were originally written, suggesting there is no process for ensuring procedures are standard and current and so that full advantage is taken of international best practice. For example, we were shown by an operator a document in current use entitled “Procedure Guide for the determination of the quantity of crude oil and petroleum products at custody transfer points *Rev. September 1994*".

DPR guidelines do not specify the accuracy of the metering at any of the stages e.g. wellhead, flow station or custody transfer. All they specify is the maximum ship to shore difference. Guidelines should give operators advice on the overall acceptable uncertainty of the measurement.

There is a comprehensive guideline on calibration of export meters using a prover loop. However, these meters were not used to measure the export quantities – instead, manual tank dips (which are less accurate) were used for fiscal custody transfer.

The guidelines do not specify the type of thermometer to be used to measure the temperature of the crude. Mercury in glass thermometers were used at the terminals visited – these are not as accurate as digital thermometers, which can be calibrated and proved on site. The temperature of the crude has a great impact on the volume being discharged and it is important that suitable measurement equipment and processes are specified and followed. The absence of these can give rise to significant errors.

DPR gave inconsistent responses when asked which volumes should be used for Royalty calculations. The DPR in Lagos stated that the appropriate volumes were those measured at the flow station using the average API for the field. However, DPR terminal inspectors said that royalty was payable based on sales from the terminal and the blended API of the crude loaded onto the tanker.

DPR staff said they were prepared to waive measurement in difficult areas of the Niger delta, meaning that wellhead measurements have to be estimated. They also showed no interest in transit losses between flow stations and terminals. These are clearly factors that make the assessment of upstream volumes for use in royalty calculations difficult; however, there should be a clear statement from the regulator on this issue, after consultation with the industry.

7.5 Determination of volumes across operations

There are several areas where there is lack of consistency in measurements of quantities and presentation of volumes.

The companies have presented mass balances that are in general based on fiscalised volumes worked back to gross volumes. This is said to have been unavoidable because of the lack of suitable metering at the points required by the audit. Other companies have simply provided net oil balances and have not provided any gross data. However, the purpose of the mass balance was to develop data from which the extent of unaccounted losses could be established. The approach adopted by the companies cannot by definition achieve that purpose. The extent to which metering should be put in place at strategic points in the transmission system requires informed debate.

In the absence of any guidance from DPR, there have been definition issues surrounding the volumes that should be used for royalty calculations. DPR admitted that no operator had reported any losses caused by theft and that they did not want to know transit losses. Different companies have used different volumes and a standard industry practice is lacking. It is said that the choice of volume to be used is driven by the availability of sufficiently accurate measurement systems.

Some companies separate water from crude only at tank farms at the export terminals whereas others separate water at an earlier point. It is argued that reliable measurement is only possible after separation and indeed multiphase metering technology requires careful handling if it is to provide reliable results. Companies take decisions on separation on economic and risk grounds. If royalty assessments were to be based on measurements other than at the terminals, there are technical and financial issues to address.

The determination of export volumes required extensive work before these were agreed between DPR, NNPC and the companies. Similarly, we have tabled Section 6.3.3) different volumes for transfers of crude to the refineries and receipts of crude by the refineries, as provided to us by the companies, by COMD and by PPMC.

7.6 Custody of crude

Only two operators admitted loss of production from theft. They said the amount lost varies but is a lot less than a few years ago. On average, operators estimated it amounts to around 20,000 barrels per day (for each operator) stolen between 20:00 and 04:00. They can see this from the dip in production during this time.

The issue of responsibility for custody of crude in transit in pipelines has traditionally been played down in Nigeria. One of the reasons has been the difficulty of measurement. Other reasons include the externalities of security etc. If the metering issue were to be resolved, it would clear the way for an open discussion on the custody question.

For these reasons, the metering arrangements are important. The broad findings of the audit have been that, apart from fiscalisation metering, the industry uses field measurement systems mainly for operational purposes. The audit found that there is no system of reliance on field metering other than for operational management. Operational

records may not be maintained for long periods and hence the measurement uncertainty cannot be determined. Consequently, it has not been necessary to verify processes of field measurement for the purpose of the audit. In the light of the findings, especially as to the variety of practices in use between companies, we have however asked companies and DPR to tell us about their metering philosophy and practices. Responses to these questions are appended to this report.

7.7 Recommendations

We recommend that:

(a) Each operator should analyse its pipeline network to identify the important nodes where additional metering would quickly highlight unidentified losses. Meters should be installed at these points to, quickly show any unaccounted drop in flow and enable a rapid response to a more precise area. These meters need not be to fiscal standards because the trending of such flow will reveal any sudden changes and the monthly reconciliation factors will reveal any constant shortages.

(b) A monthly “Gross Volumes Mass Balance” should in future be compiled by all operators to be used for management purposes and retained for NEITI audit. This should show what enters the system, such as the gross volumes leaving the Flow Stations; 3rd party injections; what is metered at the nodes mentioned in the previous item; and a comparison made with what leaves the system, such as the water drained, spills, and the oil volumes arriving in the terminal or custody transfer point. Monthly Gross Reconciliation Factors should be included to highlight the level of field control and fluctuations in reconciliation factors should be explained.

(c) Wellhead metering such 3-phase metering is technically difficult and is very expensive to buy and to maintain, requiring an electric power source. The benefits of simple multiphase meters at the Flow Station inlet manifolds should be evaluated and installed if economically justified.

(d) Flow proportional sampling or water in oil meters should be used to get a better assessment of the water-cut in the export crude. This would improve the “Net Oil Mass Balance”.

(e) The “Net Oil Mass Balances” should be compiled on a quarterly basis by all operators and agreed with DPR. The process of compiling net oil balances for this report revealed weaknesses in record keeping by companies, which regular preparation and agreement would improve.

(f) DPR should draw up or revise suitable guidelines for measurement of crude and liquid flows throughout the system and should make these available to company operations and maintenance staff and DPR Inspectors at all sites. DPR staff should be trained in the requirements of these guidelines. These guidelines should be updated annually.

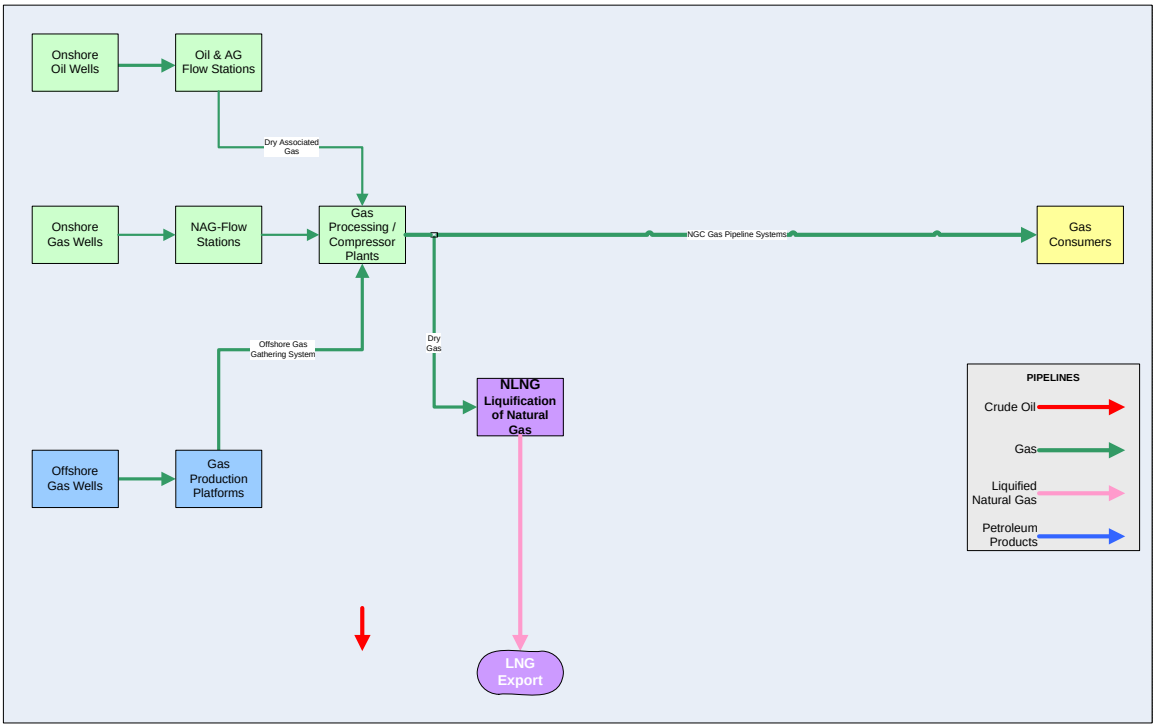
(g) After consultation with the industry, DPR should specify the level of accuracy required when measuring crude oil and liquid flows at different points in the system and should also standards for measurement of temperature and pressure at these measurement points.

The industry in Nigeria is not using standardised definitions. This has led to differing interpretations of; for example the definitions of gross liquid mass balance and a lack of common understanding of procedures and practices across the industry. We are collating the individual company definitions of the hydrocarbon mass balance as an important step in developing a standard across the industry. This includes proposing standardised definitions and recommending how to clarify critical practices that require a common understanding between the entities. This applies particularly to the point in the flow stream at which Royalty and PPT should be applied. This will be produced in conjunction with the preparation of standard templates for the next NEITI audit. At this stage, it is not possible to be confident that all Nigerian industry practices have been captured.

8 GAS SYSTEM

8.1 System Overview

The Gas system is represented by the highlighted flows in the flow diagram below; more detailed diagrams are included in Appendix A.



The Gas system consists of:

- Upstream Gas: the gas fields and gas gathering infrastructure that gathers the gas for delivery into the gas transmission pipeline network. This is usually a custody transfer point.
- Downstream Gas: the gas transmission and distribution infrastructure that transports the gas from the upstream to the customer.

The physical structure of the Nigerian gas industry consists of the following:

- Producers who gather the gas, and pass it onto NGC at a custody transfer point.
- NGC the Nigerian Gas Company who own and operate the majority of the gas transmission network, who buy gas from the producers and sell the gas on to large process users and resellers.
- Consumers who if large process users such as NEPA (PHCN) will buy the gas from either NGC or is some cases direct from the Producers, or if smaller users will buy the gas from resellers.
- NLNG, Nigeria Liquefied Natural Gas Limited, buys gas from three joint venture (JV) operators (SPDC, NAOC, EPNL) and produces Liquefied Natural Gas (LNG) for export.

8.2 System Development

8.2.1 Upstream infrastructure

Historically gas was seen as an undesirable by-product of oil production, a nuisance that needed to be disposed of as cheaply as possible. This was because there was no local gas market for this gas and the cost of installing infrastructure to develop a local gas market was seen as prohibitive. As a result of this perspective a number of possibly unintended consequences followed:

- **No Gas Law.** Nigeria did not have, and still does not have any 'Gas Law' at all, although a new Gas Law is currently being developed. (NB: Gas Law would cover a variety of areas, but some of the key areas would be gas quality, and gas metering, since normally the local collector of excise and taxes would need an accurate assessment of gas flows for fiscal purposes, irrespective of the customers needs.)
- **No gas metering legislation or standards**. In the light of the above, Nigeria does not have any formal mechanisms for checking the accuracy of gas meters, nor does it have any standards for the quality and standards of meters installed.
- **Gas flaring not previously metered**. In the context that gas was a nuisance by-product of oil where Associated Gas was found it would simply be flared in order to enable the producers to remove the oil. Whilst historically gas meters have not been installed on the flaring streams, many of the producers have installed gas meters on new gas fields where gas is being flared over the last few years, and where possible many companies are installing meters on older plant too.
- **Volume sales rather than energy sales**. Also when a gas sale was agreed in the early years of development a simple volume was used, with an estimate for the calorific value, and temperature and pressure correction. (NB: At the time when these agreements were put in place, this simplistic approach was not necessarily wrong).

As the upstream oil and gas industry developed in Nigeria increasing amounts of gas were being flared. There was increasing political pressure on Nigeria to reduce flaring initially by 2004 and now 2008. Solutions begun to be explored to resolve the gas flaring problem, which involved amongst others the development of local gas markets and LNG projects.

8.2.2 Downstream Infrastructure

The Nigerian Gas Company Limited (NGC) was established in 1988 as a subsidiary of the NNPC. NGC owns and operates the majority of the downstream gas transmission and distribution infrastructure in Nigeria. There are some exceptions such as the pipeline owned by Chevron which NGC operates and the pipeline that feeds NLNG directly which is owned by NLNG but is operated by NGC. However in general NGC can be regarded at the monopoly transporter and marketer of downstream gas in Nigeria. Currently NGC operates 8 gas supply systems in Nigeria:

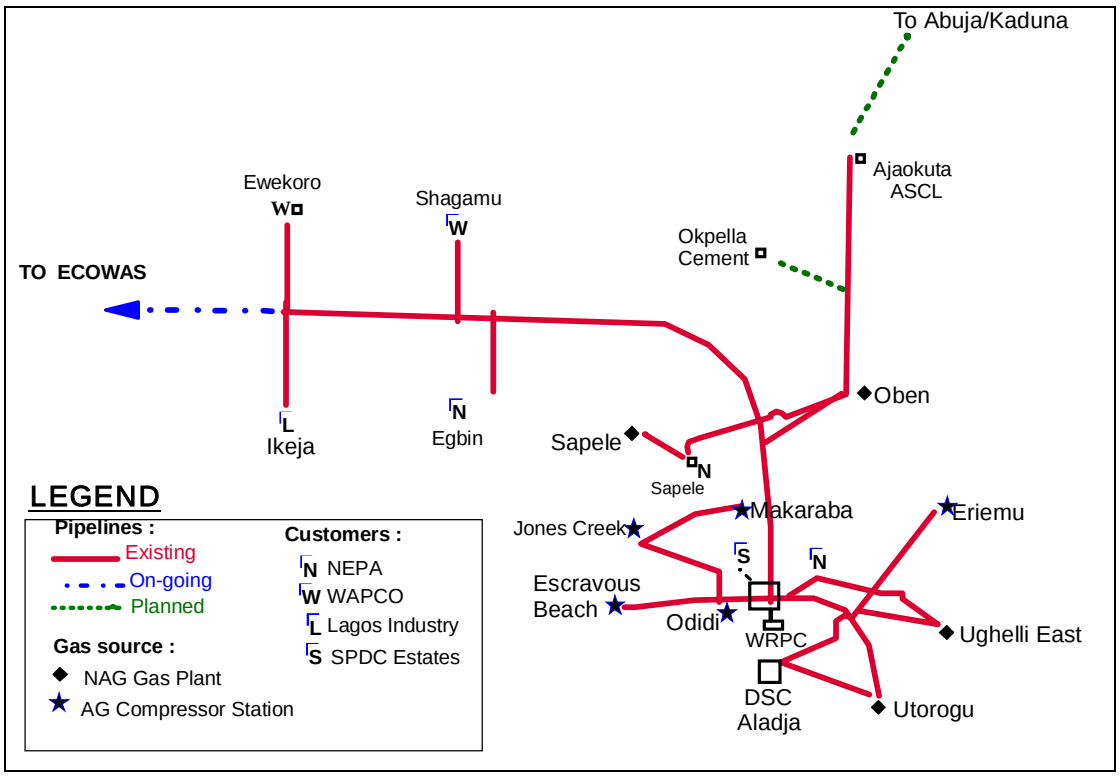
- Sapele - supplying gas to the National Electric Power Authority (NEPA) power station at Ogorode, Sapele
- Aladja - supplying the Ajaokuta Steel plant
- Northern Pipeline system
- Imo River-Aba Industrial system
- Obigbo North-Afam - supplying another NEPA station at Afam

- Alakiri-Onne - supplying gas to the National Fertiliser Company (NAFCON)
- Alakiri-Ikot Abasi - supplying gas to the Aluminium Smelter plant (ALSCON) at Ikot Abasi
- Escravos-Lagos Pipeline- supplying gas to NEPA power plant at Egbin, and spurs to Industrial estates in Lagos

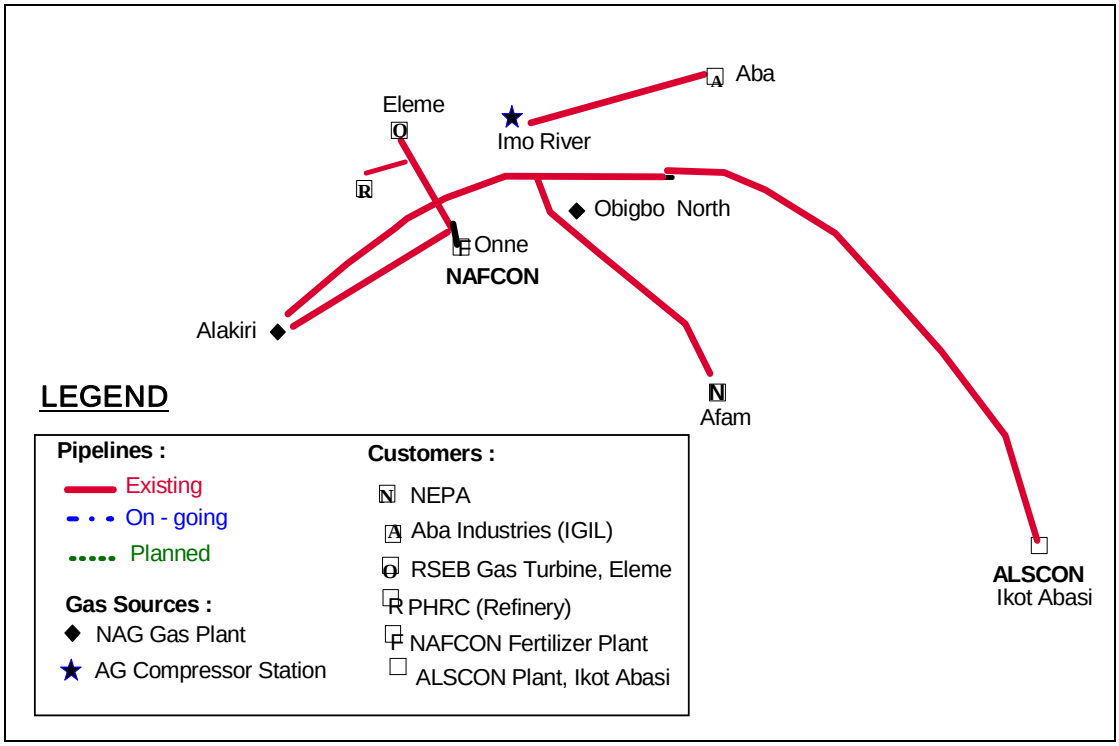
NGC operates a total of 1,100 kilometres of pipelines, ranging from 4" to 36", with a capacity of 2 billion standard cubic feet (scf) of gas per day. The company also has 14 compressor stations, and 13 metering stations. The NGC is also actively developing a number of initiatives including the West Africa Gas Pipeline, being managed by Chevron, the Trans Nigeria Pipeline project, which will provide gas supply to a series of Independent Power Projects being planned throughout the country, and the development of compressed natural gas as an automotive fuel.

The following diagrams provide an overview of these pipeline systems.

NGC: Western Gas Pipeline System



NGC: Eastern Gas Pipelines System



8.3 Physical Audit Procedure

8.3.1 Methodology for physical gas flows

In terms of the scope of this study the focus is on the physical flows of gas between the upstream producers, NGC, large process users such as NLNG, NAFCON and resellers such as Shell Natural Gas and Gaslink. This study does not include the physical flows further downstream into domestic and retail sales to smaller users of gas.

The methodology used to carry out this task has been a combination of the following:

- Information gathered from the industry entities using answers provided in the template spreadsheets.
- Information gathered from interviews with a number of relevant entities on the issue of gas production, supply, marketing and metering in March 2006.
- Information gathered from publicly available sources relating to the gas system and gas marketing in Nigeria.

Data collection templates were sent out to producers, NGC, NNPC-NAPMIS, NNPC-COMD, and other market participants as follows:

- Templates P2-02-AG & P-02-NAG: The purpose of these was to gather physical gas flow data. In particular these focused on the following areas:
    - Gas produced
    - Gas sold to other parties
    - Gas used in production such as lift gas, re-injection, own usage etc.

- Gas flared

8.3.2 The gas flow metering audit

The scope of the metering study focuses on gas metering between the upstream producers and the large downstream gas users / purchasers such as NLNG, NEPA and NGC. It is not within the scope of this audit to include domestic and retail metering.

When large volumes of gas are being measured three key aspects need to be considered:

- The volume of gas physically flowing.
- The heating value of the gas sometimes known as the calorific value.
- The temperature and pressure that the measurement takes place.

The methodology used has been a combination of the following:

- Information gathered from the industry players using answers provided to in a questionnaire. (See Appendix I).
- Information gathered from interviews with a number of relevant entities on the issue of gas metering.
- Information gathered from publicly available sources relating to meter reading in Nigeria.

8.4 Volumetric Analysis and Summaries

In terms of the analysis of the flow data, data was provided from a variety of sources such as the following:

- NNPC-NAPIMS
- NNPC-COMD
- The Gas Producing Companies
- NLNG

A comparison was made of the NNPC-NAPIMS data and the data provided by the Producers. A number of differences were observed between the two sets of data, some of which were minor i.e. only a small percentage difference that could be attributed to rounding etc., however some were significant and warrant further investigation.

The summarised analysis of the data produced by NNPC-NAPIMS has been developed in order to provide an overview of the physical flows of gas and the proportions of that gas that can be allocated to the various categories.

Table 1 – Overview summary of gas production for the period 1999 to 2004

CATERGORY	AG (MMSCF)	NAG (MMSCF)	AG and NAG (MMSCF)	TOTAL (MMSCF)
Gas produced	8,005,862	2,573,939		10,579,800
Gas used as fuel	424,019	11,909		435,928
Gas re-injected			1,922,349	1,922,349
Gas lift			168,928	168,928
Gas to NLNG	519,248	1,340,577		1,859,825
Local Gas Sales	372,404	458,063		830,467
Feedstock gas			230,769	230,769
Transfer to EPCL*			41,091	41,091
Gas flared	4,393,087	770,622		5,163,709

(* EPCL: Eleme Petrochemical Ltd.)

The above table summarises the breakdown between:

- gas used as fuel, re-injected (to pressure the well to increase oil output) or gas lift (assisting in lifting oil by mixing with oil to reduce density)
- gas sold either to NLNL, NGC, feedstock or EPCL
- gas 'wasted' by flaring.

From this it can be seen that, over the period:

- 48% of the gas has been flared (but this is reducing, see next page).
- 17% was consumed by NLNG
- 18% was re-injected

Tables giving a more detailed review of gas production, flaring, and gas lift by company for each of the years 1999 to 2004 is contained in Appendix C.

Summary of gas flaring for the period 1999 – 2004

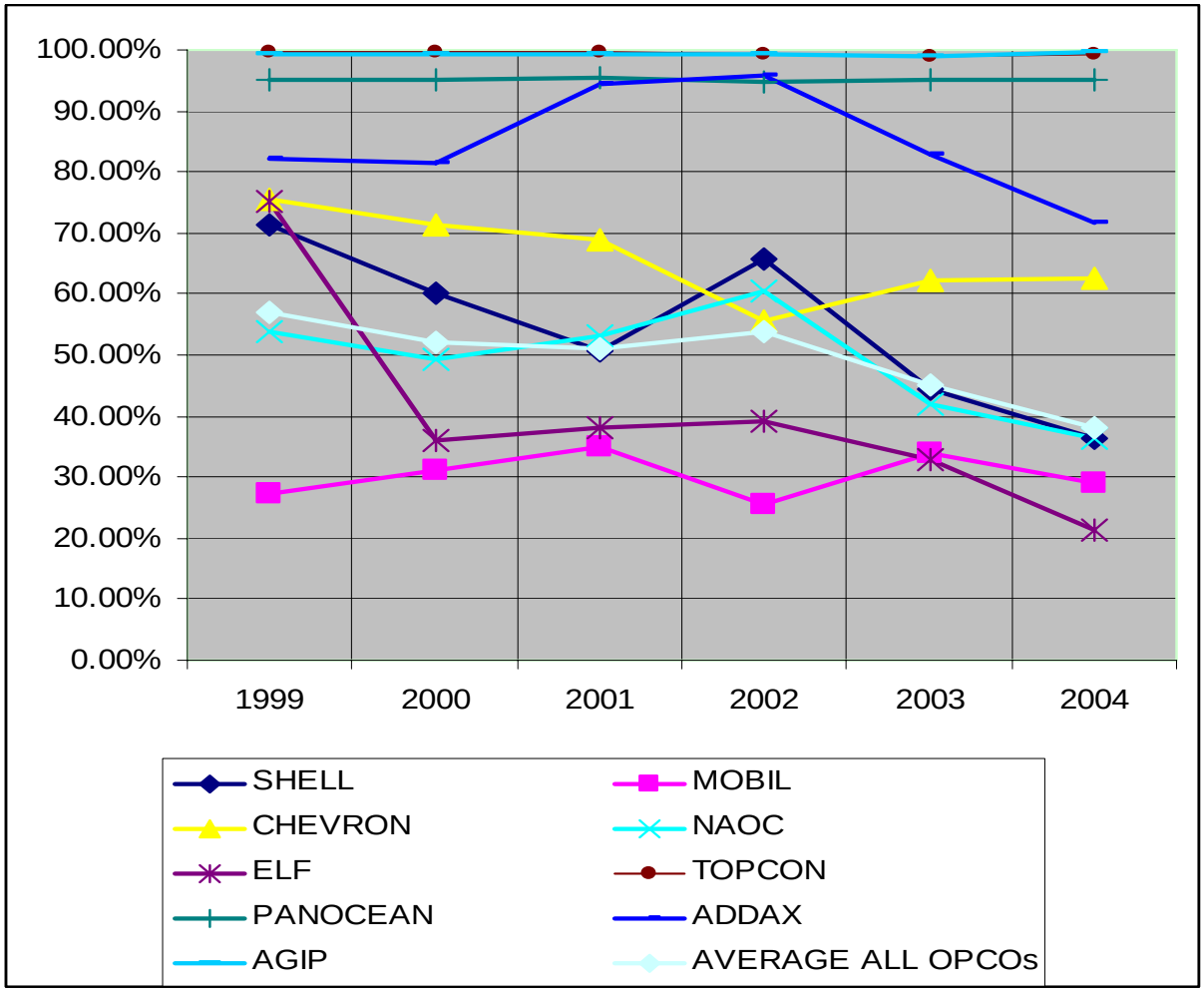
Gas flaring or rather the reduction of gas flaring in Nigeria is a major political, environmental and commercial issue. Initially gas flaring was planned to be reduced to zero by 2004, the data has now been extended to 2008. The following table charts the reduction in the percentage of gas flaring from 1999 to 2004. Whilst it can be seen that a reduction of some 18-19% from 57% to 38% has taken place over a period of six years the ability of Nigeria to further reduce the 38.4% to zero by 2008 must be in doubt. The challenge will be to find markets for the gas either in Nigeria or elsewhere.

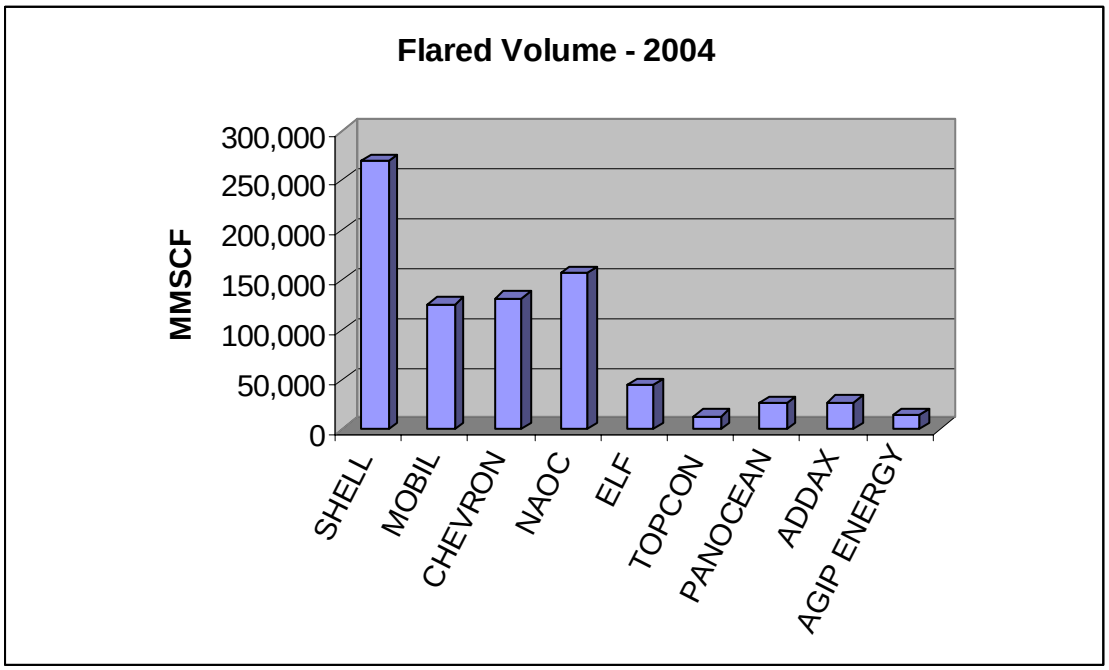
8.4.1 Detailed review of gas flaring for the period 1999 – 2004 by company

The following table is a more detailed analysis of the process of reducing gas flaring during the period 1999 to 2004.

Year	1999	2000	2001	2002	2003	2004	VOL 2004
Company Name	AG&NAG Gas Flared as % of Total Production						(MMSCF)
SHELL	71.16%	59.99%	50.78%	65.84%	44.36%	36.42%	269,130
MOBIL	27.19%	30.96%	34.92%	25.61%	33.99%	29.04%	126,046
CHEVRON	75.39%	71.16%	69.05%	55.55%	62.28%	62.65%	131,587
NAOC	53.78%	49.35%	53.00%	60.38%	41.79%	36.26%	157,360
ELF	75.13%	35.98%	38.12%	39.05%	32.84%	21.33%	44,775
TOPCON	99.58%	99.65%	99.55%	99.37%	99.11%	99.15%	13,564
PANOCEAN	95.16%	95.10%	95.28%	94.75%	95.24%	95.24%	25,968
ADDAX	82.20%	81.48%	94.51%	95.83%	82.76%	71.77%	27,137
AGIP ENERGY	99.22%	99.17%	99.34%	99.18%	99.11%	99.52%	14,195
Annual Average	**56.91%**	**52.12%**	**51.13%**	**53.91%**	**44.99%**	**38.20%**	**809,762**

(Based on data provided by NAPIMS, see Appendix C)





8.5 Technical Assessment Of Gas Metering

The purpose of this section is to provide an overview of current gas metering practice in Nigeria. Areas covered include the following:

- A brief discussion on how gas metering works.
- A review of upstream and downstream infrastructure in relation to gas meter flow metering
- A review of the customer interface.
- A technical and regulatory review of gas metering in Nigeria
- An assessment of the security of these facilities.

The measurement of natural gas can be best categorised into two basic areas:

- Quantity measurement
- Quality measurement

8.5.1 Quantity measurement

Measuring the quantity of natural gas such as the feedstock gas provided from the Joint Venture operators upstream and the measurement of the gas at downstream consumption points such as NLNG are fundamentally the same, with some minor differences that shall be highlighted later on in this report. In terms of measuring the quantity of gas flowing the following is required:

- Flow metering.
- Temperature measurement.
- Pressure monitoring.

There are currently three main meter types used for this type of metering depending upon the volumes of gas being measured, the pressure of that gas and whether the gas measurement is for operational or fiscal purposes.

Orifice Plate Meters

These work on the basis that the 'Orifice plate' provides a known constriction in the pipeline and in order for the gas to pass through this restriction a pressure differential is set up either side of the orifice plate. On the basis that the size of the orifice plate diameter is accurately known, the pressure differential can be easily and accurately measured, which when related together using a mathematical equation based on Bernoulli's equation, one is able to calculate the flow of gas.

(NB: It should be noted that orifice plate metering has been used for many years to calculate gas flows for fiscal purposes, although a fairly long pipe run up to and beyond the orifice plate meter itself is needed, around 40-60 pipe diameters to limit turbulent flow since the meters are more accurate with laminar flow.)

In terms of accuracy orifice plate meters can be accurate between 0.5% to about 3.0% depending on the flow rates, quality of the orifice plate and how recently it was calibrated. The main problem is pitting of the orifice plate from regular wear and tear, which can alter its dimensions and the original calibration.

Ultrasonic Meters

A more recent innovation in the last 10 to 15 years has been the introduction of ultrasonic meters. These can also be used for fiscal purposes and work by firing ultrasonic waves from a transmitter to a receiver both upstream and downstream, to be received both upstream and downstream. Since the speed of these ultrasonic waves is known in any fluid such as natural gas, any variation in its speed of transmission will be a function of the flow of the gas.

In the main ultrasonic meters are more accurate than orifice plate meters, cheaper to maintain and more accurate. Typically they can measure gas flows to less than 0.5% and also less space to operate in. Because they need to know the quality of the fluid they are measuring, changing fluid properties such as a multi-phase pipeline would not work well with an ultrasonic meter, however only minor changes would be expected in the quality of the gas, this is unlikely to be a problem.

Turbine Meters

Turbine flow meters have sometimes been used to measure the flow of gas. In simple terms a turbine meter can be a fan or turbine suspended in the gas flow inside the pipeline, so that the faster the gas flows the faster the turbine spins, and gas flow is measured. Turbine meters are often used for flow monitoring of pipeline systems and have improved considerably in accuracy in recent years.

Metering of gas sales to local industry, refineries, and LNG plant is normally carried out by Orifice Plate type differential pressure meters, using traditional plan-i-metered charts (or modern electronic versions) that give current delivery rates and total volumes over 24 hour or other periods.

At these internal sales points there is also the issue of the condensate or light crude that is stripped from the gas. This may be re-injected into the suppliers' trunk line or sold on to a third party.

Temperature measurement

Just like in crude oil or other petroleum product the temperature determined is used to calculate the standard volume of gas. This is because of 'Boyles Law' which states the following:

- PV/T is a constant.
- So that (P(1) x V(1)) / T(1) = (P(2) x P(2)) / T (2)

Simply put what this means is that if gas is going to be accurately measured for fiscal purposes, then firstly it is important to know its temperature and pressure, and secondly for comparison purposes all measurements need to be converted to a temperature and pressure at an agreed standard, this may vary from jurisdiction to jurisdiction but for the purposes of NEITI all gas flow measurements have been standardized at 15C&1013mb.

Pressure monitoring

As previously mentioned above knowing the pressure of the gas when it is measured is crucial to obtaining an accurate measurement. Also poor accuracy in pressure measurement is one area where errors can creep into gas volume measurement.

8.5.2 Quality issues

For the energy industry it is not just the volume of natural gas flowing through a meter that is important, but also the quantity of energy flowing through the meter. The quantity of energy is determined by the heating value or calorific value (CV) of the gas:

No of BTU's = Volume measured in scf x Calorific value in BTU's/scf

Therefore when a fiscal measurement takes place either there has to be a very strong certainty in the CV of the gas being measured, i.e. the gas being extracted from the field has been checked and the CV is not varying, or some form of automatic sampling system will be required. For example NLNG use an automatic sampler made by Walker.

8.5.3 Review of gas metering infrastructure – upstream

The metering picture in the Nigerian upstream is somewhat mixed. In discussion with upstream oil and gas producers sometimes referred to as the 'Operating Companies (Opcom)' the following points have emerged.

- ***Metering of gas flaring*** - Whilst historically gas meters have not been installed on the flaring streams, many of the producers have installed gas meters on new gas fields where gas is being flared for the last few years, and where possible many companies are installing meters on older plant too.
- ***Estimating of gas flaring*** - Where gas metering has not been installed on flaring stacks an estimate of the volume of gas flared can be and has been made based on the ratio of oil to gas in the field and the flow of oil.

- ***Types of meters used –*** Historically the preferred type of meter particularly for fiscal measurement has been the orifice plate meter, and a number of these types of meters have been used at custody transfer points in the upstream. However with the development of the ultrasonic meter, with its size, cost and low maintenance cost benefits, this is rapidly becoming the meter of choice in the upstream.
- ***Temperature and pressure correction –*** It would appear that for many of the older metering facilities temperature and pressure correction was either not carried out or an estimate of the temperature correction factor was made.
- ***Measurement of calorific value (CV) –*** It would appear that the upstream measurement regime is largely based on estimated CV's rather than real time or regular CV monitoring. Whilst such an approach may have been acceptable when gas was seen as a by-product of oil production, with the growth of the gas industry in Nigeria, increasing sales, and ultimately the development of a liberalized unbundled gas market a more systematic means of measuring CV will be required. (NB: It would appear that some of the larger customers such as NEPA, and NLNG do measure the CV of delivered gas.)

8.5.4 Review of gas metering infrastructure – downstream

The purpose of this section is to examine gas metering downstream, in order to understand how this fits within the context of the Nigerian gas industry a brief overview of downstream gas infrastructure has been provided.

The metering picture in the Nigerian downstream is somewhat mixed. In discussion with DPR, NNPC-COMD, NNPC-NAPIMS, and other downstream entities the following points have emerged:

- ***Types of meters used*** – Metering of gas sales to local industry / refineries /LNG plant is normally carried out by differential pressure meters, using traditional plan-i-metered charts (or modern electronic versions) that give current delivery rates and total volumes over 24 hour or other periods. At these internal sales points there is also the issue of the condensate or light crude that is stripped from the gas. This can happen in two ways. Ideally NGC seeks to keep the gas as clean and free from liquids as possible, through the use of gas filtering, liquids catchers sometimes called 'Slug catchers' and on some occasions the liquids re-injected into the suppliers trunk-line or sold on to a third party***.***
- ***Temperature and pressure correction –*** By the time the gas has travelled through the NGC gas transmission and distribution network via underground pipes the temperature of the delivered gas is usually constant. Nevertheless where large quantities of gas are consumed at large sites such as power stations and other process type temperature and pressure correction does take place.
- ***Measurement of calorific value (CV) –*** In a similar fashion to the upstream measurement regime, the downstream measurement regime is a mixture of estimated CV's and some regular CV monitoring.

8.6 Review of the customer interface

8.6.1 Metering at the Customer interface

In any market, if a sensible financial transaction is going to take place that is manifestly fair and honest, then accurate measurement of the transaction needs to take. This is true

for a bag of apples as it is for Mbtu's of gas. Therefore in terms of accurate gas flow measurement there are really four basic options as shown in the following table. The main points to note are as follows:

- All gas flow measurement will be to a certain accuracy; typically for international best practice this is around +/- 1%.
- If an accurate value of energy flow rather than just physical flow is required, then the calorific value (CV) needs to be measured in real time. This may mean sampling every hour or even every 5 minutes.
- Accurate flow measurement can only take place when the pressure and temperature is regularly sampled in order to correct for temperature and pressure variations.

In an ideal environment all gas measured, for fiscal purposes would be measured as accurately as possible. However within the context of the Nigerian gas industry the actual quality of meter reading is patchy. This stems from the historical culture that gas was a by-product of oil and was really a nuisance that was not worth or necessary to measure. Clearly as the value of gas has been realised the need for good quality fiscal metering at custody transfer points has increased; however a culture of volume rather than energy measurement tends to predominate.

	Temperature and pressure correction	***Real time calorific value measurement***	***Gas flow measurement***	***Comments***
1	Yes – Real time	Yes – Real time	Yes – Real time	**1st Class Fiscal metering** This configuration is the ideal with a very clear view of the energy in Mbtu's being available. This would be best practice.
2	Yes – Real time	No - Est	Yes – Real time	**2nd Class Fiscal metering** This configuration is less accurate as an estimate for the CV of the gas is made. However in many cases the CV of gas withdrawn from gas fields is reasonably constant.
3	No - Est	No - Est	Yes – Real time	**System Flow metering** In this configuration the only real figure one can be sure of is the gas flow figure, any correction for temperature and pressure is an estimate, as is any energy conversion.
4	No - Est	No - Est	No - Est	**Rough estimate** The weakest configuration is one where no measurements are made at all, and an estimate of the flow is made. This may occur on flaring stacks for example.

8.6.2 Metering at the NGC - Producer interface

When gas leaves a particular gas field it is gathered with gas from other gas fields in the locality and ultimately delivered to the NGC gas transmission line at a custody point. In various discussions with NNPC-COMD, NNPC-NAPIMD and DPR it was made clear that at each custody point a meter reading is agreed by all parties and a gas flow certificate issued. Therefore, at least in theory, there should be no discrepancies between the figures used by the Producers, NNPC-COMD, NNPC-NAPIMS and DPR. However in the analysis carried out for the gas marketing report it was clear that errors did exist where they should not.

8.6.3 Metering at the NGC - Customer interface

When gas leaves the NGC transmission for consumption by a large power generation consumer such as NEPA or other large process users, due to the size of the contract, gas flow metering is also an important aspect of the contract since large volumes of gas and correspondingly large amounts of money are involved. The ideal option is option 1 from the above table, however whilst in some cases energy is measured accurately, in many cases it is not for the following reasons:

- The flow meter has not been recently calibrated.
- The calorific value measurement equipment either does not exist or is broken.
- Only volume measurement is available with an estimate of CV, and temperature and pressure correction.

It is worth noting that, with gas prices as low as 15N and non-payment are common, accurate gas flow measurement is almost irrelevant. However once the issues of pricing and non-payment are resolved, accurate gas metering will be very important indeed.

8.6.4 Regulatory and Technical review of gas metering in Nigeria

Regulatory

In the absence of a Gas Law for Nigeria, it would appear that currently there is no formal gas metering regulation or legislation. Typically one would expect to see guidance on the quality of meter reading accuracy and some formal means for local and national governmental agencies to both confirm the accuracy of the meters themselves and the actual readings. Currently no such regulation or guiding legislation exists.

Technical standards

Similarly to the above, currently no locally enforceable technical standards exist within Nigeria. Therefore producers, NGC and customers have responded in a variety of ways. Some have followed internationally agreed standards in terms of the quality of meters used, temperature, pressure correction etc, whereas others have taken a more low cost approach. The former is to be encouraged.

It is also worth noting that some of the large customers, particularly those whose process would be significantly impacted by changes in CV or other gas quality parameters tended to install gas quality measuring equipment as well as volumetric meters. Such an approach would significantly increase the certainty of gas meter reading and should be encouraged.

Calibration and maintenance procedures

The regular calibration and maintenance of gas meters, particularly those used for fiscal purposes, is an important aspect of any gas industry seeking to operate in accordance with internationally agreed good practice. In keeping with the lack of Gas Law and a more formal regulatory framework, there did not appear to be any consistency in the approach to gas metering calibration and maintenance.

The actual process and regularity of the calibration and maintenance of gas meters will to an extent depend on the type of meters being calibrated, and the nature of the environment that the meter resides. Typically one would expect to a programme of regular maintenance that consisted of the following:

- **A monthly site visit -** This would involve a cursory check of the site to ensure that it was operating correctly, and that figures were sensible etc.
- **A quarterly site visit –** This would involve a more extensive period of maintenance where software checks may take place to ensure that flow integration is taking place correctly, also if a standby stream exists, operation of the standby to compare flows etc.
- **A six monthly or annual visit –** This visit would involve a major maintenance of the flow metering, a full calibration test, possible removal and replacement if necessary of the orifice plate.

Certification procedures

In terms of gas flow metering there are two basic certification processes as follows:

- Certification that the meter is accurately calibrated within an agreed tolerance.
- Certification that the said meter reading has been agreed by all parties and effectively signed off.

In discussions with DPR and NNPC-COMD it would appear that currently there is no formal procedure within Nigeria for the certification of fiscal gas meters, which is not unsurprising since in the absence of any Gas Law this would prove difficult to implement.

However there does appear to be a process of agreeing and certifying the actual meter reading at the custody points. Where once a gas meter reading has been agreed between the relevant parties which includes the producers, NGC, NNPC-NAPIMS, NNPC-COMD, DPR, the security agency and possibly the customer that a 'Certificate of Quantity' is issued that then allows the relevant parties to raise and invoice.

As good as this process is, and great store was placed on this process by NNPC-COMD, that the issuance of this 'Certificate of Quantity' proved that meter reading was all OK, however in the absence of formally recognised flow metering procedures etc, it can easily be a case of 'Rubbish in = Rubbish out!'

8.7 Conclusions

In many ways, the Nigerian gas market is still very much in its infancy. Historically gas has been seen as a by-product of oil production as a consequence traits emerged in the gas market as follows:

- Unmetered gas flaring.
- Volume measurement rather than energy measurement.
- Very low, i.e. below cost gas contracts.
- Non-payment of bills etc.

However with the political and environmental pressure to reduce gas flaring a new gas market has begun to emerge, and despite great strides being made in terms of changing the commercial and operational culture nevertheless the old culture of volume measurement or estimation still exists at least in part.

Gas metering in Nigeria is moving in the right direction. There is an increasing recognition that accurate fiscal metering is an important factor in the development of an integrated, robust gas industry. There are, however, a number of shortcomings that do not facilitate this development as follows:

- The lack of any sort of Gas Law and the associated gas measurement and quality regulations has certainly hindered the development of a robust and coherent gas measurement and gas quality policy.
- The lack of gas measurement and gas quality regulations, which results in a lack of coherence in terms of gas flow metering calibration and maintenance, and the approval of either certain types of meters, or adherence to a particular standard.
- The lack of a formal gas regulator.
- From some of the responses to the questionnaires and in discussion with various players, there appeared to be a lack of understanding of some of the key fundamental principles relating to gas flow measurement such as calorific value, and the impact of temperature and pressure variations.

In general there did appear to be a good understanding from all the entities involved of the importance of metering and the need for highly accurate fiscal metering. It is also clear, though, that many entities in the industry have sought to develop gas metering in line with international standards. For example over the last few years a number of producers in the upstream industry had made good progress in fitting meters to flare stacks, and generally improving the quality of metering, similarly large users are also ensuring that good quality metering is installed at the point of consumption, this progress needs to continue for all players in the industry. Some of the maintenance and calibration programmes in place appeared to be quite robust with companies stating that they sought to calibrate their meters at intervals of between 6 and 12 months each year.

8.8 Recommendations

In terms of making recommendations it is noted that in some cases these may already be in the process of being discussed or even implemented, nevertheless for the sake of clarity they have been included in the list.

8.8.1 General recommendations

We recommend the following:

- A general education process in relation to the need for gas metering, its role in a commercial gas industry and how it all works should be encouraged.
- Introduce a new Gas Law[2] covering regulatory, technical and commercial aspects of the Nigerian gas industry.
- Introduce gas measurement and gas quality legislation or regulations that clearly establish the requirement for gas measurement covering the following:

  Metering Standards – This will cover accuracy, type of meters etc.

  A Meter Certification Standard – Certain meters could be approved by the Nigerian regulator, or an international metering standard could be suggested.

  A meter calibration standard – This would clearly set out what the meter owner and operator would be required to do to gain an approval certificate. .

[2] We understand that a draft law is currently under consderation.

A meter reading approval standard – A simplified process needs to be agreed with all the players over exactly what is required to ensure that a fiscal meter reading is approved as accurate.

A dispute resolution procedure – If there is a dispute between parties some form of dispute resolution procedure needs to be available.

A standard for measuring the CV of the gas.

8.8.2 Recommendations for the upstream

The progress already made by some participants in the upstream should be encouraged; the following should be undertaken:

- If gas is going to be flared it should nevertheless be metering accurately. Clearly, there is no economic rationale to install metering on a gas flare stack that is going to be decommissioned before 2008, however it is suggested that if a producer cannot guarantee that flaring will stop on or before 2008, then accurate metering should be installed. There is an obligation to meter gas to flare.
- There needs to be high quality, accurate fiscal metering at the custody transfer points, where either CV is measured using real time sampling, or where the source field CV is constant regular CV sampling say, weekly, monthly is undertaken to confirm this assumption.
- Temperature and pressure correction should be introduced on all fiscal metering points.

8.8.3 Recommendations for the downstream

In addition to our general recommendations, the main points to note are as follows:

- A standard for the quality of customer meter reading should be developed: appropriate international standards should be adopted for the different customer groups.
- The development of a formal policy for the measuring of CV and the charging of customer groups.

9 PROCESS ASSESSMENT – THE ROLE OF AUDITORS

9.1 Introduction

We made inquiries about the audit arrangements already in place in covered entities for the purpose of assessing the extent to which these audits may be relied upon by government has providing protection for the government interest in the oil and gas sector.

For the purpose of this discussion, we addressed the following perspectives of the government interest:

- financial benefit streams, in terms of:
    - Taxation, royalty and gas flaring penalty
- physical benefit streams, in terms of:
    - Hydrocarbon accounting and the hydrocarbon mass balance
    - Unaccounted oil and crude theft
    - allocation of equity crude
    - accounting for production sharing contracts
    - procurement.

We requested information from a selection of auditors[3] of all covered entities and received responses from the auditors of the following entities:

Entity	Statutory auditors
SPDC, SNEPCO	KPMG
Elf Petroleum Nigeria Limited	KPMG
Agip	PricewaterhouseCoopers
Mobil Producing Nigeria Unlimited	PricewaterhouseCoopers
Ocean Energy Nigeria Ltd	KPMG
Statoil	Ernst & Young
Pan Ocean Oil Corporation (Nigeria)	Osindero Oni & Lasebikan
Dubri Oil Company Limited	Akintola Williams Deloitte
NAOC	PricewaterhouseCoopers
AENR	PricewaterhouseCoopers
Nigerian Agip Exploration Limited	PricewaterhouseCoopers
Addax Petroleum Development (Nigeria) Company Limited	Akintola Williams Deloitte
ConocoPhillips (and group companies)	Ernst & Young

[3] Requests refer to the firms which were auditors during the period 1999 – 2004.

9.2 Structure of the audit relationship

To assess the potential effectiveness of the audit as an avenue for protecting Government interest, it is first necessary to consider the structure of the audit relationship, with particular reference to independence.

9.2.1 External statutory audit

The structure of the external audit engagement is governed by statute (companies and Allied matters act 1990).

Auditors of the international oil companies operating in Nigeria were appointed on the basis of referral from the parent company. They confirmed that compliance with applicable institute / professional guidelines on independence and with International Auditing Standards.

Statutory auditors are appointed by the directors are the respective company, with the duty to report to the directors. Auditors view their main responsibility in the context of their relationship with the directors.

Among the responding auditors, some acknowledged the existence of the duty of care to other users of the financial statements, including the government. The scope of this duty was viewed in terms of reliance being placed on the financial statements for the purpose or tax assessment.

External auditors are required to report on the mapping of financial statements to NNPC chart of accounts, in the reports prepared for the JV Operating Committee. In undertaking this reporting responsibility, they are appointed by the directors of the operating company and provide their report to the JV partners, in accordance with the Joint Operating Agreement. NNPC, as a partner, would be entitled to rely on such reports.

9.2.2 Internal audit

The structure of the internal audit function is determined by each company independently and in the light of the companies perceived the internal audit requirements. It is also affected by certain regulatory issues, depending on the jurisdiction within which the company or its holding company are located, which might impose either requirements or recommended practice as to the reporting arrangements for internal audit.

There is a wide variety of arrangements amongst covered entities. In some cases, internal auditors report directly to the internal audit function of the parent company, without any involvement at all of local management. Some internal auditors report to the local board. Some companies do not maintain an internal audit function.

In view of the diversity of arrangements, and particularly of the lack of demonstrable independence of the internal audit function, Government should not expect to place direct reliance on internal audit work. Comfort may however be derived if an entity maintains an internal audit function staffed by qualified professionals: it can reasonably be expected that an internal audit department will contribute to strengthening the control environment within the entity.

9.3 Scope of external audit work

Assuming that other structural issues to get more can be addressed adequately, the Scope of work of the auditors requires consideration. We have reviewed the current work scope in relation to key areas addressed by NEITI. We have also considered the option of possible work extensions targeted to NEITI requirements.

Auditors determine their work scope on the basis of a judgement as to the level of risk in each activity area and an assessment of what is necessary to enable them to report on the entity's statutory financial statements and / or provide special-purpose reports on specified information. We obtain information from auditors of covered entities about the scope of their work in specific areas:

9.3.1 Work on taxation liabilities

Auditors confirmed that they undertake verification work on the computation of taxation liabilities. The depth of this work is unclear, however. Auditors considered that taxation was an area that, by virtue of its size, was material to the financial statements and required attention.

Auditors generally no longer provide taxation advice services to their audit clients, due to independence regulations. There is a relatively small pool of professional firms with understanding and experience of oil and gas taxation and therefore the auditors of one company may provide taxation (and other consultancy) services to other firms within the industry.

9.3.2 Work on hydrocarbon balance

The practice of audit forms in relation to hydrocarbon balance varies. Some firms review available hydrocarbons information whereas others consider that it has no relevance to the statutory audit.

Those firms that review hydrocarbon balance information do so because it informs decisions on amortisation and depletion; it also is relevant to determination of the completeness of accounting for revenue. However, auditors informed us that such information is not always available or complete and its quality is variable.

9.3.3 Work on procurement and project approval process

Auditors place reliance on the formal approval procedures for capital expenditure (ie: Operating, Technical and Management Committees). They consider that if expenditure has been approved through this procedure there is little need for further enquiry into the quantum of expenditure.

9.3.4 Fraud detection

Whilst all auditors consider the risk of fraud, their focus is on whether it may have a material impact on the financial statements. All auditors assessed that the risk of fraud in their respective company audits was low.

An important feature of fraud risk in relation to international companies is that most companies are subject to US SEC filings. Companies have ethical policies specifying code of conduct and procedures to be followed in the event of transgression. Auditors generally assess that companies take this seriously.

Some auditors informed us that they review the risk of management over-ride of the organisation's internal controls. Those that reported this indicated that they considered the risk of override was low.

Auditors informed us that they consider that the risk of fraud in the industry was mainly outside their client's organisations. Potential scenarios related to possibilities to corrupt procurement processes indirectly.

9.3.5 Conclusion on workscope

Auditors' workscope has been defined with the clear objective of expressing an opinion on the financial statements and complying with relevant accounting legislation (which may include foreign legislation, foreign standards and international accounting and auditing standards, depending on the jurisdiction relevant to the parent company).

Although elements of the workscope overlap with the interests of NEITI and the impact on the protection of Government interest, our principal conclusion is that the objectives of the work are too dissimilar and limited in scope to allow Government to rely directly or mainly on that work for assurance that the Government interest is being protected.

We conclude that present IOC auditing arrangements have not been suitably targeted to protection of the Government interest and cannot directly be relied upon for that purpose.

9.4 The way forward

The NEITI process has, for the first time, explicitly linked the physical aspects of hydrocarbons development and production with the financial aspects. This was a groundbreaking initiative. In some ways, the endeavour to bridge the gap between physical and financial mirrors the structure of covered entities which has traditionally placed engineers and accountants in separate parts or the organisation. As a generalization, it could be said that bridging the gap between engineering and financial functions is an important management issue for most organisations.

A key recommendation for strengthening the protection of government interest is to construct reporting frameworks which explicitly linked the two. Further, the traditional monitoring and reporting arrangements in the industry have tended to focus on financial issues. They finding from this audit is that greater emphasis on the physical flows is required. Regardless of any auditing requirement, progress would be made simply by requiring the regular reporting of key physical and physical-financial matters.

Reporting on these matters is already implicit, to some extent, in the annual external audit of the financial statements. It has been seen, however, that the structural and scope limitations on an annual audit may not provide the degree of assurance that government is seeking. By setting out these matters in a separate report, their profile is raised and information quality should be strengthened.

Recommendations on the nature and frequency of such additional reporting have been made elsewhere in this report. At a minimum, those reports should be signed off at board level in the covered entity. Additional assurance may be obtained by seeking a report on that information from an auditor.

Internal auditors' position in their organisation is structured to support the management of the organisation, so internal audit work may be viewed as providing a degree of additional assurance that the organisation's system of internal control is operating satisfactorily. Some smaller organisations do not maintain an internal audit function and it will be unreasonable to require them to establish one if they do not see a cost-benefit justified business reason for doing so. Nevertheless, any additional requirement on the directors to present special reports might beneficially being supported by internal audit work in these areas; it would be for the directors to decide how to approach this.

We propose that the role of external auditors may be developed, with a view to increasing the degree of protection of the government interest. Nigeria might require specific supplementary information to be presented along with the annual financial statements on areas of concern, such as:

- hydrocarbon production data
- quantification of tax and royalty liabilities
- timeliness of tax and royalty payments

We recommend a consultation process to discuss what can be provided within reasonable cost constraints. NSWG should prepare a discussion document, based on this report, setting out desirable additional reports. Discussion should take place within a forum, constructed to include NSWG, the NEITI auditors and representatives from among the accounting firms working in the industry.

The reporting and monitoring philosophy needs to be developed in harmony with future NEITI audit procedures. It is desirable to avoid proliferation of audits and auditors. Depending on the outcome of the forum, NSWG may decide that the statutory auditors should be asked to examine additional statements. The frequency and depth of the examination would need to be determined. If such statements were already subject to reporting by statutory auditors, arguably it should not be necessary for a second firm of auditors to repeat that work every year, but a less frequent review would provide the necessary additional assurance.

These proposals are not mutually exclusive options and indeed it is unlikely that any single change would provide a panacea.

10 PROCESS ASSESSMENT - DOCUMENTARY CONTROL

We have reviewed documentary control procedures aimed at protecting Government interest in hydrocarbon streams. Principally, such controls comprise:

- The activities of DPR in monitoring some aspects of hydrocarbon flows
- The role of NNPC NAPIMS in managing the Government interest in JVs and PSCs
- The role of NNPC COMD in managing the export of Government equity crude.

10.1 Activities of DPR

DPR occupies a potentially pivotal role in the monitoring of hydrocarbon streams. DPR's role may extend, in some respects, to management of the Government interest, in terms of licensing and regulatory activity. Our analysis of DPR's activities (in so far as required by our Terms of Reference) in relation to Licensing is set out in a separate process report.

DPR undertakes fiscalisation work and maintains records of export of crude oil. We have, for the purposes of this audit, brought together the companies and DPR to compare and reconcile their respective records of exports for the period 1999-2004. The finding of the audit has been that, ultimately, there was a good measure of agreement (with a small number of exceptions) between the DPR records and the company records. However, the path to reaching this agreement was difficult and revealed large number of discrepancies between company records and DPR records. In the course of reconciliation, it may be said that the majority (but by no means all) of corrections were required to the initially reported DPR figures. In many cases, it seemed that these related to clerical errors in either the preparation of the data templates for this audit or in the maintenance of the original records. It is perhaps unsurprising that DPR, which has maintained its records in mainly manual form for this period, and relies on a very small number of 'subject experts', should be susceptible to such errors. However, the conclusion to be drawn is that DPR records did not, for that period, provide a reliable information base on export volumes. We understand that DPR has understood the importance of this work and the need for reliable records and has independently embarked on bilateral reconciliation exercises with companies to check the accuracy of 2005 data; this step is to be welcomed.

As the regulator agency for upstream operations, DPR should become the driver of a consolidated hydrocarbon balance which should serve to prove the data that is received from the operators. There is a need for focus in this area.

We consider that DPR potentially has a very important role in protecting Government interest in hydrocarbon flows, but requires adequate resources in order to fulfil this role.

DPR's role in, for example, monitoring gas can be expanded, particularly with the increased appreciation of the importance of gas to Nigeria. DPR may have a role in monitoring more widely than simply terminal fiscalisation: there may be merit in expanding DPR's responsibilities to include monitoring of the entire hydrocarbons development chain, including reserves in the ground, wellhead measurement, flow station monitoring. At present, no single Government entity is undertaking comprehensive monitoring of the exploitation of Nigeria's principal natural resource.

Beyond monitoring, there is the question of management. Are the hydrocarbon resources being developed in the interests of Nigeria? At present, the resources are being developed in the interests of the companies (including NNPC) which in some instances may be different from the interest of Nigeria. A management role may be defined and requires a separate study.

Some aspects of that role are currently being handled within NNPC, such as the management of the OPEC quota. However, it is unclear whether the licensing arrangements and decisions on production are correlated with quota restrictions, for which (where the quota would impose a restriction) an economic model is required to allocate production to those activities which provide the most benefit to Nigeria. This is a role that overlaps between NNPC and DPR. Technical allowable production is the province of DPR but NNPC deals with commercial aspects. Again, more detailed study is required to address these questions.

10.2 The role of NNPC NAPIMS

The role of NAPIMS in managing the in managing the Government interest in JVs and PSCs has been described in the Process Audit, in relation to capital and operating expenditure. Recommendations have been made.

This role does not directly contribute to protection of the Government's interest in hydrocarbon management because NAPIMS has tended not to take a strong position over, for example, crude losses.

If NNPC NAPIMS were to take a more proactive role in promoting management of hydrocarbons from wellhead to terminal, that would be a beneficial development and would contribute to improvement of control.

10.3 The role of NNPC COMD

As managers of the export of Government equity crude, COMD should be in a strong position to contribute to ensuring that Government's interest in the sector, as regards obtaining the correct share of production, is protected. The arithmetic entails division of fiscalised quantities and therefore COMD is dependent on information from DPR as to the aggregate amounts for each JV. The role of DPR has already been discussed.

There is a clear case for improved communication between COMD and DPR. The extent of difficulty experienced in reconciling lifted volumes, between the two organisations' respective records, indicates that this has not been happening in the period 1999-2004.

10.4 Conclusion

We conclude that the documentary control of hydrocarbons, within DPR, has not been strong during the period 1999-2004. Attention to this area within DPR has subsequently been enhanced. DPR is important as a source of information to COMD, yet this communication line seems not to have been very effective in the past.

The issue of hydrocarbons management should be viewed holistically. Government should position itself to first monitor and then manage hydrocarbons development on a wider front than is presently done.

A fundamental review of roles and responsibilities within Government is required. A study should propose rationalisation of institutional structures to provide access to all the

necessary skills and resources to undertake this work. Resource implications must be addressed.

11 TEMPLATES AND MODEL

Templates for undertaking a regular NEITI physical audit are in development. The format of the templates needs to be informed by the experience of the physical audit for 1999-2004. This report contains the findings of the physical audit for that period. Confirmation is required from NSWG regarding the nature and scope of future NEITI audits before the requisite templates can be designed. Some elements covered by the current audit have indicated important weaknesses in controls and procedures for securing the government interest in the oil and gas sector. In the light of this finding, the templates should be designed to elicit the specific information that will be required in future years.

A model for monitoring physical flows is under development. The basic version of the model is designed to capture those flows that are of greatest economic value, and/or can most readily be determined. The basic model should be implementable without a great deal of development and training. On the other hand, the information will be high level. The further development of the model should take into account practical matters such as:

- Who will be the custodian of the model (ie: responsible for collating data)?
- With what frequency and on what timescale will data be collected?
- What arrangements should be put in place for regular provision of data?
- What is the purpose of the model, in terms of outputs and to what use will it be put?
- Consequently, what functionality is required from it?

A discussion is required on these issues, taking into account any feedback from the present report, to enable us to finalise the model.