NEITI Nigeria Extractive Industries Transparency Initiative

Nigeria Extractive Industries Transparency Initiative

Audit of the Period 1999–2004

(Popular version)

Nigeria Extractive Industries Transparency Initiative

Audit of the Period 1999–2004

(Popular version)

Contents

NEITI commissioned this popular summary to make the 1999–2004 audit, which contained lots of data and technical terms, more accessible to the general reader. It hopes that the use of general language has not inadvertently introduced any misrepresentations of what the auditor actually said. If so, NEITI apologises in advance. The full report can be found at www.neiti.ng.org

Executive summary

The report highlights the main points of the audit of Nigeria's oil and gas sector covering the period 1999–2004. The audit, commissioned by the National Stakeholders Working Group and carried out by the Hart Group, was unprecedented for its independence and comprehensiveness.

The audit is available on the internet at www.neiti.org.ng.

The auditor was asked to produce a complete picture of the sector's business over the six years, track the funds the industry generated, and measure them against production of oil and gas. The Hart Group also looked into the processes involved in carrying out the business, touched on relevant laws and regulations, and recommended measures to address the main areas of concern.

The **Financial Audit** mapped financial flows, and their chain of custody, to identify the role and performance of specific players. It compared the amounts oil producers said they paid in Petroleum Profits Tax (PPT), royalties and other revenues, with what the Central Bank of Nigeria (CBN), the government's banker, said it received. It compared this data with notifications from the Federal Inland Revenue Service (FIRS) which is responsible for assessing taxes, and from the Department of Petroleum Resources (DPR), the regulator. Then the auditor sampled some companies' tax returns and royalty statements in depth to verify the calculations, and the assessments of FIRS and DPR.

Despite significant difficulties, CBN's tax and royalty receipts were largely reconciled with producers' payments. Discrepancies totalled less than $16 million, around 0.02% of total flows over the six years.

The audit found that the Accountant General of the Federation (AGF), the owner and manager of federal government accounts with the CBN, was unable to exercise control over information flows or anticipate problems or shortfalls.

The auditor's estimates of some royalty liabilities differed from those of the producers. The companies' computation methods also differed from the DPR's. It was reported that the DPR lacked the skills and technical facilities to regulate efficiently, and the royalty law was declared too vague.

Some companies lacked independent confirmation of the expenses they set against tax, and some expenses may have been over-stated to minimise tax payments. FIRS was not proactive in assessing the companies' tax liabilities, and its record keeping systems were inadequate.

Main recommendations

- **AGF** should exercise greater management and control over financial flows
- **CBN** should establish reporting systems to anticipate financial flows
- Greater use of **IT** systems is needed to improve controls and eliminate inconsistencies. This would also improve transparency by promoting a wider sharing of data
- **DPR** should play a greater role in oil industry regulation
- **FIRS**' capacity to deal with PPT should be strengthened
- **FIRS** and **DPR** should routinely work together and share information; they should investigate the differences in calculation and treatment of taxes and royalties and confirm the amounts due

- The **natural gas industry** is becoming more important in its own right, and requires its own laws and regulator.

The **Physical Audit** mapped the sector's oil and gas and refined product flows. It checked whether the extracted volumes are accurately reported, and that each producer's output data agreed with the numbers used by FIRS and DPR for tax and royalty calculations. It also scrutinised crude exports and volumes allocated to the refineries by Nigerian National Petroleum Corporation (NNPC), the state oil company. It explored the producers' criteria and methods for measuring oil and gas flows and the quality and maintenance of equipment used. The central tool for such purposes was a "mass balance", requested from companies, detailing the volumes of all liquids entering their gathering systems and going to off-take points or export terminals.

The audit found that producers had never been asked to provide a mass balance before. The audit reconciled crude oil export volumes calculated by DPR, the producers and NNPC, but found the information provided on crude production was unreliable. Some companies calculated their mass balances based on crude oil entering and exiting the terminals – providing an accurate picture of exports, but not losses incurred through leakage or theft. Companies measured their oil at different points of the journey from wellhead to terminal with varying degrees of accuracy.

Main recommendations

- **Producers** should be required to produce a hydrocarbon and gross liquids mass balance on a regular basis. This should be used to confirm volumes on which royalties and taxes are based. DPR should oversee the process
- **Metering and measuring** arrangements should be reviewed and updated.

The **Process Audit** examined how key agencies and departments managed five key areas of business, as well as the processes in place, for upstream licensing, crude oil marketing, refining and product imports, and for budgeting, capital and operating expenditures.

The ***licensing*** review explored processes for granting licences and drew lessons from the 2005 upstream bid round. It found that the DPR failed to provide sufficient data on key blocks, and that its model production sharing contract failed to meet best practice and win the industry's confidence. The DPR's bidding criteria, and selective granting of rights of first refusal to selected firms on the eve of bidding, deterred many well capitalised and experienced companies, while its lack of due diligence enabled unsuitable companies to prequalify.

Recommendations

- **Improve** the transparency of the system for granting licenses in general
- **Simplify** bidding parameters
- **DPR** should improve quality and availability of data
- **All participants** should prequalify well in advance of licensing rounds
- **International companies** should be permitted to select their own local partners

The ***crude oil marketing*** review detailed how NNPC's Crude Oil Marketing Department (COMD) priced the government's share of equity crude, and how other companies were contracted to market it. It found that the process for selling crude oil operated generally satisfactorily, but that it was not documented. There were no defined processes for selecting and approving contractors to market the crude, which appear

to depend on discretion at senior levels. Some terms, including pricing options made available to buyers appeared generous. Calson, NNPC's marketing joint venture with international oil trader Vitol, frequently assigned cargoes directly to Vitol, when it should have been marketing the crude itself.

Recommendations

- **Formalise and amend** some of the procedures for the sale of crude oil
- **Review** the relationship between Calson and Vitol.

The ***refining and product imports*** review looked at the way NNPC ran the refineries and managed the oil product import business. It found that refineries worked on average at just 41% of their capacity, forcing the government to import more oil products than would have been required had the refineries operated efficiently. The import process, including tendering, contracting and procurement, fell short of current good practice standards.

Recommendations

- **Review** the process for importing refined products
- **Introduce** a downstream mass balance as a monthly requirement
- **Examine** ways of improving the refineries' performance
- **Formalise** the process for review of gasoline imports

The ***capital and operating expenditure*** processes review looked at budgeting and capital expenditure in the joint ventures operated by international companies to see if value for money was achieved, and how NNPC's upstream management arm, National Petroleum Investment Management Services (NAPIMS), managed the government's interest in the ventures. It found capital investment decisions were based on rigorous analysis and advanced practices at the larger companies. NAPIMS did not have a procedure for allocating investment capital between competing projects and lacked a portfolio management system. There was also the potential for conflict between its roles as joint venture partner on the one hand, and contract manager supervisor on the other.

Recommendations

- **Review and recalibrate** NAPIMS' involvement in the joint venture companies to achieve best value
- **Strengthen** NAPIMS' capacity to manage government upstream investment
- **Rationalise** different funding options for government involvement in upstream operations for optimum cost of capital and value for money
- **Review** the timeliness of the process for approving joint venture operating budgets and capital projects.

Who's Who and What's What

Government

Nigerian National Petroleum Corporation (NNPC) State-owned oil company, whose divisions include:

- **Crude Oil Marketing Department (COMD)** Manages the sale of government equity crude. Responsible for sales data, and for establishing a representative price for tax purposes for different crude oils based on market realisations.
- **National Petroleum Investment Management Services (NAPIMS)** Manages the government's upstream investments in joint ventures. Charged with approving capital expenditures and purchase contracts, and with monitoring operating and financial results from NNPC's joint ventures with international firms and production-sharing contracts. NAPIMS receives management reports and audited accounts from the upstream companies, which positions it for review and audit of Petroleum Profits Tax (PPT) filings.
- **Pipelines and Products Marketing Company (PPMC)** Transports crude to refineries, imports and distributes petroleum products

Department of Petroleum Resources (DPR) Has overall responsibility for regulating the industry. It approves exploration licences, drilling programmes, development and production activity, and capital equipment imports. It also monitors and collects royalties, and compiles production data used in the calculation of PPT. It is part of the Ministry of Petroleum.

Federal Inland Revenue Service (FIRS) The Petroleum and International Tax Department (PITD) of FIRS is responsible for assessing and collecting PPT and other direct taxes from the joint ventures, production-sharing contractors and sole risk operators.

Central Bank of Nigeria (CBN) Nigeria's banker. Not only the depository for royalties, PPT and other direct taxes, it also provides collection information for reconciliation with the tax assessments of FIRS.

Accountant General of the Federation (AGF) Accountant to the federal government and "owner"/manager of federal government accounts with the central bank.

Revenue Mobilisation, Allocation and Fiscal Commission (RMAFC) Constitutionally empowered to monitor revenues and allocate them to federal, state and local governments.

Crude Oil Reconciliation Committee Supposed to perform the actual reconciliation of crude revenues with CBN accounts. Works under Finance Ministry direction and groups high-level representatives from NNPC, FIRS, DPR and the CBN.

Petroleum Products Sales Reconciliation Committee Focuses mainly on the reconciliation of revenues received from petroleum products sales. Also reconciles revenues received in relation to government allocations of crude oil to NNPC for the purpose of meeting domestic petroleum product demand and in this capacity is a relevant agency. It is constituted similarly to the Crude Oil Reconciliation Committee.

Other Nigerian agencies

Niger Delta Development Commission (NDDC) Regional development agency for the oil producing areas. The oil companies pay it 3% of their annual operating budget to invest in development projects.

Private sector

Oil Producers Trade Section (OPTS) A powerful committee within the Lagos Chamber of Commerce and Industry. It acts as a trade association and lobby group, and is dominated by operators of the joint ventures.

Joint ventures

Operator	Government share
Chevron Nigeria Limited	60%
Elf Petroleum Nigeria Limited	60%
Mobil Producing Nigeria Unlimited	60%
Nigerian Agip Oil Company (NAOC)	60%
Panocean Oil Corporation	60%
Shell Petroleum Development Company (SPDC)	55%
Texaco Overseas (Nigeria) Petroleum Company	60%

Companies covered

The companies covered by the financial audit are:

Addax Petroleum
AMNI International Petroleum Development Company
Atlas Petroleum International
Cavendish Petroleum Nigeria
Chevron Oil Company Nigeria
Chevron Texaco
Conoil Producing
Continental Oil and Gas
Dubri Oil Company
Elf Petroleum
Express Petroleum
Moni Pulo Petroleum Development Company
Nigerian Agip Energy & Natural Resources
Nigerian Agip Exploration
Nigeria LNG
Ocean Energy
Panocean
Petrobras
Phillips Oil Company (Nigeria)
Shell Nigeria Exploration and Production Company
Statoil Nigeria

Of these, Cavendish, Ocean Energy, Statoil and Petrobras had no relevant transactions to report.

Chapter 1

Introduction

Oil and gas are Nigeria's most important natural resources. They should be exploited in ways that maximise benefits to the nation – through economic rents and a fair share of the profits – while offering stable and attractive terms for investors.

In 2004, the final year covered by the audit, oil and gas contributed more than 95% of exports, 81% of consolidated government revenues and 37% of gross domestic product (GDP).

During 1999–2004 companies drilled more than 1,000 wells, produced more than 5 billion barrels of oil, and raised production capacity to around 2.5 million barrels per day – some 3% of global output. Oil reserves are now estimated at over 36 billion barrels, and gas in excess of 180 trillion cubic feet.

Ever since the oil industry took root in the 1950s, Nigerians have suspected that the sector has been mismanaged, and that its often fabulous revenues have been used to benefit the country's rulers rather than its citizens. This is evident in the absence of the kind of infrastructure, health and education services that should befit the world's 12th largest oil producer in 2007. Instead, the UN has ranked Nigeria 158th out of 177 countries in its Human Development Index.

Citizens have also long suspected oil companies of not paying their fair share of taxes and royalties. Such suspicions have been fuelled in part by rulers diverting blame for revenue mismanagement. The industry is complex, often arcane for commercial and political reasons, and its revenues tend to be centralised in government hands. Till recently the industry's opacity and government secrecy has blocked the scrutiny that would prove such suspicions right or wrong.

Conflict in the Niger Delta, that has forced companies to suspend production periodically, and oil theft, which has caused many thousands of barrels to go missing, have made it very difficult to measure production accurately.

The oil and gas industry in Nigeria is made up of five main elements:

- Exploration and field development
- Production and marketing of crude oil
- Refining
- Marketing and distribution of refined products
- Retailing

The first two are generally referred to as "upstream" activities, while the other three are commonly termed "downstream".

Each activity faces key risks: upstream licences can be granted to under-capitalised and poorly qualified operators, who would only speculate on, rather than explore and develop, the country's reserves. Production and prices can be under-stated to minimise payments of royalties, and expenditures can be inflated to reduce tax payments. The national oil company, Nigerian National Petroleum Corporation's (NNPC's) arrangements with companies that market the federation's share of crude oil, could be limiting opportunities to maximise the price.

Risks in the downstream include negligence – or even sabotage – of refineries, leading to higher oil product imports, product losses and potentially inflated prices.

This audit explores how companies report their payments and assess oil prices, and how effectively Nigeria's regulator, the Department of Petroleum Resources (DPR), the Federal Inland Revenue Service (FIRS), the responsible tax authority, and other institutions monitor and assess the sector's financial and physical flows.

It raises some serious questions over companies' accounting practices and production calculations, and over the quality of tax assessment and regulation by Nigerian authorities, and exposes mismanagement and opportunities for corruption in refining and products.

Nigeria's oil and gas sector remains opaque and vulnerable to corruption. However, thanks to this audit civil society now has an opportunity to understand the sector and has the tools to scrutinise it, debate the findings in an informed way, ask further questions, and challenge executives and officials over errors, omissions and malpractices.

Such scrutiny would have been unthinkable a decade, or even five years, ago, when NNPC's balance sheet was described as "off-limits" even to those brought in to reform the oil and gas sector.

This 1999–2004 audit – the first of its kind in Nigeria's history and a pioneer in emerging market extractive industry accounting – has been shaped by several forces.

An anti-corruption drive launched by former President Olusegun Obasanjo's government, which set up the Economic and Financial Crimes Commission and the Independent Corrupt Practices Commission, got things started.

The momentum has been underpinned by the international transparency movement, grouping activists from producing and consuming countries who have banded together to demand better governance and accountability in the generation and use of natural resource wealth, through the Extractive Industries Transparency Initiative (EITI). Also critical was the determination of Nigeria's EITI secretariat (NEITI), and the tenacity of Hart, the auditors.

Launched in 2004, the EITI now provides a start-up kit for civil society organisations. It calls on companies to disclose all payments to governments, ranging from signature bonuses for oil blocks to taxes, royalties and revenues from government oil sales. It requires the data to be compared by independent accountants, who identify discrepancies and try to find the missing amounts – a process of matching known as reconciliation.

This approach – calling for verification that reported payments and revenues agree – is a good start. But there is no way of telling whether the amounts are correct without detailed examination of underlying transactions. Both receipts and payments are vulnerable to errors in calculation, manipulation and corruption.

NEITI digs deeper to audit the underlying payments, verify physical production, and review how the key processes are conducted.

The **Financial Audit** maps the financial flows and outlines the chain of custody for finances so that specific agencies can be held accountable. It reconciles company payments with receipts of the government's banker, the Central Bank of Nigeria, and with the records of the FIRS, the department responsible for PPT assessments, and the DPR. Then it samples some companies' tax returns and royalty statements to verify the calculations, and the assessments of FIRS and DPR.

The **Physical Audit** maps the sector's oil and gas and refined product flows. It checks that the extracted volumes are accurately reported, and that each company's reported production tallies with the numbers the government uses for tax and royalty calculations. This takes the audit into some highly technical areas featuring metering, temperature and pressure measurements, as well as the more controversial area of oil theft.

The **Process Audit** examines how key agencies run the business. It explores how the regulator auctions and sells oil blocks, and puts DPR's conduct of the 2005 upstream licensing round under the microscope. It assesses whether NNPC's Crude Oil Marketing Department (COMD) prices the government's share of equity crude accurately, and how and why other companies are contracted to export this crude. The audit also examines NNPC's upstream division, National Petroleum Investment Management

Services (NAPIMS), and how it manages the government's interest in joint ventures, monitors costs and approves projects. It also explores how NNPC runs the refineries, and manages the oil product import business that has become so vital as a result of Nigerian refineries' constant underperformance.

For all its comprehensiveness, the 1999–2004 audit was hampered by major obstacles. Oil companies and government institutions had problems complying with the auditor's requests for information in formats suitable for comparison. This was partly because many of the questions and accuracy standards had never been demanded of them before, partly because they all operated different accounting and record systems, and partly because some players wanted to keep certain aspects of the industry opaque. Others did not take the audit exercise seriously.

This audit consequently has imperfections. It suggests a more accurate picture would have been derived had some companies and government agencies been more forthcoming, and had the sampling approach checking underlying transactions and data been broadened to comprehensive auditing of all the players' accounts.

The audit nonetheless has the capacity to put companies and officials on watch, forcing them to reform the way they report their business, and lifting the veil on industry accounting and practices in an unprecedented way.

"Revenue transparency is only the starting point, albeit a very important one, for a broader campaign to improve governance," NEITI says, adding that "once revenues collected are accurately known and reported, focus can shift to a debate on how well revenues have been used."

The following chapters explain the rationale for each audit, key concerns, the scope and methodology used, and the findings and recommendations. The final chapter sums up the recommendations, and the way forward.

Chapter 2

Financial Audit

Rationale

Financial flows from oil and gas are massive, totalling around $95 billion from 1999–2004. But for all their importance to the economy, the oil sector's finances have been poorly understood. Though some limited audits have been done in the past, the results have never been published in any meaningful way.

Aim and Scope

This financial audit asks some basic questions: Who paid, how much, when and to whom? It also tackles the more complex issue of whether everyone paid and received what was due.

It examines international oil companies' payments of taxes, royalties and gas flaring fines to the government, and seeks to confirm as far as possible that they complied with legislation and the so-called Memorandum of Understanding (MOU), a longstanding agreement with the industry that affects and amends fiscal terms contained in legislation.

Nigerian authorities are scrutinised, to see how they assess such obligations, how they manage, monitor and record payments from international oil firms, and how they communicate financial information to one another.

The government's crude oil finances are also spotlighted, to see how Nigerian National Petroleum Corporation (NNPC) records production and sales data, and finances investments in joint ventures and production-sharing contracts.

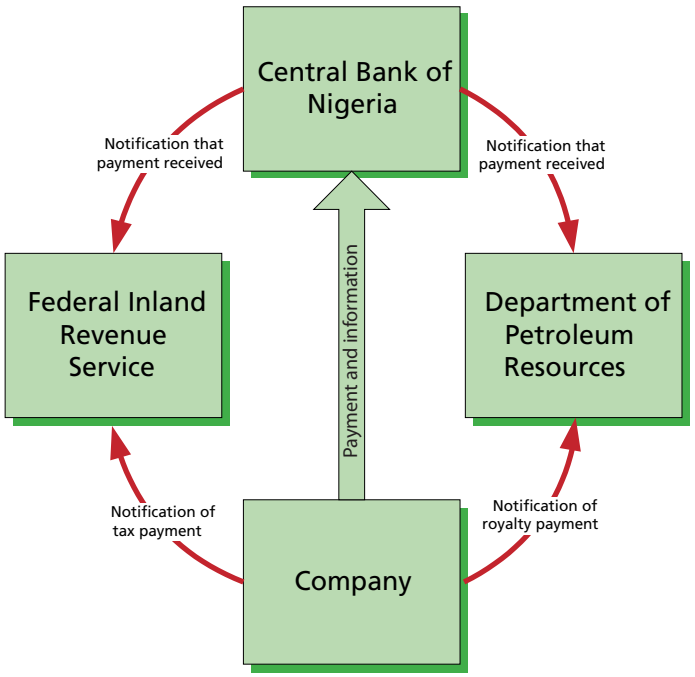
Discrepancies and losses resulting from incorrect or improper reporting are analysed, and improvements in systems and skills for the future are recommended.

At least 25 corporate entities are covered. These include major international oil firms and their affiliates, in their capacities as joint venture and production-sharing operators and non-operators, smaller foreign players and Nigerian firms.

Private oil companies file tax returns and royalty statements with respectively the Federal Inland Revenue Service (FIRS) and the regulator, the Department of Petroleum Resources (DPR). NNPC sells the crude from the government's share of joint venture production. Everyone sends payments to the Central Bank of Nigeria via Federal Reserve accounts in New York, which channel most of the funds to Nigeria's Federation Account, managed by the Accountant General of the Federation.

The Federation Account is jointly owned by the three tiers of government: federal, state and local governments. The Federal Accounts Allocation Committee distributes the revenues to them.

Revenue flow chart



Petroleum Profits Tax (PPT) is governed by the Petroleum Profits Tax Act and its amendments. By definition, it is a tax on profit -- the amount left after operating expenditures and allowances for specific capital outlays are subtracted from income. Rules and laws govern the items that qualify for allowances. Tax officials have to check that a company does not, for example, classify capital outlays as day-to-day costs, or inflate equipment costs to boost capital allowances.

Royalties are normally based on estimated output of oil and gas, price, crude oil quality, and the depth at which an oil field lies. Rates for onshore fields are 20%, while those offshore vary from 4% to 18.5% Any field deeper than 1,000 metres pays no royalties.

In theory, the CBN's receipts should agree with the companies' payment records, and its data should be consistent with the advice sent and received by FIRS and DPR. The AGF should receive copies, to remain informed of the flows they should be managing on the government's behalf.

Methodology

All actors were told to fill in data templates for royalty and PPT payments, and the records of companies, the CBN and the regulator (DPR) were compared. For consistency, all were asked to use a cash-based accounting system, recording financial transactions as and when they occurred.

For more thorough analysis – to determine whether the expenditures claimed against tax in the returns were reasonable – the auditor dipped into the accounts of selected companies, and compared their tax returns with their financial statements. This was intended to provide a sound basis for comparison as the financial statements should already have been approved by another accountant.

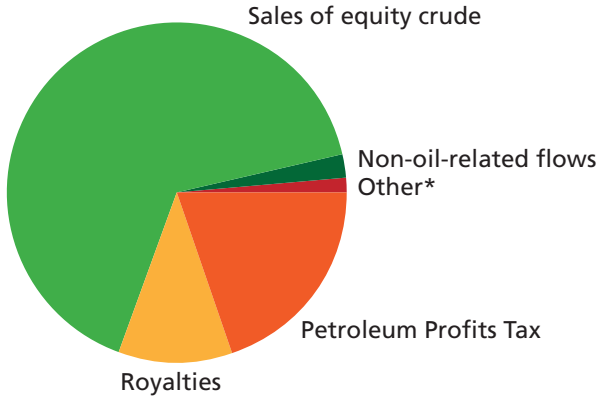
At the same time, the crude oil and gas production volumes filed by companies for tax and royalty purposes were compared with the findings of the physical audit (see Chapter 3).

The Big Picture

The sector's financial flows to the government totalled more than $95 billion from 1999–2004, while the government's flows to the joint ventures by way of cash calls and other items amounted to over $18.2 billion. This left net flows at over $77 billion.

Sales of the government's equity crude and gas accounted for the bulk of the income, at $62.8 billion (see table, page 13). The companies' contribution was dominated by PPT at just under $19 billion, followed by royalties of more than $10.5 billion and signature bonuses of over $485 million, according to the CBN (*see internet version of Financial Audit, aggregated flows table 4.2, p14*).

Share of financial flows



** gas flare penalty, reserves addition bonus, signature bonuses*

Findings

The auditor found some discrepancies between the PPT, royalties and gas flaring penalties the companies declared they had paid and what the central bank said it had received. Ultimately the difference was narrowed to less than $16 million – a marginal 0.02% of total flows, as indicated in the table below.

FIRS' record-keeping was, meanwhile, found to be "incomplete", as it failed to record all company data sent to the CBN. FIRS did not use double entry bookkeeping, or maintain a cash book or ledger.

Summary of differences

The flows reported by CBN have been reconciled to the flows reported by the companies, with the following exceptions:

	Reported by CBN	Reported by companies	Difference	
	US$m	US$m	US$m	%
Petroleum Profits Tax	18,927	18,928	–1	–0.01
Royalty	10,592	10,606	–14	–0.13
Gas flaring penalty	143	143	–1	–0.42
Reserves additional bonus	336	336	0	0.00
Signature bonus	487	487	0	0.00
Non-oil related flows	2,250	2,250	0	0.00
Sale of equity crude and gas	62,804	62,804	0	0.00
Total	**95,539**	**95,555**	**–16**	**–0.02**

NNPC's reported cash calls were reconciled with receipts reported by joint venture operators (*for more tables based on comparisons with central bank data see Financial Audit, pp16–20*).

But when the audit moved away from the CBN to focus on PPT and royalties in more detail, it ran into several problems. The companies' own assessments of production and payments differed from FIRS' records.

Both sides were at fault.

When the audit dug deeper into the computations of selected companies, it found more serious problems:

- The **operating costs** reported by the joint venture companies for PPT differed significantly from the costs set out in their audited financial statements. While some differences would normally be expected due to different accounting rules, the variations were surprisingly large. When asked to account for the differences, only one company, Elf, responded in the required detail. Others provided broad "reconciliations" without adequate explanations for the differences.

- Discrepancies were noted between **fixed asset additions** in the audited financial statements and those in PPT returns, with potentially significant implications for over- or under-claiming of capital allowances. Again, only Elf could account for the differences within the time frame allowed.

- Significant differences were identified between the **intangible drilling and development costs** written off and capitalised in the tax returns and those in the statements. Only Elf and Mobil provided satisfactory reconciliation and explanations, leaving some $639 million of differences unexplained.

Without transparent and verifiable reconciliations, this could represent "excess claims," leading to understatement of chargeable profit in the PPT returns, and by implication underpayment of tax, the auditor warns (*for further details and tables of companies' claims see Financial Audit, pp33–36*).

The auditor concluded that the PPT regime for the period covered amounted to "unregulated self-assessment" by the companies.

Serious anomalies were also noted in the royalty regime. One key concern – explored in more detail in the physical audit – is that some companies, notably Shell, based their royalties on exports, while others base theirs on production. The DPR's assessments

Royalty and PPT assessment issues

	Agency for follow-up	US$m
Royalty assessment issues	DPR	113
PPT assessment issues:		
Operating costs	FIRS	1,802
Intangible drilling costs	FIRS	522
Fixed asset additions	FIRS	–583
Non-associated gas costs	FIRS	499
Excess investment tax allowance	FIRS	156

differed significantly from those of producers because of differences in the way each factored quality, production and price into their calculations.

For example, the key indicators of crude oil quality are gravity, measured by American Petroleum Institute (API) degree, and sweetness, measured by sulphur content. The higher the API number, the lighter the crude; the lower the percentage of sulphur, the sweeter it is.

Nigeria's crudes are produced from many different fields and blended to produce certain grades of oil. The best-known are Forcados Medium and Bonny Light. Nigerian grades have API gravities ranging from 35–45°, ranking them among the lightest and sweetest in the world. Lighter sweeter crudes tend to command higher prices than lower more sulphurous grades. The international companies used an average API gravity for all the crudes feeding into export terminals to calculate the price component of royalties. The DPR, by contrast, factored in the different gravities produced from each oil field.

And while some companies calculated production for royalty purposes on export volumes, the DPR says it took total production estimates from the joint ventures and then divided that number by each company's equity stake to work out royalties.

The audit also describes the royalty regime as unregulated self-assessment. The DPR never transmitted its royalty calculations to the companies, or acted on them. Rather, the companies computed their own assessments, and paid unilaterally.

The DPR's accounting and documentation systems are in any case inadequate to record financial flows, lacking even a cash book or ledgers to record royalty payments.

All the anomalies prompted the Nigerian authorities to review payments, after which they asked companies to hand over a further $500 million. But the auditor could not verify whether this claim was correct as the authorities did not make their parameters and assumptions available.

Causes

Some of the problems stem from unclear legislation.

Tax laws are ambiguous, and companies could be interpreting them opportunistically to cut the government's tax take, using, among other things, the incentives granted under the MOU and on gas for PPT (see box, page 15). Moreover, there are no processes for resolving the different interpretations. The law on royalties is also vague, and does not specify how crude oil volume should be determined.

The government agencies are too weak and poorly resourced to challenge the companies – which have access to world-class tax accountants – and the government hierarchy of authority for overseeing financial flows is not functioning efficiently.

In theory, the AGF is the manager in charge. In practice, he or she is a passive observer, who only gets information – often partial and late – from the central bank, so is unable to anticipate problems and act on them in a timely manner. This is partly because the AGF's position is ambiguous. The constitution gives revenue monitoring power to the Revenue Mobilisation, Allocation and Fiscal Commission (RMAFC). But the RMAFC itself lacks the capacity and the authority, having never got access to NNPC.

Recommendations

The audit recommends practical steps to improve transparency and competence, while stressing that success will depend on more fundamental reforms to Nigeria's energy laws and institutions, as well as investment in new accounting systems, technology and training.

- Initially, it says, FIRS should seek legal advice on how tax laws are being interpreted. This could arm it to take the lead in issuing interpretations of relevant legislation, to guide the industry, tell companies how much tax and royalty should be due, and force them to account for inconsistencies. It should receive training to enable it to work on a par with the oil companies' tax experts to identify potential areas of underpayment.

- Companies' PPT returns should be more transparent, especially when it comes to reconciliation with audited financial statements. The companies should deliver full information on all elements of their returns and reconcile all accounting data with tax data.

- FIRS has in the meantime agreed a standardised format for submissions with the Oil Producers Trade Section (OPTS) of the Lagos Chamber of Commerce. The auditor advises that this template should be sufficiently robust to bring the necessary transparency to implementing the PPT Act.

- The DPR should be more proactive, and fulfil its statutory responsibilities by assessing and monitoring royalty payments to ensure companies pay on time. It should also take legal advice on computing royalties – and engage with producers to agree the basis for royalty assessments – and agree on royalties owed for 1999–2004. The regulator should also improve its information technology and accounting systems to levels commensurate with those used by producing companies.

Institutions, systems and organisation

- The financial hierarchy should be streamlined, starting at the top. The AGF should actively manage and control the oil and gas sector's financial flows as part of broader reforms involving new structures and a wide-ranging review of government information and management systems, covering NNPC's crude oil

Gas

Associated gas is produced with crude oil, while non-associated gas is produced independently of oil. International companies are claiming allowances for both types of gas under PPT, while the auditors believe such claims should be limited to oil-linked associated gas. They may have over-claimed in this way by more than $900 million, the audit found.

The companies counter that section 10 1(b) of the PPT Act provides that all incentives granted in respect of investment in associated gas shall be applicable to investment in non-associated gas. The auditor argues that Section 11d of the act stipulates that expenses incurred exclusively in utilisation of gas should be allowable against gas income, and that such gas profits should be taxed under the less generous Company Income Tax Allowance (CITA).

The companies have also been charging their fines for gas flaring as an expense under PPT, even though the auditor says they should be chargeable against CITA (*see Financial Audit, pp37–39*).

marketing department, the sale of government crude, DPR and royalties, FIRS and tax management, and the CBN.

- The information flow system should be reformed to give the AGF enough data or projections to forecast revenues, and enable him or her to monitor receipts to ensure that financial flows accord with expectations. This calls for new management information systems, with data from upstream companies, FIRS and DPR directly copied to the AGF, indicating how much to expect from the CBN. This would enable the AGF to act when money is not received on time.

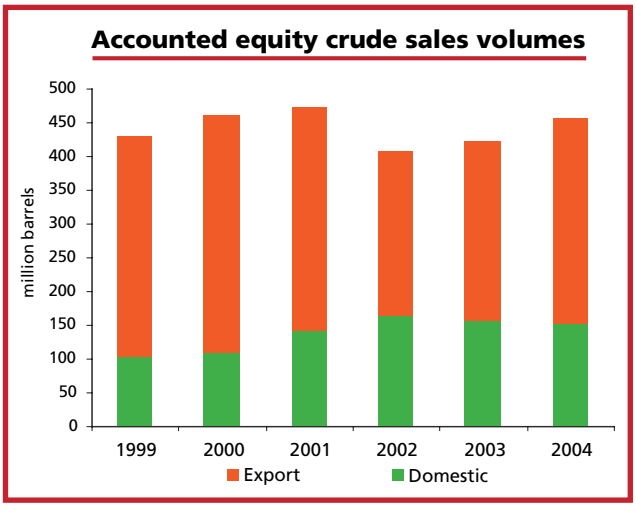
- The CBN's information systems need to be reorganised so that data on oil and gas flows can be extracted more easily.

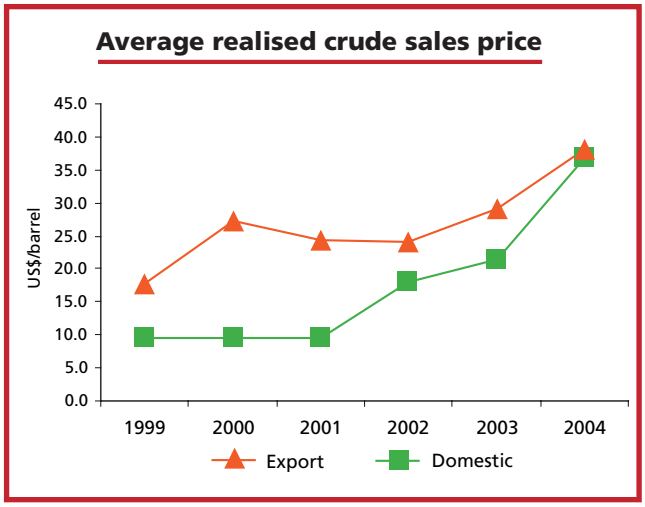
- NNPC should reconcile proceeds from export and domestic crude every month and document the details of reconciliation.

- More generally, the financial audit should be broadened to allow for a more thorough and comprehensive review of royalty assessments than the sampling approach followed in the current audit.

Crude oil sales

All the requested information on crude sales was produced and, with the exception of one difference involving sales to the domestic market, which is still being reconciled, all crude invoiced by COMD appears to have been paid for. Complementary verification of the physical volumes of crude produced and shipped confirm that crude oil liftings were reconciled.





Chapter 3

Physical Audit

Rationale

Nigerians have long wondered how much oil and gas the country really produces every day – and given theft, leaks and disrepair, how much oil disappears en route to export terminals and refineries. How do companies measure their production – and how does the regulator, the Department of Petroleum Resources (DPR), which is responsible for monitoring production, check up on them?

Getting the production volumes as exact as possible is critical. Output data should provide the basis for calculating royalties and Petroleum Profits Tax (PPT), as well as exports, which account for more than 95% of Nigeria's foreign earnings. (It is also essential for calculating how much gas is flared into the atmosphere – one of the keys to measuring pollution – as well as for calculating fines that contribute to revenues.)

The physical audit marks the first attempt to map, track and quantify all Nigeria's oil and gas flows comprehensively – using data provided by government agencies and oil companies. It explores how companies and officials measure and record output, judges the validity of their metering and measuring arrangements, and the accuracy of their data and records. It also seeks to provide a direct basis for comparison with tax and royalty calculations and receipts.

This exercise in marrying and comparing the work of engineers and financiers was fraught with technical challenges. Measuring oil and gas flows is a costly and inexact science at the best of times. Most wells pump a mix of oil, gas and water. The gas and water are separated from the oil at different stages of the journey from well to export terminal or refinery. Technicians measure for quantity and quality, using meters and thermometers that test pressure and temperature at various points. Complicating the calculations, some operators have agreements with third parties to use their pipelines, so the entry and exit of this additional oil at terminals or custody transfer points must be factored into the equation.

Perhaps the most serious challenges of all are posed by the sabotage and oil theft prevalent throughout the Niger Delta, not least because these are unpredictable and difficult to detect.

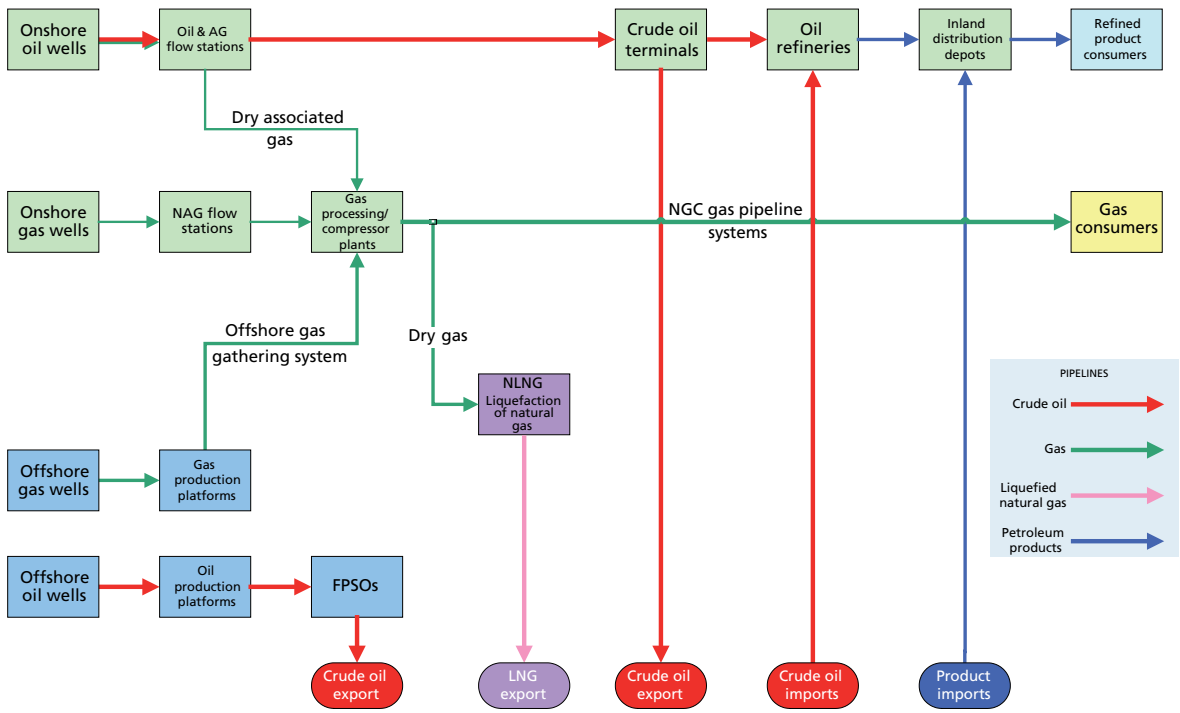
Scope and Methodology

The first task was to map all the flows to the export terminal. As the diagram below shows, the hydrocarbons produced onshore and in shallow waters are pumped from reservoirs to well heads, then along flow lines to flow stations, where gas is extracted if necessary. The remaining oil and water mixture is then pumped along a bigger line – a pipeline. This takes it to a manifold, where it joins up with flows from other pipelines and travels along an even bigger pipeline to an export terminal. There any remaining water is separated and the dry oil stored – before loading on to tankers for export or being sent by pipeline to the Port Harcourt and Warri refineries.

Oil and gas produced deeper offshore travel along flow lines to a permanently moored tanker or floating storage and offloading facility, where it is collected by tankers out at sea. (*For detailed schematics, see Physical Audit, appendix A.*)

All producers were asked to provide a "gross liquid mass balance" for each production stream, for each year, to get a complete picture of all inputs and output to the producers' systems. This includes the volumes of all liquids entering companies' gathering systems from flow stations to offtake points or terminals, including third

Oil and gas production flow chart



party oil. It also includes all liquids leaving the gathering system. The latter should include both the large volumes transferred to refineries and tankers for export, and other volumes lost to theft, leaks, water drained, losses in storage, and changes in stock levels, among other things.

Companies were also asked for estimates of export volumes, for comparison with export data recorded by DPR.

Nigerian National Petroleum Corporation's (NNPC's) crude exports, which include volumes earmarked for direct shipments and barrels redirected for export when refineries aren't functioning, were also scrutinised.

The crude flows to domestic refineries were checked by comparing data from the senders – NNPC's Crude Oil Marketing Department (COMD) and other oil companies – with received volumes reported by the refineries.

Moving on from reconciliation, the auditor went deeper to compare the data on export volumes provided by a sample of joint venture companies with the data they submitted to the Federal Inland Revenue Service (FIRS) for assessing PPT, and to the DPR for royalties.

On the technical front, the auditor also explored the companies' criteria and methods for measuring the oil and gas flows, and took a comprehensive look at the locations, quality and maintenance of their installed meters.

Findings

The bottom line is that Nigeria's true oil production remains a mystery, because some companies base their estimates on the volumes arriving at terminals and offtake points and not on how much was originally pumped from the wells and flow stations.

This approach, which fails to track quantities and mixes at all stages of the journey and extraction processes, leaves no scope for calculating the volumes of crude lost in transit, whether to oil theft, leaks or disrepair (see examples in tables below on Shell's Bonny and Chevron's Escravos, where they could not account for spillages and other losses). There is thus no reliable way of measuring crude production for royalty purposes, in these instances.

Shell Bonny

Million barrels	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 Escravos

Million barrels	1999	2000	2001	2002	2003	2004
Gross volumes from flow station	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	0.0
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

There are several reasons why companies tended to use so-called "net" rather than gross liquids balances. For one, it is technically not possible to measure three-phase (oil, gas and water) flow with any degree of accuracy. Once the gas is removed, the remaining oil-water mix may be measured, but metering systems were not designed for the precision required. Security problems in the Niger Delta have discouraged installation of more complex metering equipment at the flow stations, of which many are located in areas deemed unsafe to send staff for maintenance. Consequently companies site as little processing equipment as possible in the field and concentrate their resources in the terminals, where they have some control over security.

Companies had never before been asked for such information. Indeed they differed over what information should be included in a gross balance, and their submissions varied significantly. It is also worth remembering that more accurate production data

Exports

Million barrels	1999	2000	2001	2002	2003	2004
COMD						
Domestic crude	32.7	72.6	59.3	84.7	113.2	113.9
Direct	334.5	356.6	337.5	240.5	272.0	301.9
Total	**367.2**	**429.2**	**396.8**	**325.2**	**385.2**	**416.6**
Per DPR	**367.2**	**429.2**	**396.8**	**325.2**	**385.3**	**416.7**

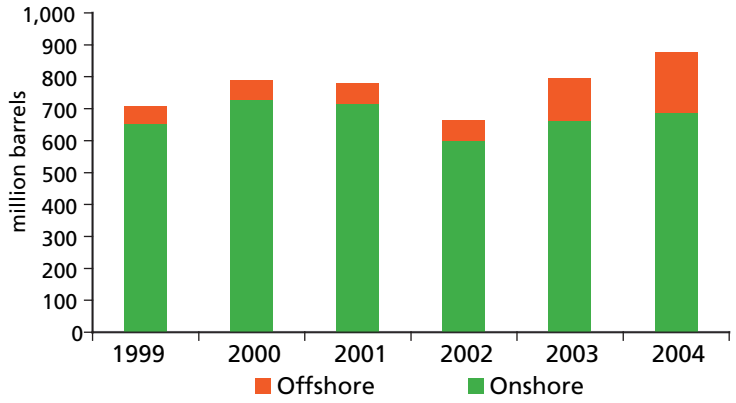
Domestic crude allocation

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

Supply to refineries

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

On and offshore production



would force companies (including the majority shareholder NNPC) to pay royalties on output from which they derive no benefit, such as volumes lost to disrepair or theft.

The audit was consequently forced to do the best it could with what it had: export data mixed with some production data.

On the documentary front, the DPR's export record-keeping appeared unreliable. While it generally tallied absolute volumes, it sometimes lost track of who owned or produced a particular cargo, and the auditor had to reconcile many discrepancies before matching exports reported by companies with those logged by the regulator.

Recommendations

- Arrangements for monitoring the entire production process from wellhead to terminal and refinery should be reviewed and reinforced.

Metering and measuring

The auditor sent out a questionnaire about metering philosophy and practices, and visited several terminals, to observe temperature measurement and tank gauging and crude sampling (*see Physical Audit, appendix D*).

The responses suggest that the equipment used for measuring flows of oil and gas was often inadequate, particularly meters, sampling equipment and temperature and pressure equipment. Companies' records of maintenance work was intermittent, and many meters had not been calibrated (*to learn more about metering, see Process Audit, Appendix H*).

The DPR's measuring guidelines were outdated. For example, it encouraged the use of mercury thermometers – instead of more accurate digital thermometers – for measuring crude temperature in tanks. Other guidelines were inconsistently applied. In this vitally important technical area "there was no culture [in DPR] of striving to follow international best practices," the auditor said.

- The reconciliation process between COMD and the oil companies, and between COMD and the refineries and Nigeria's Pipelines and Products Marketing Company needs to be improved, so that any differences are promptly identified and resolved.

- Companies should put building blocks in place for information systems capable of routine reporting of mass balance data.

- This won't be easy, given that Nigeria's industry does not use standardised definitions or practices. The DPR, National Petroleum Investment Management Services (NAPIMS), National Stakeholder Working Group (NSWG) – and companies should at least make a start and open a dialogue on how to proceed.

- Standards and definitions need to be established for mass balance statements. Mindful that companies differ in their interpretation of "mass balance", the audit collated various companies' interpretations as a first step in the process. "There is a range of issues in definitions and practices to be applied in arriving at the reported mass balance," the audit said. "These, and the timing of implementation, should be agreed on an industry-wide basis."

- At the same time, clearer guidance should be given on points in the flow stream where royalty and PPT should be applied.

- As an interim measure, each operator should analyse its pipeline network to identify the important nodes – gathering points for pipelines – where additional metering could quickly highlight unidentified losses.

- Companies and DPR should meet regularly to identify inconsistencies in their records, and adjust them as early as possible.

- Each company should submit annual statements to both DPR and FIRS, reconciling PPT and royalty self-assessments to annual mass balance and DPR guidelines.

- To reinforce the checks, external auditors should be required to report annually on the hydrocarbon mass balance, though the form would need to be discussed with industry and auditors.

Theft

In the absence of any conclusive data on stolen crude, two companies told the auditors they suspected losses of up to 20,000 barrels per day. One company discovered unauthorised removals of hydrocarbons from its gathering system, and measured wellhead pressure – a very approximate analogue for flows – over several days. This suggested a significant drop in flows just after nightfall and a return to normal as daylight approached. The drop was too sudden and significant to be attributed to thermal change. Shortly after the reduction in flows was identified, the Nigerian navy patrolled the river areas where the unauthorised offtake point was located. During the patrols the flow into the terminal was constant night and day. The company is now reviewing its metering philosophy and investigating means to stem such unaccounted oil loss.

Chapter 4

Process Audit

Section 1: The Petroleum Act and Licensing Policy

Rationale

The 2005 licensing round was significant because it aimed to break with the past and be completely transparent. It sought to raise Nigerian licensing standards to international levels, and dispense with the discretionary practices seen in earlier rounds and individual awards (*for a list of these awards see Process Audit, appendix 4, pp44–48*). It also sought to demonstrate the government's commitment to transparency and the principles of Nigeria's Extractive Industries Transparency Initiative (NEITI) by following models used in Brazil, the UK and Norway.

But it failed to live up to the promises, and was criticised by Nigerian analysts and the oil and gas industry. The auditors took a look at how it was designed and managed, to see what lessons could be learned and applied to future auctions.

Scope and Methodology

The legislation, licensing round rules, prequalification criteria, organisation, data availability and bidding process in 2005 were all reviewed. Rules from countries becoming more transparent, such as Libya, and from countries where transparent licensing is well established, such as the UK, were compared (*for more details see appendices 1, 2 and 3, pp24–35*). Many bidders were also consulted, to gather opinions on what went wrong and how the processes could be improved (*for a list of interviewees and their responses, see appendix 6, p43*).

Findings

The purpose of any licensing round is to attract investment capital and expertise to expand the country's reserves and production base, with an eye to maximising future returns to the treasury. To attract the best candidates, the process needs to inspire confidence and to be seen as transparent and fair.

The 2005 licensing round was plagued by several problems that undermined the interests of Nigeria's oil sector and treasury. Complex and unwieldy bidding criteria deterred well-capitalised and experienced companies, while others were put off by the granting of rights of first refusal on some blocks to selected firms on the eve of the auction. Both problems ran counter to the principles of transparency proclaimed for the round.

Many unsuitable companies prequalified which lacked the technical and financial capacity to execute required work programmes. Many failed to pay their signature bonuses and had to withdraw.

Good data and basic terms are necessary to attract good investors. The Department of Petroleum Resources (DPR), the country's regulator, failed to provide enough information on many of the blocks offered. Some bidders also complained that DPR gave out information selectively.

The DPR's model production sharing contract (PSC) was good in principle, providing a clear outline of fiscal terms. However, it failed to win the industry's confidence. The PSC's "one size fits all" structure failed to reflect the diversity of risks across Nigeria's oil and gas basins, so a company exploring the prolific Niger Delta was offered the same terms as one looking at the less attractive Chad Basin.

The complex bidding criteria made it difficult to bid with accuracy. The four separate weighted criteria were: signature bonus value; work programme; cost oil ceiling – the cap on expenses a company could reclaim against investment in any one year – and local content, or the amount of money and goods to be invested and bought locally.

The DPR got bogged down prequalifying and processing the large number of indigenous companies that entered as local content vehicles (LCVs), under broader plans to involve more Nigerian firms in the oil sector. Too many companies prequalified and many were unsuitable: "Few, if any, LCVs had the financial capability to fund their share of operations in the Deep Offshore or the mature Niger Delta areas," the auditor said.

It is still unclear how so many ill-suited companies managed to prequalify, given their opaque ownership and finances. The implication is that the DPR was negligent in due diligence, partly because it was swamped by sheer numbers, and partly perhaps because of discretionary political intervention on behalf of these companies' owners.

Swamped by the huge number of companies lobbying for a share, the DPR assigned groups of players to split the 10% assigned for the originally intended single LCV per block. It engineered "forced marriages" between groups of LCVs and main bidders. This drove away some of the serious big bidders, and also alienated those indigenous companies who had money, plus geological and commercial expertise.

Recommendations

A mix of measures is needed to improve transparency and strengthen processes in future licensing rounds:

- DPR should make more information available on each block to all candidates equally, and upgrade the quality of the data bank on the blocks by buying in seismic data from third parties. This increase in transparency would lessen the risk that new entrants are put at a disadvantage to established players.

- The regulator should require all operators, non-operators and LCVs to prequalify for the bidding round in advance, to avoid disruption during the round itself. The regulator should make the documents of prequalified companies available to operators, which should be given 60 to 90 days to perform due diligence on LCVs before the formal opening of a bid round.

- Just as important, the regulator should toughen prequalification criteria. **"[T]o prevent shell companies, companies which otherwise lack financial substance, and companies where controlling shareholders cannot be identified, from submitting applications,"** the audit said, adding that no application for prequalification should be accepted from companies "that are incapable of providing certain minimum corporate and financial information".

- The DPR could emulate Libya, whose last licensing round required bidders to provide two years of audited accounts, and the UK, where applicants are required to provide profit and loss forecasts for five years ahead as evidence of their financial and commercial strength, as well as their latest annual report and accounts.

- Local LCVs should give specific undertakings on their ability to finance their participating interest in full. Companies could post bid bonds or bank drafts with their bids totalling up to 50% of the value of the signature bonus. Any winner who fails to pay its signature bonus on time would forfeit the bond and lose the rights to negotiate a PSC.

- Bidding parameters should be simplified and reduced to a market signature bonus and local content, to boost transparency in the bid round. The regulator could also consult with companies in advance on adapting PSCs to reflect geological risk.

- The Petroleum Act, which is almost 40 years old, needs to be updated to reflect the current more complex environment. Such updates should cover rights relating to gas, as well as model production sharing contracts, licensing, and competitive bidding rounds.

Section 2: Crude Oil Marketing

Rationale

The success of Nigeria's crude marketing strategies is central to maximizing the revenues on which the government relies. Some 75% of Nigeria's production comes from Nigerian National Petroleum Corporation's (NNPC's) joint ventures with partners, and this is sold by the Crude Oil Marketing Department (COMD).

Scope and Methodology

The marketing and sales processes were explored, to see whether NNPC was operating according to rules and procedures, and to assess the risks involved. It includes suggestions on ways to improve performance and transparency.

Interviews were conducted with key personnel, including COMD's group general manager, Aminu Baba-Kusa, who reports directly to NNPC's group managing director. Existing procedures were tested, and these included checking documentation on randomly selected sales by NNPC. A key strategic issue was whether NNPC could make more money on sales without imposing undue risks on its currently reliable crude lifting arrangements.

Marketing Process

COMD markets and sells the government's share of equity crude to both local and international markets. A portion of the crude is sold to NNPC's Pipeline and Products Marketing Company (PPMC) for Nigerian refineries, but the bulk is sold through term "lifting" contracts to international traders and refiners. "Lifting" is industry jargon, and simply means moving the crude from storage tanks on to tankers.

Some NNPC cargoes are also sold on term contracts to Calson (Bermuda) Ltd, an NNPC subsidiary held 51% by NNPC and 49% by European trader Vitol, and to NNPC subsidiary Duke Oil.

A handful of cargoes were also sold in the period under review to other countries through "government-to-government" deals.

NNPC opts to sell on a term basis. This means buyers – usually traders – have contracts to lift specific volumes of oil over an agreed period. This makes it a more predictable strategy than sales on the spot market, which involve individual deals for immediate delivery of oil.

Although the term contracts were renewed annually after 1999, by 2004 they had in practice become "rolling evergreen contracts". NNPC sells its crude to term customers on a free on board (f.o.b.) basis, which means ownership of the crude and the risk is transferred immediately to the buyer upon loading. Where possible, NNPC avoids selling on a cost, insurance and freight (c.i.f.) basis, which includes shipping – a method favoured by the government of Saudi Arabia, the world's biggest oil producer, which has its own shipping fleet.

Term contracts awarded by NNPC are weighted heavily in its own favour because it can supply customers with any grade of oil and any quantity it wants. Term buyers

tend to cope with this by swapping or trading cargoes with one another.

The reliability of term lifters is critical because NNPC must be able to move oil out of the terminals. If a cargo is not lifted on time, storage tanks at terminals can become full, which means oil fields have to be shut temporarily, or other terminal partners have to lift more crude. NNPC has, historically, had a reliable set of term contract holders.

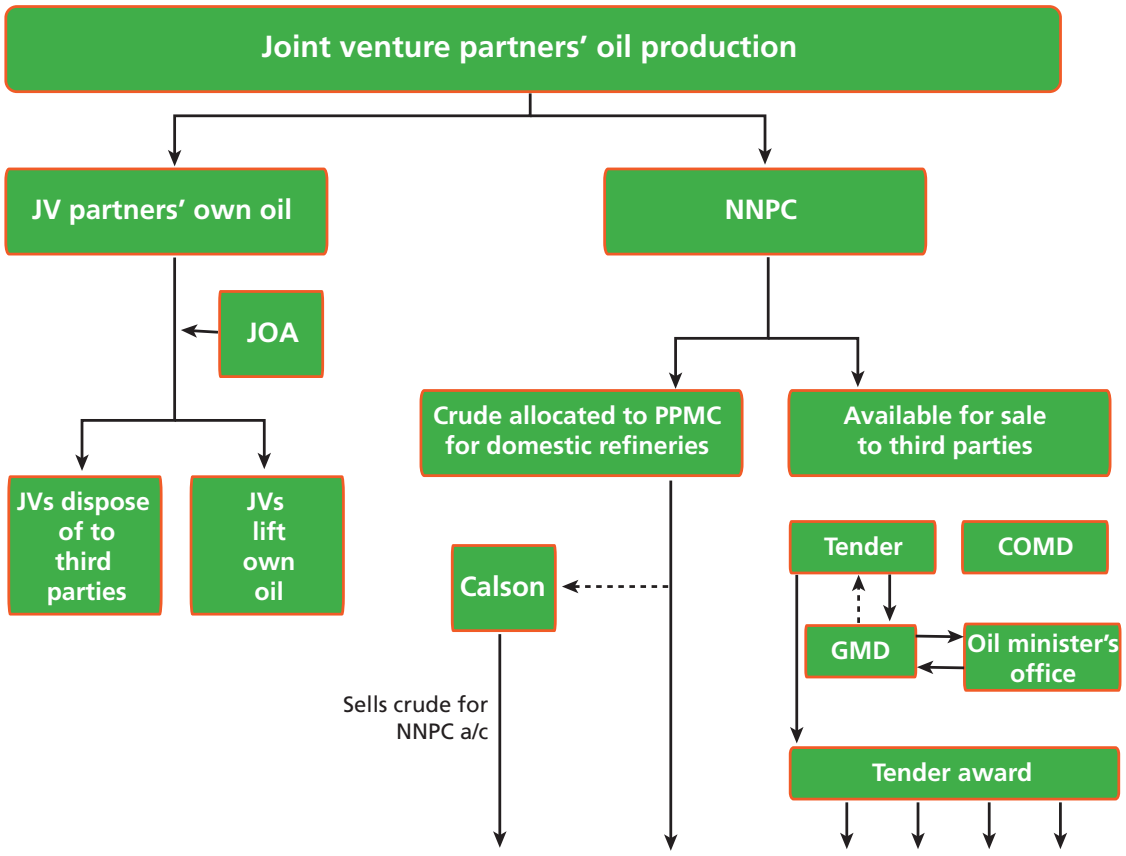
Term customers pay the same official selling price (OSP) in any given month. The OSP fixes the premium or discount of different grades of Nigerian oil to dated Brent, the benchmark off which a lot of the world's oil is priced. The OSP is fixed for the month, but the price of dated Brent fluctuates daily on the global market.

The OSPs are set after COMD's sales and marketing department has researched market conditions. Intelligence gathering entails talking to traders, including the term lifters, refiners, joint venture partners and established media pricing agencies. COMD's recommendations must be approved by the group executive director of the exploration and production directorate, and by the group managing director of NNPC, before they can be published.

Nigeria is one of the few countries that also offers buyers the choice of paying a fee to secure deferred or advanced pricing. These option fees are stipulated by NNPC each month along with the OSPs. The options give buyers a greater number of days in which benchmark dated Brent pricing can be determined, allowing them to take advantage of oil market conditions.

The normal prompt pricing period in Nigeria is five consecutive published quotations of dated Brent after a ship's captain signs a bill of lading to confirm an oil cargo has been loaded. Deferred pricing allows for five consecutive quotes starting six days after

Contractual flow of equity crude through NNPC



the bill of lading is signed. The advanced option spans five consecutive quotes before the bill of lading is signed.

Proceeds from sales are deposited with the CBN.

Main Findings

Crude marketing operates in a largely satisfactory way. But there is some leeway as established procedures are not documented. For example, there is no defined process to decide who can lift government crude. Transparency is lacking as to how term contract holders are chosen, and COMD did not provide auditors with a complete list of contract holders.

Senior managers at NNPC have wide discretionary powers, though these do not appear to have been abused in the period under review. The choice of term buyers is taken at higher levels than COMD, implying NNPC's group managing director and the presidency. Decision making is particularly opaque at these levels.

COMD has formulated its own procedure for recommending an OSP, but it has not been written down or authorised in writing by senior management.

Pricing options available to lifters are generous and probably come at a cost to NNPC. Since a buyer can delay his choice of pricing option until close to the loading date, his selection will almost guarantee a financial benefit. There is no written procedure as to how officials formulate their view on the oil market, and there is a lack of record-keeping on market intelligence gained before the OSP is set. COMD officials say the premiums set for pricing options are based on their analysis of the market's structure – whether prices are in contango (when prompt prices are cheaper than those further out) or in backwardation (when prompt prices are the most expensive). But no evidence was found that the option fees were calculated by NNPC according to a set methodology.

Cargoes allocated to Calson are frequently passed to Vitol due to a lack of financial capacity within Calson. Calson's role is meant to be threefold – to lift normal supplies of Nigerian government crude through its term contract; to lift and sell prompt crude that PPMC cannot use due to a problem at a Nigerian refinery; and to buy petroleum products for Nigeria when there are domestic shortages. In practice, Calson does not always have the capacity to fulfil these roles, as NNPC could lack the capital and credit required of the joint venture, as well as specialist manpower.

The audit randomly selected a number of shipments from the July 2004 lifting programme on which to request all relevant paperwork from NNPC. The document trail was followed all the way to final payments to NNPC's account at the central bank.

Generally, no anomalies were found, but $7.8 million was missing in payments from a cargo lifted by Duke Oil. NEITI was told this was because a Nigerian company, Pan Ocean, supplied part of the Duke cargo because it owed money to NNPC. But none of this was documented, and NEITI recommends that this be further investigated.

Key Recommendations

- Procedures governing the sale of equity crude, including the setting of OSPs, need to be reviewed and improved. Methodologies need to be written out and authorised at a senior level. The NNPC standard sales contract and pricing procedure should be made available on the internet.

- The need to give buyers valuable advanced or deferred pricing options is unclear. At the very least, a robust rationale for the option value should be made available. If pricing options continue, a specific methodology should be used to ensure better returns for NNPC.

- For the sake of transparency, the qualifications needed to apply for a lifting contract should be publicised more clearly. And the list of approved lifters should be published. Criteria for allowing concessionary, or extended, settlement terms for some traders also need to be disclosed.

- The relationship between Calson and Vitol – which is also an "arms-length" term contract holder with NNPC – should be reviewed due to a potential conflict of interest. Commercially sensitive information given to Calson, such as advance notice of OSPs, could find its way to Vitol.

- The standard NNPC sales contract should be reviewed and updated because some clauses are outdated.

- The independence of COMD, the seller of crude, from PPMC, the buyer, should be enhanced to ensure the best deal for the federal government. Record keeping of transactions between the two business units of NNPC has been less rigorous than if the two were wholly independent. But the audit did not find any loss to the government as a result of current arrangements.

- There should be a review to find out whether a change from a free on board (fob) to a cost, insurance and freight (cif) method of selling would gain the government more revenue. A switch would lead to higher overhead costs as cif sales need extra staff with expertise in shipping, chartering and risk management, as well as offices in different countries. Furthermore, the bulk of Nigerian crude ends up in the United States, which could make NNPC's profits on a sale liable to US taxation.

Section 3: Refining and Product Imports

Rationale

Nigeria's refining, or downstream, sector is the Cinderella of the industry. The country's four refineries have underperformed for decades, forcing the government to import oil products such as gasoline, kerosene and diesel at vast cost, and in a reputedly chaotic manner – evident in port congestion, late deliveries and occasional product shortages.

Aim and Scope

The audit reviewed the volumes of crude supplied to the refineries, how they were measured and the refineries' performance. It also explored the system of product supply, the reasons for importing product, the volumes imported and costs involved, and supplies to the domestic market. Its recommendations include ways to manage product imports more effectively, especially in the tendering and decision-making area.

Methodology

Relevant NNPC departments and representatives from downstream oil companies were asked in May 2005 to complete templates with data to enable consultants to assemble a full picture of the downstream industry. Data gathered included information on volumes and prices paid for imported products in the six years from 1999–2004. Records supplied by the DPR were also used to review product volumes imported by independent marketers. Many NNPC documents were lost in a fire and officials had to gather information again using different documentation.

Meetings were held with senior NNPC executives to establish the management controls in place. Consultants visited the refineries and key terminals to establish the procedures used. Interviews were conducted in June and July 2005 with PPMC and DPR to establish the process of importing products, both by PPMC and independent marketers.

Further meetings were held with DPR and PPMC in Abuja in March and May 2006 to review licensing arrangements to import product, import and tendering procedures and other data.

Downstream Overview

Crude oil is pumped from terminals into a tanker for export. Some oil is also pumped to domestic refineries, where it is turned into oil products. Most Nigerian crude is sweet, or low in sulphur, but small amounts of sour, more sulphurous, crude are imported for use in the Kaduna refinery, in north-central Nigeria, to produce lubricant oils.

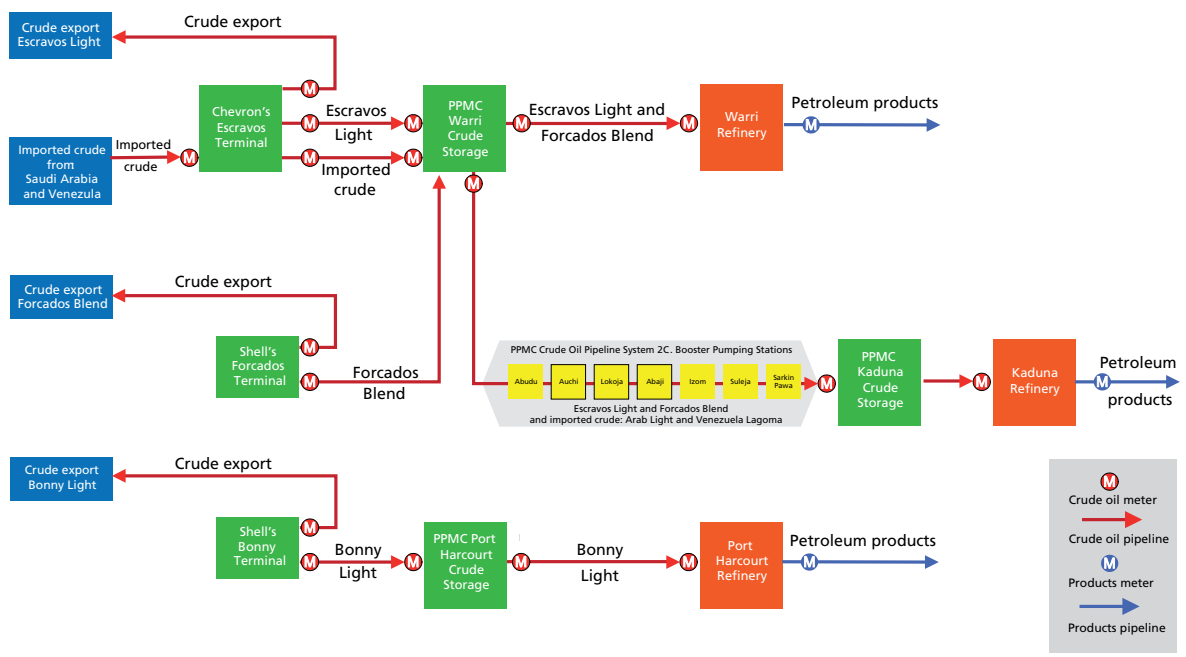
Nigeria has four refineries – two in Port Harcourt in the southeastern part of the Niger Delta, one at Warri in the southwestern part of the delta and one in Kaduna. Kaduna lies far inland from the delta terminals, so all crude supplies have to be pumped through a long pipeline (*see appendix A for a full size schematic and geographic map of terminal and refinery locations*).

The two Port Harcourt refineries have a combined capacity of 210,000 barrels per day (b/d) and are supplied with crude from the Shell-operated Bonny terminal. Warri has a design capacity of 125,000 b/d and is supplied with crude from Shell's Forcados and Chevron's Escravos terminals. The 110,000 b/d Kaduna refinery takes some domestic crude and some sour crude from Saudi Arabia, Kuwait and Venezuela.

The refineries receive equity crude from NNPC's share of upstream production. NNPC buys the crude from the government. The allocation has since March 2001 been set at 445,000 b/d – the full design capacity of the four refineries. When the refineries cannot refine the allocated crude – a common problem because of pipeline sabotage, maintenance problems and underperforming equipment – NNPC exports it. PPMC imports refined product when the refineries do not produce enough to meet domestic demand.

Crude oil supply to refineries

Terminals to refineries storage and pipeline system



A summary of the volumes of primary products, PMS (gasoline), DPK (kerosene) and AGO (diesel oil) produced by each refinery from 1999–2004 is available (*see Process Audit, Refineries, p30*). But Kaduna production for 1999 is being queried with NNPC, since it appears to have averaged 150% of the refinery's design capacity.

The government subsidises the price of PMS, and it is imported by PPMC. Prices of diesel oil were deregulated in mid-2004 and it is imported by independent marketers.

The supply and distribution unit of NNPC's Commercial Department produces a demand forecast every quarter based on expected refinery output, existing stocks inside Nigeria and stocks on board vessels yet to discharge, and expected national demand. This forecast is sent to PPMC's commercial general manager, who must confirm the accuracy of the forecast. It then has to be approved by NNPC's group managing director, before the issue of public tenders to supply products.

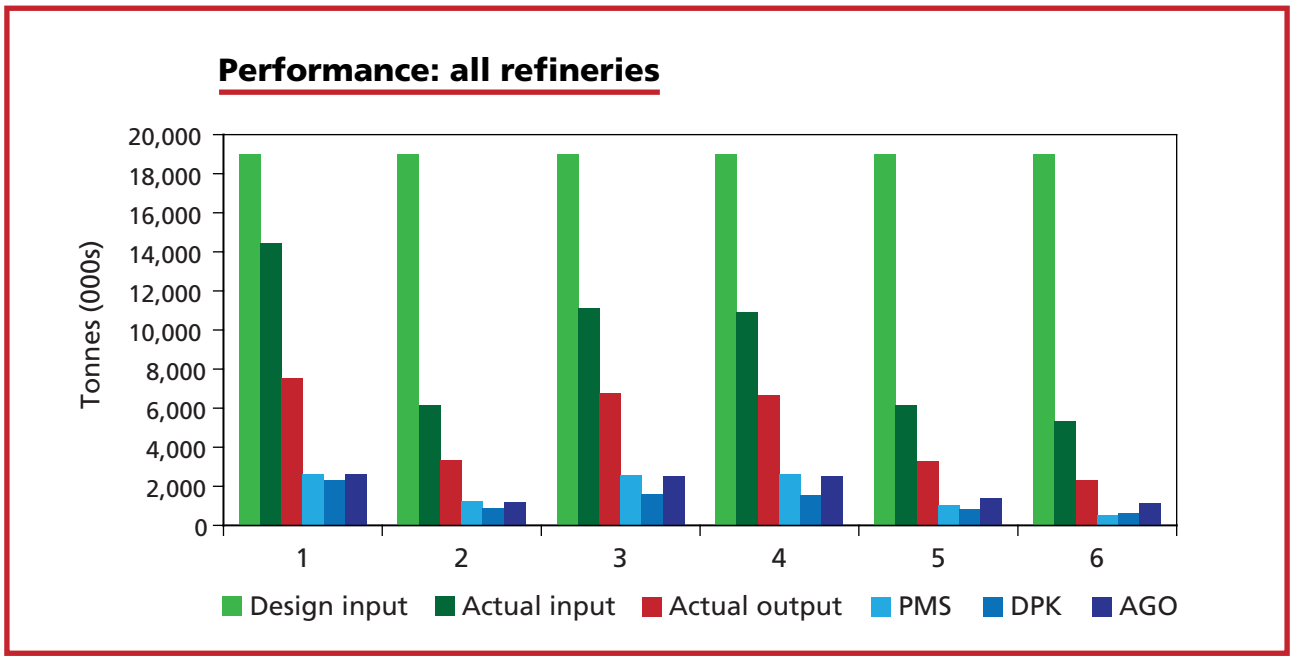
A tender committee is then chosen from all segments of NNPC, which include PPMC, the group managing director's office, and the legal, administration and accounts departments, in a bid to establish transparency in the tender analysis. Sealed tenders from different companies for term contracts to supply product are analyzed for bid price, freight costs, status of the company, price and payment terms.

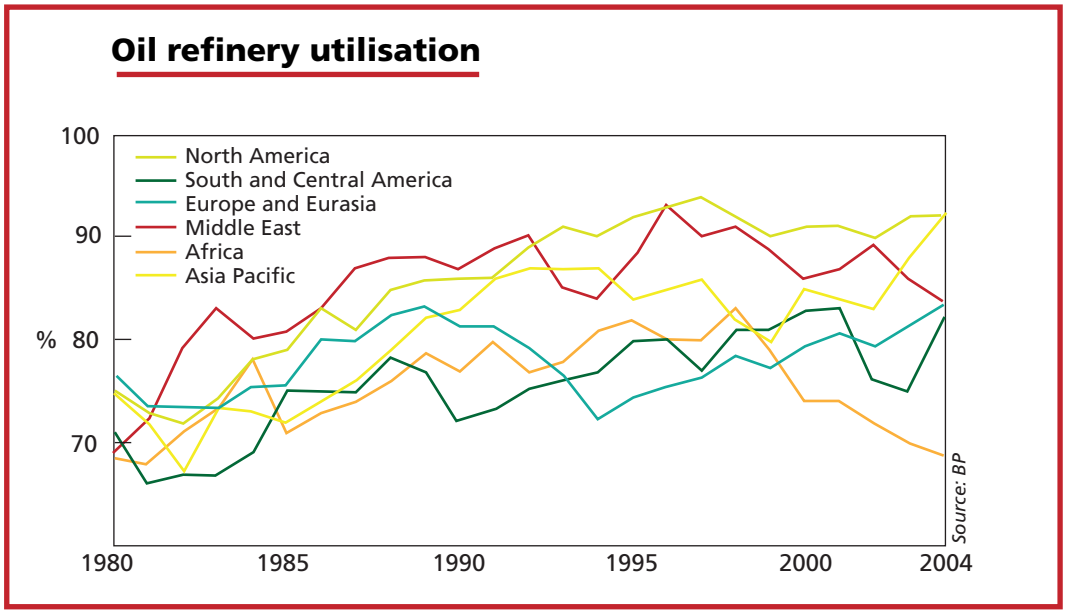
To be licensed with the DPR to import products into Nigeria, a company has to meet several requirements, including having a good credit rating. After 2004, the requirements became much more stringent. Prequalification requirements were strengthened to include: turnover of at least $5 billion a year or a minimum credit rating of BBB by Standard & Poor's; a relationship with a refinery; a global presence, and at least four years' trading experience with Nigeria. This tougher criteria narrowed the list of prequalifiers to global oil giants Total, BP, Shell and Chevron, European traders Glencore, Addax, Trafigura, Arcadia and Vitol, and Nigerian companies Calson/Hyson and Napoil. However, the requirements were later relaxed.

DPR is the regulator of refined product imports, issuing licences for storage and reception facilities, granting permits to importers, and setting standards that imported products must meet.

Findings

Refinery utilisation was extremely poor (see chart below to gauge global capacity utilisation rates). Port Harcourt never worked at more 67% of its design capacity over the audit period. Warri never performed better than 65% at peak, while Kaduna





peaked briefly at 59% in 2000. The average for the refineries was a 42.7% utilisation rate – meaning more than half their nominal capacity was unused – less than half the global average of 85% over the period. The poor performance was due mainly to management failure to allocate enough resources to repairs and maintenance, although pipeline sabotage contributed, as this cut off crude supplies to the refineries.

The import process, including tendering, contracting and procurement practices, falls short of good practice standards, and puts government interests at risk. Procedures and approvals processes are not clear; where they do exist they are inadequate.

The current written procedures have not been approved by NNPC's board. Since they set authority levels for PPMC directors, it is essential they are approved by NNPC. These procedures grant what seems unnecessarily broad scope for discretionary management decision-making on the pricing of import contracts.

The audit compared the actual volumes PPMC imported between August and December 2004 and the amount that had been approved for import. Actual volumes exceeded the amount approved by more than 700,000 tons. PPMC says this was because the refineries fell short of their contribution to the forecast supply/demand balance. Auditors were told that the excess had been approved, although no evidence was provided.

Savings on PMS imports in 2004 could have amounted to at least $120 million had the refineries worked more efficiently. Refinery utilisation, or crude throughputs, averaged 41% of capacity that year, less than half the world average of 85%. This was primarily due to poor management processes at the refineries, although pipeline vandalism and equipment failures in moving the crude also affected supplies. The poor performance meant Nigeria also had to import kerosene and diesel. With better performance, the refineries could have exported both kerosene and diesel.

It is clear that Nigeria will have to import a significant portion of its PMS product needs in the foreseeable future.

PPMC completed templates for imports, exports and movement of refined products in three separate exercises undertaken in December 2005, June 2006 and December 2006.

There were significant differences between the volumes of crude NNPC reported it sent to the refineries and the amounts the refineries said they had received. There is no evidence of a regular process of reconciliation. For the six years from 1999 to 2004, PPMC refinery records indicate their receipts of crude were 21.6 million barrels higher than COMD recorded as supplied, or 5.63% of the total.

Recommendations

- Measures for improving refinery utilisation should be examined to maximise the economic benefits for Nigeria. Money should be spent on efficiently managed maintenance projects and back-up systems to improve performance. The refineries should also be credited with the value of the products they produce at the average price that PPMC pays for importing products. This would indicate the refineries' contribution to reducing the cost of imports.

- An operational review of the receiving facilities should be carried out to determine whether their capacity is being used as well as possible, and whether their state of repair and maintenance is adequate.

- Written procedures should be developed covering all aspects of the tendering and import process. This should include the setting of prices for imported products, as well as the selection process for suitable companies. Levels of authority should also be formalised for prequalifying importers and determining prices to be paid for imported products.

- The process for importing refined products should be reviewed, since discretionary powers are unnecessarily wide. Internal auditors should review the way procedures operate.

Alternative models of price setting for imported products should be considered. These include inviting bids for specific products, at specific prices, and building up supplies by taking the cheapest first, which can be effective provided that the pool of suppliers is large enough.

There should be a formal process – including the introduction of reports – to monitor volumes of PMS imports against amounts approved by the government.

Systems for measuring, recording and controlling the movement of refined products and crude feedstock for the refineries require improvement. All areas should be examined, including: imports; crude oil volumes sent from terminals to refineries; volumes received by refineries; product sent from jetties to depots and between depots; and reconciliation of the volumes of crude oil sent to refineries with output of finished product.

The large increase in product imports has overwhelmed jetties that were not designed to support such volumes, causing shipping delays and demurrage charges – the money ship charterers have to pay ship-owners for extra use of a vessel. NNPC needs to increase capacity at jetties and depots to handle more imports efficiently.

Section 4: Budget and Management

Capital and Operating Expenditure

This audit investigated how companies decide on big one-off capital investments, and how they plan and control day to day operating costs in the joint ventures with NNPC that they operate. It also looked at how budgets are approved and monitored, and systems and procedures for contract awards and procurement.

The audit looked at the processes leading to the so-called Final Investment Decision (FID) – the green light to move ahead with a project. It explores how companies evolve and plan, what criteria they used to judge one scheme versus another, and how they assessed the risks.

Particular attention was paid to NNPC's role and its access – or lack thereof – to computer modelling facilities when shaping investment decisions. The key questions included whether the joint ventures' decisions are consistent with national aspirations, whether the industry is following best practices, and whether NNPC is delivering value for money.

Methodology

A pilot review was undertaken of decision-making at two operators, and questionnaires were sent out to 14 companies and two government entities (*see Process Audit, appendix L*).These were followed up with interviews.

Joint venture operators complain that for all the importance of the capital investment process, execution is often delayed and frustrated by difficulties linked to the government's annual budgets, which approve funds for NNPC's share of joint venture investments. Government approval is invariably late, funding is intermittent, contracts get delayed, and costs tend to rise.

Findings

The audit found that companies' objectives are generally aligned with national aspirations, which include boosting production capacity to 4 million b/d by 2010, increasing reserves to 40 billion barrels, and diversifying from oil towards an integrated oil and gas industry.

The bigger companies assess proposed projects in light of their international asset portfolios and measure their potential returns against those of other schemes. Big capital investment decisions tend to follow a "five stage gated" process (see *Process Audit: Processes for capital and operating expenditure p14*). This involves rigorous road testing and risk analysis throughout. Significant investment in analysis and personnel is made during the first three stages, up to FID, which can be some 10–20% of total project engineering expenditure.

NNPC is a joint venture partner and its National Petroleum Investment Management Services (NAPIMS) department acts as portfolio manager in the joint ventures. **However, it is not clear whether NNPC/NAPIMS undertakes any real independent technical and economic evaluations of potential projects, or whether it relies on the operators, its joint venture partners, to provide the information it reviews. It lacks a portfolio management system, and there appears to be a potential conflict between its role as joint venture partner on the one hand, and contract manager supervisor on the other.**

Recommendations

- All companies, big and small, should adopt well-documented staged processes to take project opportunities from inception to execution and production to improve scheduling and budget control.

- NAPIMS should have its own processes for assessing technical proposals, capital costs and expenditures within NNPC, including its own project ranking and performance benchmarking systems to rank projects according to national goals.

The Budget Approval Process

Budget approvals for the joint ventures' expenditures invariably run late: during this audit the overall budget for 2006 was still awaiting a green light three months into the budget year. Such delays cause work slowdowns, delay contract signings, and often incur extra costs.

The budget approval process is governed by procedures laid out in the Joint Operating Agreement (JOA) – a standard agreement that governs the relationship between the operator and investors.

The companies develop business plans in line with government objectives and NNPC guidelines. They submit the plans to NNPC/NAPIMS, where they are scrutinised and reviewed with the companies by specialist subcommittees, who compile reports.

A jointly agreed programme is then developed by the all-important technical committee, and submitted to the operating committee for consideration and approval. The operating committees are headed by operations managers and representatives of NNPC and NAPIMS in their capacity as investor and portfolio manager respectively.

The budget then proceeds to NNPC's top management, the Finance Ministry, the cabinet and the National Assembly, which then often cuts the budget. The cuts force the companies back to the drawing board to realign programmes to fit the amounts approved. Alternative funding arrangements are sometimes set up to cover shortfalls on projects deemed essential by the cabinet and companies.

Findings and recommendations

The audit found the processes bureaucratic, prone to micromanagement at high level, and risky for big projects, the funding for which has to be approved every year.

- The audit suggests that the budget be approved in principle at the operating committee stage – which would require more delegation to NAPIMS representatives on the committee. This would enable the joint ventures to line up alternative funding, such as project finance, earlier in the event that politicians slash the budget.

- The other alternative would involve a top down process, in which the National Assembly and the Presidency allocated NNPC/NAPIMS a set budget in advance, along with set targets and goals for which they would be held accountable every year. They would be wholly responsible and accountable for allocating the funds to each of the joint ventures.

The contract award process

Turning to contract awards, the audit paints a very mixed picture. In theory, the processes appear open and inclusive, and conducive to good practice. They include prequalification, technical qualification and evaluation of commercial proposals, with the award going to the lowest bidder. Invitations to prequalify and tender are advertised, and tenders are opened in the presence of representatives from all parties.

However, in practice this involves 31 steps. The process, which can take 18–24 months, undermines the annual budget cycle. It is also subject to interference by outside parties at various stages, and frequently results in awards to financially weak or poorly qualified companies, one firm told the auditor. NAPIMS' approval is required at almost every step.

The audit recommends that the process should be accelerated, and that NAPIMS' role could be rationalised, confining it to more strategic points in the process, where representatives are empowered with delegated authority. It also stressed that awards should go to contractors offering "best value", rather than those submitting the lowest prices. This could require more scrutiny at prequalification and technical levels, to eliminate likely non-performers.

Chapter 5

Remediation Efforts

The Federal Executive Council asked NEITI to devise a strategy to address the lapses identified in the audit. An inter-ministerial task team (IMTT), grouping government petroleum and finance department heads, was set up to discuss how to implement the audit's recommendations.

The IMTT has outlined a five-track approach dealing thematically with the issues:

- Revenue flow interface between government agencies;
- Improvement of Nigeria's oil and gas metering infrastructure;
- Cost determination and related issues;
- Infrastructure and human capacity building; and
- Improvement of petroleum sector governance.

The revenue flow interface project:

This aims to tackle shortfalls in financial reporting and management. The audit recommends that financial information should be improved, shared and updated through new technology and regular reconciliations, and that the Accountant General of the Federation (AGF) should exercise greater management and control. This could be achieved through the introduction of modern financial management systems and techniques, including predictive modelling to enable the AGF to manage financial flows from the sector.

Progress The IMTT has agreed that each agency and government department should draw up standard procedural instructions on its systems and forward them to the Hart Group to make a flow chart. This would identify gaps and eliminate overlaps in functions, and promote the sharing of data and information in real time – as transactions occur and prices change.

Communications have improved, with key petroleum agencies meeting regularly to share information and reconcile data. The AGF and Federal Inland Revenue Service (FIRS) hold monthly meetings with Nigerian National Petroleum Corporation (NNPC), the Central Bank of Nigeria (CBN) and the Revenue Mobilisation Allocation and Fiscal Commission (RMAC), to reconcile figures in preparation for meetings with the Federal Account Allocation Committee (FAAC).

In the future, NEITI will explore ways to connect agencies on a virtual on-line real time platform. NNPC and CBN have deployed new IT applications, which have enhanced their operational efficiencies. A SAP software package will be developed to improve the revenue flow interface.

The CBN now generates credit advices automatically every day, which are delivered to relevant agencies. The DPR has instructed all oil and gas operators to pay the CBN and copy all other relevant government agencies. NNPC now provides advance information to relevant agencies before FAAC meetings. Its Crude Oil Marketing Department (COMD) holds monthly reconciliation meetings with NNPC's Group Treasury to resolve any differences in sales and cash collection reports.

Metering

The audit called for companies to provide a hydrocarbon mass balance on a routine basis, to confirm the crude oil volumes on which royalty and PPT are based. It recommends that arrangements for monitoring gas and liquids, from well-head to

terminal, should be reinforced. Also, the DPR should work together with operators to develop reporting guidelines and standards.

Progress The IMTT's Measurement Working Group is gearing up for a comprehensive study on metering and measurements in Nigeria's oil and gas facilities, for which the UK's Department for International Development has committed funds. NEITI has already consulted metering experts on best practices around the world, and has sought technical support from the Norwegian government.

NNPC has conducted a report on the products pipeline network, and developed a plan for repairs. Its $15 million plan includes replacing 33 sections of pipeline between Atlas Cove and Mosimi, and other sections between Port Harcourt and Abia.

Cost determination and other related issues

The auditor called on FIRS to improve its record keeping, and to set up a reliable system to ensure that companies are properly assessed and pay their taxes on time.

Progress The IMTT convened a stakeholders' meeting with oil companies' representatives to agree a uniform approach towards assessing costs and to discuss the variations. However, more work needs to be done, and FIRS has yet to produce a tax manual.

FIRS has met with oil companies to resolve the outstanding differences over operating costs, intangible and drilling costs and determination of fixed assets identified by the audit. Some contentious issues are still under scrutiny.

NNPC hope to agree uniform approaches to cost determination with the international oil companies operating its joint ventures. National Petroleum Investment Management Services (NAPIMS) is studying uniform accounting procedures for the industry.

Infrastructure and human capacity building

The audit called for comprehensive training to address significant skills gaps in most government agencies, where many officials are insufficiently trained and equipped.

Progress The NEITI secretariat has piloted a training course in petroleum revenue management for senior government officials of all agencies involved in the remediation effort.

The CBN is working on a plan that will outline its training needs. The DPR has yet to produce a plan. The FIRS has submitted a plan outlining training requirements, and is now looking for finance. NNPC is the subject of government's broader reform programme to restructure the company.

The Office of the AGF has identified poor computer literacy as an issue. It will organise in-house training in information technology, and is working on a plan to upgrade skills across the board.

Governance

The audit recommended a thorough review of the institutional arrangements and relationships between government agencies and departments. Information sharing between all sector participants – private and public – is essential, while government regulators and the industry need to take a holistic view. The government cannot correlate the financial flows with physical flows, and its lines of responsibility are not clear. The financial data's validity depends on the technical data, but no one has responsibility for overseeing linkage between the engineering and physical transactions on the one hand and the financial transactions on the other.

Progress The NEITI/IMTT aims to draft a roadmap for oil sector governance and policy reform to redirect oil sector policy responsibility and accountability to the government

and away from NNPC. This will focus on improvement of DPR's regulatory capacity, elimination of NNPC's opaqueness, and providing a work plan to feed into planned restructuring of NNPC, the DPR and NAPIMS. It will also call for development of a best practice template to ensure transparency in the sale of government equity crude and licensing of oil blocks.

NEITI
Nigeria Extractive Industries Transparency Initiative

www.neiti.org.ng