



FINAL DRAFT

in association with



CMA Ltd



SS Afemikhe Consulting Ltd

Nigeria Extractive Industries Transparency Initiative (NEITI)

PHYSICAL AUDIT 2005

FINAL DRAFT REPORT

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Presented to the National Stakeholder Working Group

by
Hart Resources Ltd
In association with
SS Afemikhe Consulting Ltd
CMA Ltd

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

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Part 1: Summary of the Physical Audit 2005

1 Introduction

The scope of the Physical audit encompasses the mapping of hydrocarbon flows, the assessment of the quality of procedural systems, the technical assessment of measuring hydrocarbon streams, the volumetric analysis and reconciliation of data, recommendations for improvements and reporting templates, and the aggregate reporting of hydrocarbons produced and fiscalised in the audit period 2005.

This summary presents an overview of the data collected from companies (field operators, terminal operators, lifters), NNPC and the Department of Petroleum Resources and reconciled by the auditors.

The summary also presents a synthesis of the findings of the reviews of certain key processes affecting the management of the sector.

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The status of this report is "final draft". Some sections of the report are being reviewed by relevant entities and are therefore subject to factual correction.

2 Summary statistics for 2005

2.1 Production, allocation and lifting

Nigeria's oil and gas production activity during 2005 comprised twenty separate operations. The production by each operator was the following:

Operator	Bbl millions
SPDC JV	337.6
MPNU JV	213.9
CNL JV	133.1
EPNL JV	75.7
NAOC JV	61.8
AENR	24.2
Addax	23.8
Continental	13.2
NAE	11.3
PanOcean JV	8.6
MoniPulo	5.8
NPDC	2.1
Express	1.6
SNEPCO	1.5
Cavendish	1.4
Amni	0.8
Conoil	0.7
Atlas	0.2
Dubri	0.2
NDPR	0.1
Total	917.7

Note: Addax, NAE and SNEPCO operate PSCs on behalf of NNPC. AENR operates service contracts for both NNPC and NPDC. Unless identified as JV, all other operations are on a Sole Risk basis.

The entitlement of each company to the produced crude was the following:

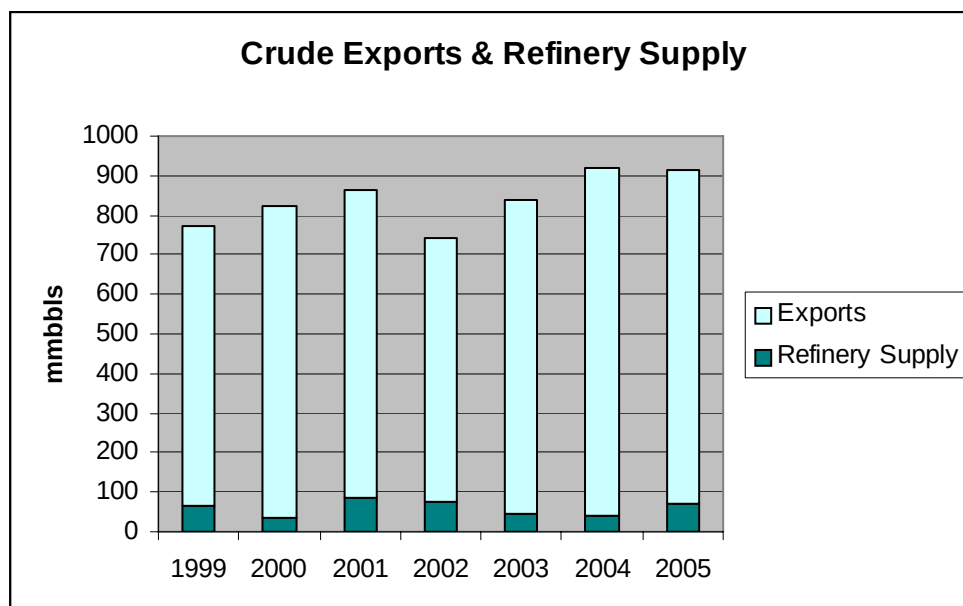
Company	Bbl millions
ADDAX	14.6
AENR	8.5
Amni International	0.8
ATLAS	0.2
CAMAC	0.0
Cavendish	1.4
CNL	54.3
CONOIL	0.7
Continental	13.2
DUBRI	0.2
EPNL	73.8
EXPRESS	0.9
Moni Pulo	5.8
MPNU	106.4
NAE	4.3
NAOC	30.6
NDPR	0.1
NNPC	454.0
NPDC	15.1
PanOcean	3.5
PHILLIPS	12.4
SEPCOL	0.7
SNEPCO	5.8
SPDC	109.6
Total	916.9

Nigeria has five onshore terminals and during 2005 twelve offshore floating production / storage terminals. The 2005 activity at terminals may be summarised as follows:

Operator	Terminal	Crude Production	Crude Liftings	Stock change
		bbl millions	bbl millions	bbl millions
ADDAX	ANTAN_KnockTaggart	23.0	23.3	0.3
ADDAX	OKWORI_Sendje	5.3	4.5	-0.8
Amni International	IMA_Ailsa Craig	0.8	0.8	-0.1
Cavendish	OBE_Crystal Sea	1.4	1.5	0.1
CNL	Escravos	111.8	111.4	-0.4
CNL	OLOIBIRI_Penn	18.7	19.0	0.3
EPNL	ODUDU_Unity	69.1	69.4	0.3
MPNU	QIT	137.8	138.0	0.2
MPNU	QIT (Cond)	23.1	23.0	0.0
MPNU	YOHO_Falcon	49.1	48.7	-0.4
NAE	ABO_Gray Warrior	11.3	11.8	0.5
NAOC	Brass	71.9	72.4	0.6
NPDC/AENR	OKONO_Mystras	19.9	19.9	0.0
Shebah (SEPCOL)	UKPOKITI_TrinitySpirit	1.8	1.9	0.1
SNEPCO	BONGA	1.5	0.2	-1.3
SPDC	Bonny	180.7	179.7	-1.0
SPDC	EA_Sea Eagle	42.4	42.7	0.3
SPDC	Forcados	148.1	147.8	-0.4
TOTAL		917.7	916.1	-1.7

2.2 Exports and refinery supply

During 2005, some 916 million barrels of crude oil were lifted from Nigerian Terminals - almost exactly the same quantity as in 2004. However, the amount used for local refining almost doubled from 38.8 million to 72.1 million barrels.



Liftings Summary

	1999	2000	2001	2002	2003	2004	2005
Refinery Supply	66.0	36.2	84.1	77.8	43.2	38.8	72.1
Exports	707.2	789.5	780.3	663.1	796.6	878.1	843.9
Total	773.2	825.7	864.4	740.9	839.8	916.9	916.0

The quantities delivered to NNPC refineries and the main outputs of those refineries were as follows¹

Summary of Refinery Supply and Production

	Oil	Products Production		
	Crude Supply (bbls)	PMS (tonnes)	DPK tonnes)	AGO (tonnes)
KRPC	520,742	388,173	228,082	418,837
WRPC	31,537,386	674,315	456,840	732,312
PHRC	40,128,252	675,602	613,468	971,437
total	72,186,380	1,738,090	1,298,390	2,122,586

¹ note that refineries require other inputs than the local crude supply and produced more products than those shown; a direct comparison of these inputs and outputs would be misleading.

2.3 Refined products

Our best estimate from the data provided by PPMC gives the following position for the three products under consideration, on the assumption that the stock positions are correct:

tonnes	PMS	DPK	AGO
Opening Stock	712,120	370,330	265,005
Product Imports	5,384,587	517,292	-
Refinery Production	1,738,090	1,298,390	2,122,586
Product Sales	-7,010,563	-1,803,175	-2,179,728
(Losses)/Gains	-287,297	-150,610	13,818
Closing Stock	536,937	232,228	221,681

The estimated value of product losses during 2005 is US\$ 239 million. The cause of the losses has not been identified. It could include pipeline vandalism, leaks, measurement error, analysis error or theft but PPMC has not provided analysis of incidents.

An in-depth review of depot measurement and metering practices was undertaken. This concluded that the quality of data available on product movement is insufficient to validate the reconciliation of product flows. This is due to the widely varying measurement practices in place at downstream depots.

The audit process built on the discussions held with PPMC during the 1999-2004 exercise and sought to model the product flows from balances across the individual depots. We previously recommended steps that PPMC should take to improve their capacity to report to NEITI and also for management purposes. It should be noted that our recommendations were made at the conclusion of the NEITI 1999-2004 audit, at which time it would have been too late for PPMC to take any action that would improve the 2005 situation; accordingly, the recurrence of these findings and recommendations is not surprising.

Considerable work is required to improve the quality of the underlying data. This should focus on:

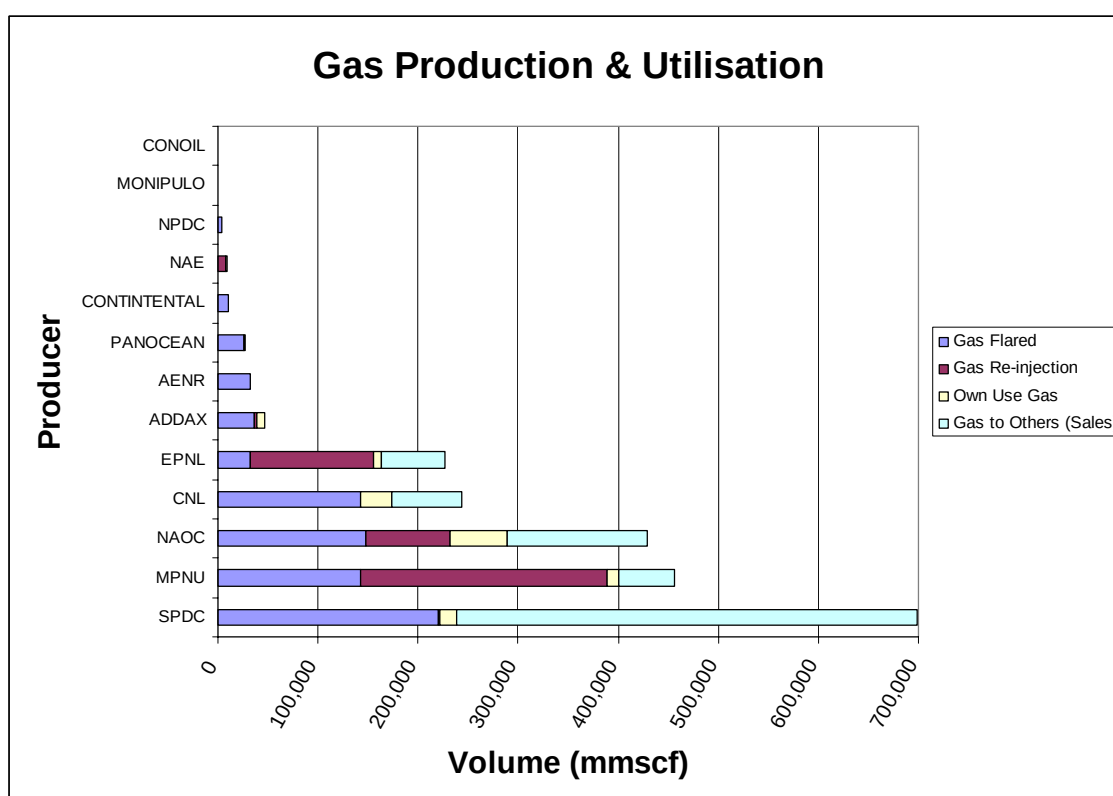
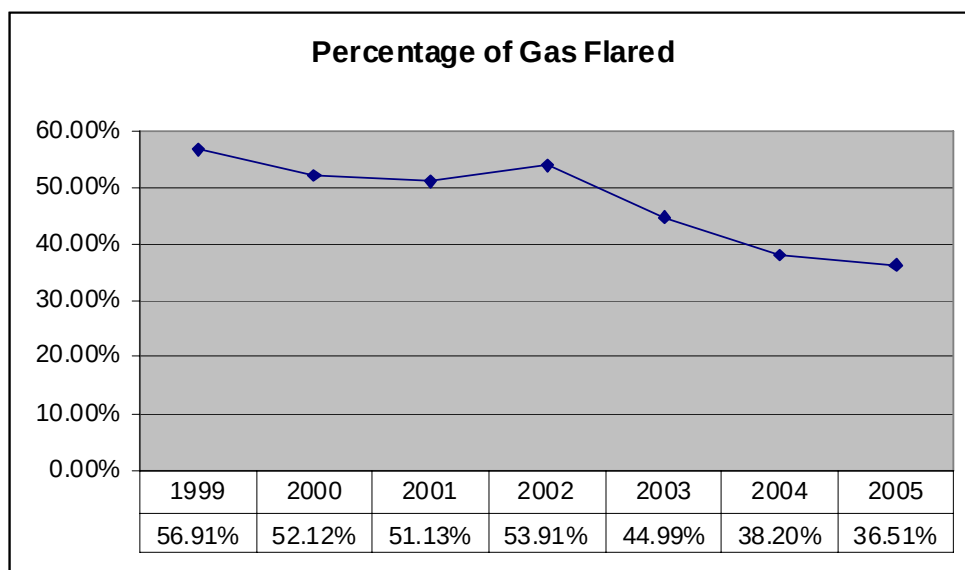
- Standardised/monitored measurement procedures at depots
- Capacity building of depot staff to provide reliable, repeatable measurement data
- Review of depot reporting procedures, and more frequent reconciliations, to minimise errors and provide timely indication of problems
- Review of pipeline monitoring practices
- Review of storage volumes and remediation to minimise unnecessary product transfers and demurrage costs.

2.4 Gas

Gas production and utilisation data for 2005 is summarised in the following graphics.

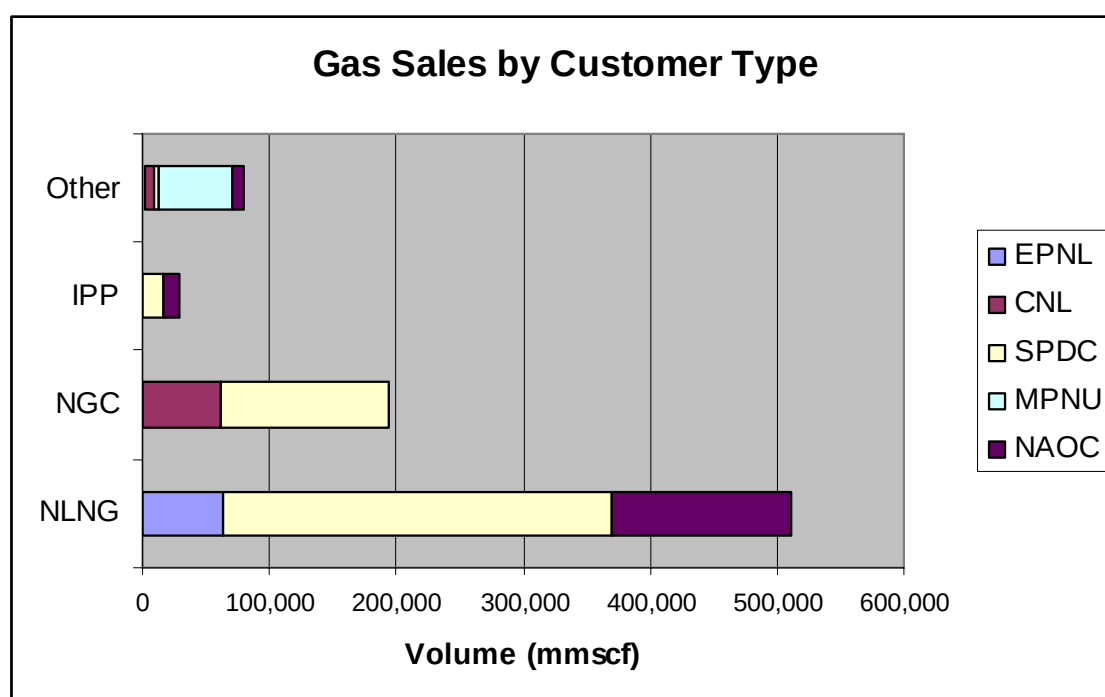
Nationally, the quantity of gas flared is approximately equal to the amount commercially sold. The proportion of total gas flared has continued to decline, though at a slower rate than in the previous three years.

It should be noted that the available data on gas volumes is not independently corroborated, as producers and customers share the same meter readings. Further, gas flaring statistics are as reported by companies: a standardised methodology for determining quantities of gas flared has not been established and regulation of gas generally requires strengthening.



Producer	Gas Flared	Gas Re-injection	Own Use Gas	Gas to Others (Sales)	Total Gas Produced
SPDC	220,838.991	770.104	17,311.859	459,354.933	698,275.886
MPNU	142,632.494	246,061.591	11,239.448	57,006.452	456,157.219
NAOC	148,222.453	83,719.009	57,085.403	139,976.824	429,003.689
CNL	142,331.137		30,830.549	71,118.655	244,280.341
EPNL	32,201.542	123,557.562	7,099.760	63,681.022	226,539.886
ADDAX	35,946.000	3,038.000	7,492.000		46,480.000
AENR	32,035.777		686.969		32,722.746
PANOCEAN	25,868.237		1,299.262		27,167.499
CONTINENTAL	9,981.486		103.546		10,085.032
NAE	151.960	8,242.520	1,300.710		9,695.190
NPDC	3,795.623		199.770		3,995.393
MONIPULO	1,584.266		273.176		1,857.442
CONOIL	391.800		16.360		408.200
Total	795,981.765	465,388.785	134,938.811	791,137.886	2,186,668.523

Most gas is sold to NLNG for liquefaction:



As more IPP (Independent Power Projects) schemes come on stream and as companies seek to utilise more gas to comply with the FGN zero flare target, it becomes ever more urgent to place these gas developments on a solid regulatory and operational footing. For example, it is not transparent how operations transfer gas between them for operational purposes and whether or not such transfers should constitute a "gas sale" and incur a CITA liability.

3 Methodological approach to data collection and reconciliation

The approach to the 2005 Physical Audit was an incremental improvement on the 1999-2004 audit. The previous audit was the first time this exercise had been attempted and a number of improvements were implemented for 2005:

- Clear distinction between the operating entities (Joint Ventures, PSC operators etc) and Lifting companies.
- Need to reconcile data from at least two different points. The intention was to compare field measurements from operators to terminal operator data and then to lifter data.
- Need to acquire cargo-by-cargo data from all parties to facilitate reconciliation
- Pragmatic recognition that the first point at which sensible measurement data might be available is at the flow station – not the wellhead.

Difficulties encountered and recommendations:

Slow return of data from a number of companies. In order to finalise a balance at a particular terminal data is required from all companies using that terminal, either as operators feeding crude in, or lifters as well as the terminal operator. The audit could only progress when the data was returned from the slowest provider.

Companies generally conformed, but often misinterpreted the data requested (or made assumptions about what was needed). Some NNPC and FGN entities chose to ignore some templates altogether and provide data that approximated to what was required in their own format. DPR refused to provide physical data on the new templates.

Companies continue to provide net-back data rather than field source data. This issue will continue until field metering guidelines are agreed and implemented. Consequently, even though the framework now exists to produce a gross physical balance the outcome will remain a net balance.

Agreement needs to be reached with terminal operators regarding how 3rd party crude is reported, particularly with regard to stock levels, terminal adjustments and the point in the process at which stock can be accurately attributed to beneficial owners.

We recommend that process of reporting on the mass balance be embedded, so companies and government entities become familiar with the routine. More attention is needed to the accurate completion of templates.

There is a need to pursue the question of the rules surrounding royalty payments and the point at which liability for payment arises (if payment on Production is an important principle to retain/reinforce, a simple option would be to make the Operator liable for Royalty payments following agreement with DPR on the production from each field). If the current position is retained, DPR needs to make careful distinction between the legal entities that are allocated product and entitled to lift and the operating ventures that produce it.

It is important to continue to work on metering and measurement guidelines. It is perhaps worth considering fast-tracking specific guidelines for offshore, which is generally simpler and more controllable than onshore.

It is also important to continue to refine the templates. The stage has almost been reached where production templates can be created specific to each operation, rather than force-fitting each into a standard. This should simplify the data collection process.

4 Review of measurement processes

4.1 Upstream metering

The purpose of the audit was to review sector progress in designing and implementing enhanced measurement arrangements for upstream hydrocarbon flows.

The main issue raised under the 1999-2004 audit was the apparent lack of in-field measurement as a basis for determining wellhead production. No changes have been implemented. The 1999-2004 audit took place in 2005 and 2006, so the timing of the recommendations did not allow for any changes to be made during 2005. Nevertheless, this issue has begun to be addressed by an Inter-Ministerial Task Team.

Meetings were held with DPR, ExxonMobil and TotalFinaElf (as representative of upstream operations) to obtain an overview of progress made to implement the recommendations of the 1999-2004 audit. Templates were issued to upstream companies requesting details of changes to metering equipment and processes. Returns from companies indicate that the system and procedures in place for measurement have not changed materially since the previous audit. A small number of companies have however implemented improvements in line with the recommendations.

Further, one upstream company has made proposals to DPR for changes to the metering guidelines in the light of changes in international best practice.

Whilst some discussions are underway and technical advice has been sought by DPR from the Norwegian Government, progress remains slow.

As companies install new, and upgrade old, equipment they would like to take advantage of the recent technological advances – currently this is not possible since DPR will not accept their use of (for example) digital thermometers and data from flow computers.

Even if a consensus cannot be reached on a common approach to field metering, it would be prudent for DPR to issue updated guidelines on some aspects of measurement (albeit interim) guidance to permit companies to make use of internationally accepted measuring devices.

4.2 Measurement of Products

A number of important issues arose during the course of the audit at locations operated by NNPC PPMC, relating to the measurement of petroleum products (Petroleum Motor Spirit, Automotive Gas Oil and Kerosene).

- ❑ Lack of adequate operating and maintenance procedures
- ❑ Lack of fit for purpose measurement points at import to / export from an installation.
- ❑ Lack of knowledge of regulatory guidelines over a variety of activities relating to assessment and reporting of quantities of petroleum products
- ❑ Inconsistent approach between locations operated by PPMC for the measurement of density and temperature of products in the storage tanks.
- ❑ No culture of striving to follow international best practices
- ❑ Lack of training

The consequence of these weaknesses can be seen in a number of areas, some of which are crucial to protecting the government's legitimate commercial position in the import and sales of petroleum products.

5 The Process of Marketing Federation Equity Crude

The main findings of the work are that, for the year 2005:

1. Final decisions about setting NNPC's Official Selling Price were taken at a very high level within NNPC, and the Ministry of Energy. This process takes much time before the approved OSP price can be communicated to the off takers, leading to unnecessary uncertainties with existing and new off takers, at an implied cost to the Federation.
2. The COMD off-taker list is not well balanced. COMD should consider increasing the off taker list with final end user buyers/major oil companies at the expense of current large contract allocation to traders.
3. The OSP methodology is sound and well conducted. However it seems somewhat conservative and without any NNPC COMD participation as a spot crude oil trader in the oil markets one can ask if the 2005 (whole year) average difference of 0.25-0.30 \$/barrel between OSP and the average Platts during the month prior to OSP applicable month should be reviewed by NNPC and be brought more in line with observed period Platts averages (for illustration, a difference of US\$ 0.10 / bbl amounts to about US\$ 87 million over a year).
4. NNPC should review whether to use other crude oil benchmarks besides Brent. Given the preponderance of sales into the US refining areas the US crude oil benchmark West Texas Intermediate (WTI) may give a better value basis than European market benchmark Brent.
5. NNPC charges only 0.03 \$/bbl (average for 2005) for the pricing option. This looks rather cheap compared with the benefits for the off taker certainly with the till very late allowed declaration moment for the option (5 working days before the loading takes place). NNPC should consider increasing the price for the option, more in line with the CFD derivatives market.
6. NNPC should review the use of Calson (Bermuda), its joint marketing company with Vitol. This marketing arrangement may present a conflict of interest between the Vitol and NNPC (on behalf of the Federation).
7. Guidelines for off taker selection should not include a requirement from the off taker to invest in Nigerian projects. Where the guideline is applied, the sale contract should include appropriate clauses dealing with the project. Such a requirement will theoretically lead in the longer term to the Federation securing a lower price for its crude. Further, COMD has no means of checking whether the required performance has indeed taken place, nor any defined procedure for the eventuality that it appears it has not.
8. The execution of contracts with Bilateral parties should be a NNPC final responsibility.
9. Volumetric measurements of gross and net loaded barrels should be reviewed in the light of observed round figures for Bills of Lading volumes. Out of the sample of 63 contract sales we reviewed, at least four were subject to uncertainty as to how the invoiced volume had been determined.
10. The payment security for all sales contract is well organised and considered in principle to be a well designed instrument to guarantee all revenues into the respective bank accounts.

6 The activity of the NNPC offshore marketing companies

We await data from NNPC regarding the transactions of offshore marketing companies to enable this work to commence.

7 The process of licensing in the Joint Development Zone

7.1 Scope and execution of work

The consultants were required for the purpose of the present audit to obtain data from the Ministry of Petroleum and the Joint Development Authority concerning various aspects of the procedures for allocation of licenses in the Joint Development Zone during 2005 (the second licensing round). The Terms of Reference for this work are set out in Appendix 5.

The JDA refused to meet the consultants. The consultants were not able, nor were the NEITI secretariat able, to facilitate the provision of any relevant information. This is somewhat surprising because both governments² had agreed (see Appendix 4), in the course of the EITI conference in Oslo (October 2006) that EITI should be the vehicle for transparency in the JDZ.

Nevertheless, the consultants were able to obtain some information from other sources, principally published information. This has enabled the consultants to present, for the information of the National Stakeholder Working Group, an overview of the licensing round and a large amount of the information specified by the Terms of Reference. It should be emphasised however that this information is unverified. In particular, the consultants strongly preferred to check the information and interpretations with the JDA directly rather than rely on other sources but the JDA informed the NEITI secretariat that they were unwilling. Should the JDA change its approach, there is a programme of work that the consultants would wish to carry out (Appendix 6).

7.2 The interests of Nigeria

The Joint Development Zone is covered by an international treaty that gives Nigeria a 60% stake in the Zone. Nigeria's principal interest appears to be to maximise revenues from the development of oil and gas resources in the Zone. It should be noted however that the JDA is concerned not only with hydrocarbons but with all aspects of development of the zone, notably fisheries and environmental protection.

Although the verification of remittances from the JDZ is outside the scope of this work, the consultants were not able to obtain any clear understanding of the policies and procedures in place for remitting Nigeria's share to the Federation. Nigeria was ostensibly entitled to US\$ 170 million from the signature bonuses from the 2nd licensing round.

All blocks are under exploration at present. It will be necessary in future to develop a mechanism for dealing with production that is shared to the JDA.

7.3 The Licensing Process

Adequacy of the tender process

The Government of Sao Tome & Principe has publicly acknowledged that the tender process had not been transparent and contained technical flaws. The existence of irregularities has been acknowledged. The Deputy Director (Monitoring and Inspection) of the JDA stated publicly additional criteria, inconsistent with the published Guidelines, had been applied in the second bid round. Additionally, there has been external criticism of the round.

The JDA declared that it would undertake a post-mortem of 2nd bid round: in the absence of any information, it is not known whether this has been done, or what results emerged from it.

² It is understood that the JDZ exists as a separate entity under international law, which is said to preclude Nigeria unilaterally deciding to undertake EITI work in relation to the JDZ.

Competitive tendering

The possibility exists that blocks may be awarded on a discretionary basis. This can occur if the Joint Ministerial Council so decides, although the preconditions (if any) and framework for the exercise of this discretion have also not been given. In every other case there should be a competitive tender. In the interests of economics, the optimum outcome is usually attained through a competition. It is unclear why this exceptional discretion remains.

The position of ERHC

There has been considerable press comment on the fact that ERHC which is under investigation for possible breaches of US Federal Securities laws obtained positions in several blocks. ERHC was taken over by Chrome, a company said to be in Nigerian ownership. The company had a pre-existing agreement with the government of Sao Tome but otherwise had no activities. The consultants are not in a position to comment on this situation, due to lack of access to any primary documentation.

Length of the tender procedure

The timescale (duration) of tender processes is too protracted. The tender was opened on 15 November 2004 and closed on 15 December 2004. The award was not made until 24 May 2005.

7.4 Signature bonuses

On 3 May, 2006 the JDA announced that it had in respect of signature bonuses for Blocks 2, 3 and 4 received a total of \$145 million. The total, based on the declared offers for each block, should have been \$201 million, all of which was payable (according to published rules) within 30 days of award. The difference should be explained.

As noted, the operation of the procedure for remitting signature bonuses to Nigeria is unclear.

7.5 Transparency

The consultants encountered difficulty obtaining information directly from the JDA any information about its activities. The JDA does not appear to pursue a policy of public information.

Whereas the website states that there is a model Production Sharing Contract that the JDA will use, that model PSC wording has not been published. It would be useful to see the wording in order to understand the terms on which the JDA is working with companies and how production is shared.

The JDA website appears not to have been updated since May 2006.

Part 2: Upstream Mass Balance

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1 INTRODUCTION AND SCOPE OF REPORT

1.1 Objectives

The purpose of the report is to present the reconciliation of:

- i) individual shareholders' equity stake in the hydrocarbon streams
- ii) the amount of oil and gas produced with that used for calculating petroleum profit tax (PPT) and royalty payments
- iii) the amount of oil and gas used for PPT purposes as per operating companies records with those as per DPR records.

This report is structured to address these objectives for each of the hydrocarbon systems. There are separate sections dealing with:

- The reconciliation of Oil flows between Production Fields, Terminals and Liftings
- The Allocation of Production to Equity Owners

The Gas flows are treated in a separate section

1.2 Physical Audit Procedure

Following an initial meeting in May 2007, attended by most of the operating companies, on the 9th June 2007, requests for information on oil production and export volumes were issued to all companies who produced oil or gas during 2005. These requests included templates on which the data was to be reported. Similar templates were issued to DPR requesting details of export volumes they had fiscalised for each producing company.

Data availability from Covered Entities

- return of data was slow. Many templates were not returned until October or November, and we have yet to receive any data from Cavendish.
- With a number of 3rd parties using terminals operated by others, it is not possible to complete a terminal reconciliation until all parties using the terminal have provided data. This has impacted the reconciliation process significantly.
- DPR refused to provide data using the 2005 templates, which were an improvement over the 1999-2004 audit templates.

Reconciliation Issues

There was considerable variation between the operators about how the data was presented on templates. We attempted to acquire data that would create a gross mass balance. In reality we received data to create a Net balance.

- We had asked for production data derived from in-situ field records. Many companies provided field data back-calculated from Terminal data. To force the issue, we had attempted to acquire data on flow rates at flow stations. Whilst we still believe this raw data exists, most companies only provided us with volumetric data. And in most cases we suspect this has been derived by netting back from dry crude data.

- ❑ The companies interpreted the data requests in different ways and more effort needs to be put into the NEITI data definitions. Unfortunately some companies use the same terms in different ways. For example, where we had defined “Gross Receipts” into the Terminals as “the quantity of liquid arriving at the terminal (oil & water)”, some companies interpreted this as “The quantity of oil arriving at the terminal, prior to terminal adjustments.”
- ❑ There was an understandable confusion for those offshore terminals, where all processing is done on the FPSO, as to what data was required on the Production Template (P1.02) versus what was required for the Terminal Balance.
- ❑ The balance across the terminal requires an understanding of volumes flowing in, stock changes and volumes out. Furthermore, the allocation of production to owners, requires a knowledge of stocks attributable to each partner. The issue here is “Who holds this knowledge?” It is simple for the Terminal Operator to allocate stock to each partner within their own operation, but for 3rd parties using the terminal, all they can do is allocate stock to the 3rd party operation as a whole, not the individual participants within that 3rd party operation.

Since NNPC is a party to many ventures, this means it is entitled to amounts of stock from various inputs to a terminal.

Terminal Adjustments are made by Terminal operators to account for shrinkage (and sometimes spillage) that occurs at the terminal. Even nominally dry crude that sits in a tank suffers shrinkage from evaporation and the release of dissolved gases. To simplify the templates we had aggregated water separation (at the terminal) and shrinkage into one line item. With hindsight this was a simplification too far, since dewatering is a measurable quantity, but shrinkage is either calculated or estimated (SPDC applies a 0.1% terminal adjustment to all volumes).

- ❑ When assessing the volume of production liable to Royalty, it is not clear whether this should be done before or after applying terminal adjustments. Adjustments are applied on a month by month basis and appear to affect the notional stock applicable to each operation. We have therefore adopted the approach of calculating production entitlement Post-Terminal Adjustments.
- ❑ Reconciling cargoes to terminals was problematic. This is because the liftings by cargo data is only available from the F2.02.11 (Export volumes for PPT) template and the schedules that COMD provided. Unfortunately the latter was not provided in the correct format, so whilst they identified crude blend for each cargo, they did not specify the terminal at which the lifting occurred, and an additional mapping step was required in the analysis. In addition, reliance on the F2.02.11 template does not give a complete picture of liftings since it does not include liftings, for example, made by Service Contractors. The situation would have been much simpler had DPR provided the data initially requested (see below).

DPR

DPR could not provide lifting data by cargo. Despite the fact they witness and sign off every lifting. Had they done so, we would have been able to reconcile lifting volumes more easily and also it would have highlighted (apparent) anomalies, such as the handling of the MPNU unitisation production at Amenam and the AENR oil lifted from Brass.

DPR do not distinguish between Production (JV) from Lifting (company).

It is not clear whether the purpose of monthly production reconciliation undertaken by DPR is to agree the total volume produced, or to agree the allocation of entitlement to that production. The current process simply allocates production to each operator using a terminal – it does not allocate production to owners. This is particularly confusing where Unitisation Agreements are in place, and has led to some double-counting.

Given the complexity of many of the arrangements (PSCs, Carry Agreements, Unitisations etc.) it may not be practical to allocate production to individual equity owners on a monthly basis. However, it should be possible – and is desirable – for it to be done at least annually.

DPR do not distinguish NNPC liftings for export and domestic export. Since the proceeds from these liftings go to different places this would seem to be an important distinction to make.

Data Gaps

The 2005 audit did not attempt to gather detailed information on every step of the infrastructure. The intent was to gather meaningful independent data at two points (flow station and terminal) that could be reconciled. It has been successful in establishing the principle, but we have yet to get consistent use of in-situ field measurements.

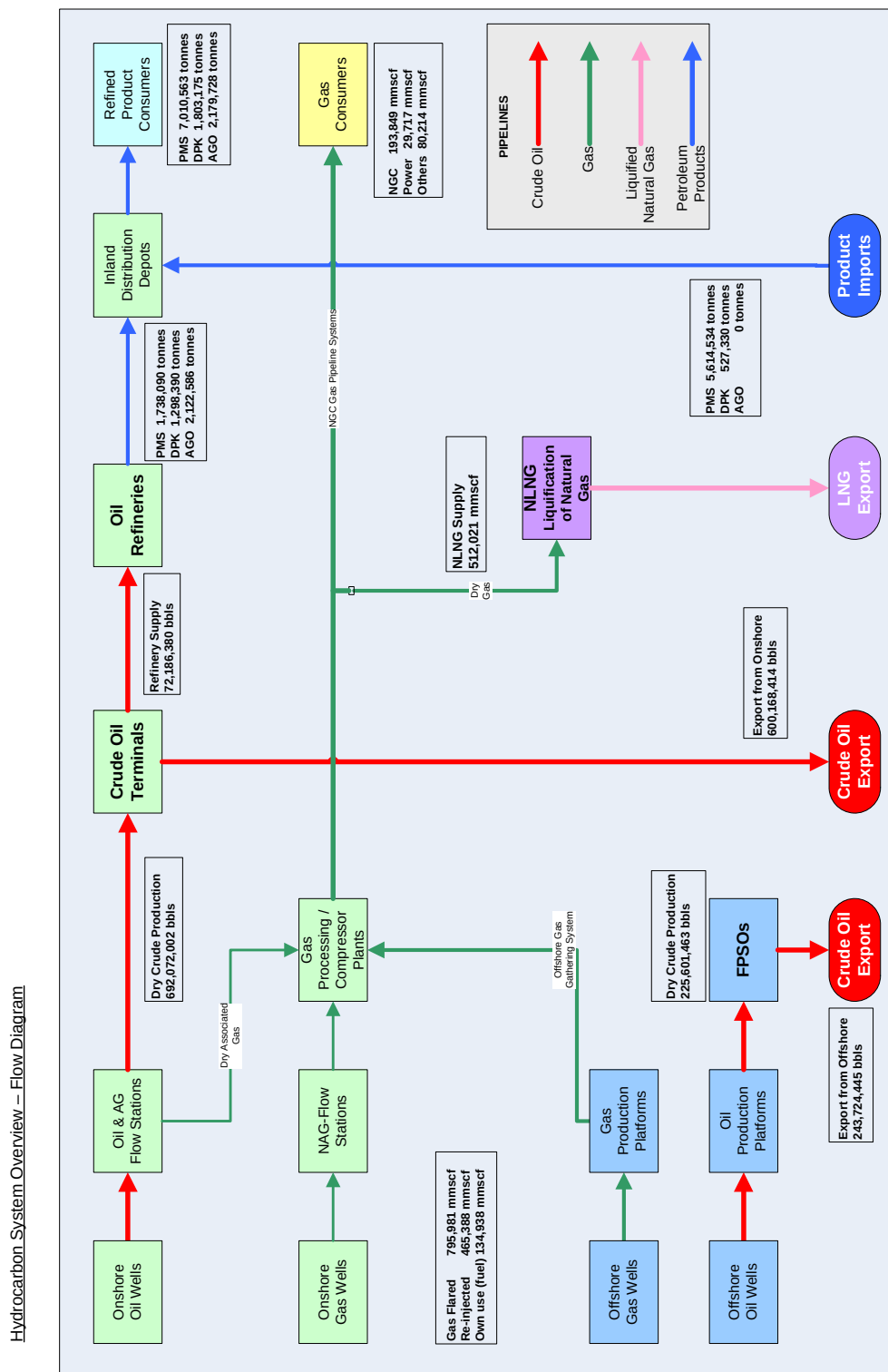
Given API data at flow stations, if water has been removed, there is the possibility to assess Royalty on flow station production rather than on terminal liftings. However, since in general more than one field flows into a flow station, this will remain an approximation.

Recommendations for 2006 audit:

- 1) Volumetric Templates should be redesigned to identify explicitly those data items that have been directly measured, those that have been estimated, and those that have been calculated.
- 2) Discussions should be held with Terminal Operator to clarify and agree:
 - o Definitions of gross liquids into terminal, de-watering, terminal adjustment etc.
 - o At what point does custody transfer from a producing company (JV) to a lifting company? And how to show this on the templates.
 - o Redesign template to show receipts from each Producer separately and be explicit about the identification of the lifters.
 - o Report Terminal Adjustments separately
 - o Require each Operator (including unitisation partners) to provide details of Stock Entitlement held at each terminal they use, allocated to each partner in their operation
- 3) Identify the processing point for gas flows from flow stations
- 4) For the Gas balance, re-introduce the distinction between gas lift and gas re-injection.

2 OVERVIEW OF HYDROCARBON SYSTEM FLOWS

2.1 Schematic Overview



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

2.2 Descriptive Overview of Hydrocarbon Flows

Upstream Oil

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

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

Offshore wells in deeper water are connected to Production Platforms, where gas is separated from the liquids (and possibly water from oil) and the liquids are then pumped to a Floating Storage and Offloading vessel (FSO). These are permanently moored tankers that store the crude oil ready to be exported. For some developments the FSO has the capability to process the liquids in addition to storage (FPSO) and the production platform can be dispensed with.

Upstream and Downstream Gas

Gas can occur either associated (mixed in) with the oil (AG) or as non-associated gas (NAG) where there is little or no oil present. Commercial development of gas resources is more complex than oil since it is not easily stored or transported. Nigeria does not yet have a large gas infrastructure and local demand for gas remains limited, hence there were few opportunities for the commercial exploitation of gas.

Some of the gas is required as fuel to operate the Flow Station and, in some fields, gas may be re-injected into a reservoir to maintain pressure and improve oil recovery. If there is no alternative commercial proposition, the remaining gas is flared.

Thus, NAG fields have only been exploited relatively recently, since the Nigerian Liquefied Natural Gas (NLNG) plant was built at Bonny and a number of Power Projects have come on-line. A limited amount of associated gas (AG) is used to supply NGC, the Nigerian Gas Company. This is piped directly to NGC if the pressure is high enough, or via compressors if necessary. Associated Gas is also used to produce LPG such as Propane and Butane.

Condensate is the name given to the clear oil produced from gas wells. Where this is found it is piped to a terminal, stored and exported separately from crude oil.

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

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

Crude Oil Supply to the Refineries

From onshore and shallow offshore wells the liquids are pumped through pipelines to the Oil Terminals. Some of the "dry" oil is pumped through fiscal meters to the Refineries where it is refined into products such as petrol and diesel. Small amounts of 'sour' crude oils are

imported for use in the Kaduna refinery for “lube oil” production; the Nigerian crude is classified as ‘sweet’.

Products Supply

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

2.3 Crude Oil System Overview

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

1) Reservoirs

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

2) Wells

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

3) Well Fluids

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

4) Flow-lines

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

5) Flow Stations and Production Platforms

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

6) Pipelines

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

7) Oil Terminals:

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

The Terminal Operator is usually the operator of the first field to be developed in the area (the table below details the Operators of the 16 export terminals in use during 2005). Under the original JVs the operator was a nominated partner in the JV and developed and operated both fields and terminals for the JV. Individual partners are entitled to lift their share of oil and the terminal operator must keep track of “entitlement stock” for each lifter.

As more fields are developed and make use of the existing infrastructure, agreements are put in place for the terminal to handle product on behalf of 3rd parties. Furthermore, the partner companies in these 3rd party operations may or may not also participate in the original JV that built the terminal.

This potentially gives rise to a great deal of confusion, and it is important to make clear distinction between individual companies and JVs [Where historically it was customary to refer to Shell, SPDC and the SPDC JV interchangeably. Today that simply leads to confusion]

So for example:

- the Bonny Terminal is operated by SPDC on behalf of the SPDC JV (a Joint Venture between SPDC, NNPC, EPNL and NAOC). The entitlement to production by that JV is shared between the JV partners according to the JV agreement. In addition, the terminal handles product for NDPR (a small independent operator) and EPNL JV (joint venture between EPNL and NNPC). Furthermore, one field is subject to a Unitisation Agreement with CNL JV (joint venture between CNL and NNPC).

Thus, the Terminal Operator must keep track of production from 3(4) different partnerships and track the entitlement to lift product from six different companies.

- Similarly, Brass Terminal, operated by NAOC on behalf of the NAOC JV (partners: NAOC, NNPC and Phillips) additionally receives product from AENR (another subsidiary of Agip the owner of NAOC), Addax PSC and CNL JV. Also there are four fields operated by NAOC JV that have unitisation agreements with SPDC JV.

Thus there are (potentially) seven companies entitled to lift from Brass.

Additionally, companies may trade their entitlements rather than lift them, or assign their entitlements in settlement of other transactions between them. Some entitlements are too

small to be commercial to lift and these are commonly sold to another party before lifting. For such reasons, the amounts actually lifted by a company may differ from the lifting entitlement.

At the end of 2005 there were the following seventeen oil export terminals in Nigeria.

OPERATOR	LOCATION	Offshore vessel
NAOC	Brass	(onshore)
CNL	Escravos	(onshore)
MPNU	Qua Ibo	(onshore)
SPDC	Bonny	(onshore)
SPDC	Forcados	(onshore)
Addax	Antan	Knock Taggart
Addax	Okwori*	Sendje Berg*
Amni	Ima	Ailsa Craig
CNL	Oloibiri	Pennington
Cavendish	Obe	Crystal Sea
Express/SEPCOL	Ukpokiti	Trinity Spirit
MPNU	Yoho	Falcon
NAE	Abo	Gray Warrior
NPDC/AENR	Okono	Mystras
SPDC	EA	Sea Eagle
SNEPCO*	Bonga*	Bonga*
EPNL	Odudu	Unity

*commenced during 2005

All these exports points have their own fiscalised metering systems. In addition, 3rd party inputs to these terminals are fiscalised prior to injection.

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

8) Metering & Fiscalisation

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

Measurements in the Flow Stations etc. are less accurate because they are used for field control reasons only. Typical accuracy for Field meters is +/-10%.

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

9) Contractual arrangements for development, production and sale

In Nigeria there are four commonly used types of development arrangement: a Joint Venture (JV), a Production Sharing Contract (PSC), a Service Contract (SC) and a Sole Risk (SR).

Joint Venture (JV): the development of an acreage block is awarded to a joint venture between NNPC and one or more Oil Companies. All exploration and production costs are shared, each partner is liable to pay Royalties and Petroleum Profit Tax (PPT) in proportion to its interest in the JV. And each would pay company income tax on any profits from gas sales.

Production Sharing Contract (PSC): NNPC owns the acreage and awards a contract to a company (the contractor) to carry out petroleum operations on behalf of NNPC. The contractor provides all necessary finance and bears all related risks; the operating costs are recovered from production. Oil is given to NNPC to sell to cover liabilities for Royalty and PPT. NNPC and the contractor share any remaining oil.

Service Contract: NNPC owns the acreage and contracts with a service contractor to develop and operate the acreage. The Service contractor may be paid in oil to recover costs (and make a profit). NNPC is liable to PPT and Royalty payments. The Service Contractor would be liable to pay Company Income Tax on profits.

Sole Risk: NNPC has no interest in the acreage (unless the Sole Risk licence is held by NPDC, which is NNPC's wholly owned development company). All taxes are payable by the Sole Risk contract holder.

In addition, the following contractual variations exist:

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

Carry agreement: this is a form of alternative financing. One party (usually NNPC) will be 'carried' in the sense that their share of financing costs is borne by other parties. These other parties are entitled to recover the additional financing costs through production.

10) Third Party Oil

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

As the number of marginal fields on-stream increases, and as the Nigerian Oil Sector becomes more complex, there will be increased quantities of 3rd party oil to be handled. This will require more sophisticated and more transparent systems to be put in place.

3 UPSTREAM VOLUMETRIC RECONCILIATION

3.1 Introduction

In this section, we discuss key methodological issues concerning the volumetric reconciliation and its relation to company-level production entitlements.

The physical reconciliation has three components:

- Production and Terminal balance including stock changes
- Export reconciliation
- Allocation of production to participating equity interests

Technical and Commercial issues arise in each.

3.2 Mass balance methodology

The 1999-2004 audit report discussed in detail the difference between a Gross Oil Balance and a Net Oil Balance. Briefly the net oil balance is derived from the allocation of terminal data back to individual fields, whereas a gross balance seeks to quantify all causes of loss (leakage, shrinkage, theft etc.) throughout the system.

The challenges in creating a comprehensive Gross Balance were discussed in depth in the 1999-2004 report. The main technical difficulty being to measure multi-phase flows at the wellhead. The intention of the 2005 Audit was to create a simplified Gross Volumetric Balance, by reconciling measured data from Terminal Operators to measured data from Field Operators and to liftings data from Lifters.

The producing companies were requested to provide monthly data to enable a "Gross Liquid Mass Balance" to be compiled. They were requested to show, for each Flow Station (from records of measurements at the flow station):

- 1) The Average flow rate of liquids into the flow station each month (this would normally be a mixture of oil water and gas)
- 2) The volume of any 3rd party additions at the flow station (normally this would be dry crude)
- 3) The volume of water removed at the flow station
- 4) The volume of liquids passed on from this flow station (this may be oil and water) – and identify the next processing point or terminal.
- 5) The quantity of gas flared
- 6) The quantity of gas passed on (if the gas is used) and where the next gas processing point is.

Theoretically, aggregating this information across all producers will give the total of liquids entering the system. Though there are a number of limitations and caveats:

- 1) We recognise that measurement at the wellhead is largely impractical. Hence any losses between the wellhead and the flow station would not be detected.
- 2) Field meters are not very accurate (+/-10%). There is debate about whether the inaccuracy is random – i.e. over a large number of measurements the average reading would be correct. Or whether there are systemic inaccuracies – i.e. particular flow conditions may cause a meter consistently to over/under measure.

At the other end of the system, the Terminal Operators were requested to provide the following data:

- 1) Opening Stock at Jan 1/05.
- 2) Monthly Gross Receipts (i.e. total liquids arriving at the Terminal during the month)
- 3) Total de-watering/terminal adjustments applied
- 4) Total Liftings during the month
- 5) Closing stock each month

Aggregating this data across all terminals, theoretically allows us to calculate the total liquids leaving the system at the end point. And a comparison between the production data and the terminal data would quantify the total losses in the system (although it would not identify the cause of the loss).

In addition, the Terminal Operators were asked to allocate stocks, production and liftings across the beneficial owners of the oil. This also required us to know if there were any “crude swaps” – where one entitled lifter chose to lift their entitlement at a different terminal and “swap” it. This data compared to the liftings schedules provided by each lifter enables us to reconcile export and terminal supply volumes that are (currently) used for PPT calculations.

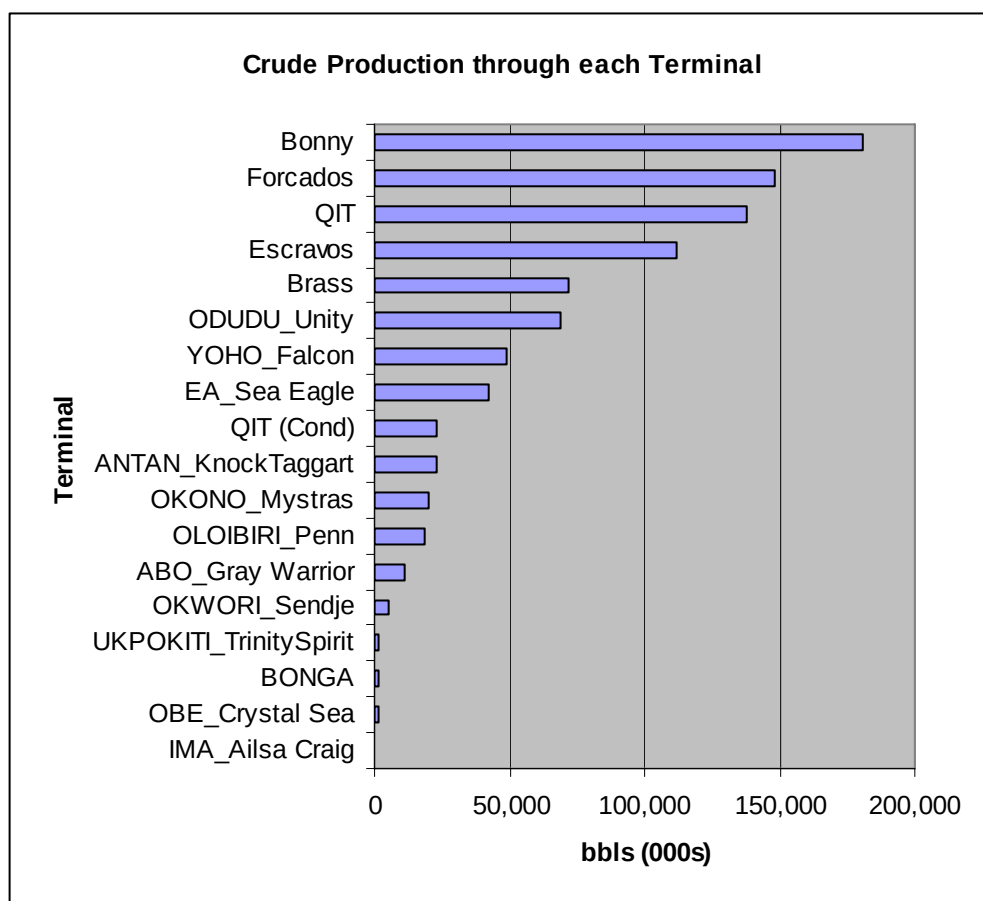
3.3 Overview of Crude Production and Export crude liftings Reconciliation

The data substantially agreed between DPR and Companies. Since the 1999-2004 Audit, DPR now holds regular reconciliation meetings with Terminal Operators, Producers and Lifters. Whilst the aggregate for export liftings agrees between parties, overall DPR reported 606,803bbbls production more than the Terminal Operators. Given that no DPR reconciliation was done on Bonga (which commenced production only in November/December 2005), that actual difference on Production is 2,078,637bbbls. This is made up of approximately 1,000,000bbbls at each of Brass Terminal and Bonny Terminal. At Bonny the difference is accounted by DPR double counting the Belema Unitisation volume in both CNL and SPDC production. At Brass the source of the difference is unclear, but clearly relates to NAOB production, not 3rd parties using the terminal. Overall the difference is less than 1% of production.

DPR records are maintained principally in terms of the total amounts lifted from each terminal per vessel. They are supported by Bill of Lading. The DPR records are designed to keep full details of the fiscalised export quantities. However, the beneficial ownership of a cargo seems not to be of equal importance to DPR. This meant that, whereas the absolute volumes exported from each terminal materially agreed in total, there were instances where the ownership of the oil differed. One particular issue remains unresolved between PanOcean and NNPC at Forcados where DPR have not recognised that NNPC overlifted during 2005 to compensate for an underlift during 2004.

Summary of Production and Liftings by Terminal

Operator	Terminal	Crude Production	Crude Liftings	Stock change	DPR Production	gain/(loss)
ADDAX	ANTAN_KnockTaggart	22,993,564	-23,254,793	-261,229	22,995,566	2,002
ADDAX	OKWORI_Sendje	5,325,252	-4,541,678	783,574	5,340,638	15,386
Amni International	IMA_Ailsa Craig	831,995	-775,426	56,569	770,713	-61,282
Cavendish	OBE_Crystal Sea	1,408,276	-1,478,000	-69,724	1,408,276	0
CNL	Escravos	111,818,177	-111,448,483	369,694	111,821,154	2,977
CNL	OLOIBIRI_Penn	18,713,493	-19,032,413	-318,920	18,731,060	17,567
EPNL	ODUDU_Unity	69,055,772	-69,400,989	-345,217	69,056,104	332
MPNU	QIT	137,754,519	-137,994,015	-239,496	137,670,857	-83,662
MPNU	QIT (Cond)	23,082,735	-23,032,989	49,746	23,082,734	-1
MPNU	YOHO_Falcon	49,115,139	-48,712,543	402,596	49,115,159	20
NAE	ABO_Gray Warrior	11,315,200	-11,773,311	-458,111	11,315,648	448
NAOC	Brass	71,877,322	-72,446,058	-568,736	72,944,037	1,066,715
NPDC/AENR	OKONO_Mystras	19,903,197	-19,916,922	-13,725	19,908,906	5,709
Shebah (SEPCOL)	UKPOKITI_TrinitySpirit	1,803,030	-1,926,828	-123,798	1,821,794	18,764
SNEPCO	BONGA	1,471,834	-196,821	1,275,013	0	-1,471,834
SPDC	Bonny	180,689,483	-179,653,010	1,036,473	181,601,977	912,494
SPDC	EA_Sea Eagle	42,439,486	-42,715,147	-275,661	42,439,488	2
SPDC	Forcados	148,136,273	-147,780,239	356,034	148,256,157	119,884
TOTAL		917,734,747	-916,079,665	1,655,082	918,280,268	545,521



Note: No data has been received from Cavendish, so the figures quoted in the table above are from DPR records.

The tabulated figures differ slightly from those reported elsewhere in this report. As shown in section 4.1, there are some small unresolved differences at Forcados and Bonny between liftings reported by Terminal Operators and liftings reported by lifters.

4 Analysis of Net Oil Balances and Gross Volumes Mass Balances

Summaries of the reconciliations of the gross balances at each terminal are set out below. Data for each terminal is presented as follows:

- Production data as reported on P1.02 templates (with additional sections added for 3rd party injections if applicable).
- Terminal Balance (total receipts, liftings, terminal dewatering and stock change)
- Liftings data (as reported by the terminal operator, reconciled to data provided by each individual lifter)

Bonny Terminal		Operator: SPDC	
Source	Production (P1.02)		
CNL (excl Belema)	Gross production	Field De-Watering	Liquids Passed
NPDR (Ogbelle)	18,711,441	-4,501,059	14,210,382
EPNL	24,999,304	-14,403,854	10,595,450
	Total 3rd Party		24,935,394
	gain/(loss)		517,356 from 3rd party to SPDC
	3rd Party Production Data. Injections into SPDC infrastructure		
SPDC (Belema)	Gross production	Field De-Watering	Liquid passed on
SPDC (NPDR)	236,750,400	0	236,750,400
SPDC (CNL Inda)	SPDC Production data, including 3rd party additions		148,046
SPDC (CNL Robert)			5,025,578
SPDC (EPNL)			9,684,040
			10,595,086
			262,203,150
			517,356
	DPR allocation of fiscalised crude to producers		
	Reconciliation between production data and Terminal Balance		
	gain/(loss)		0
SPDC	Terminal Balance		
SPDC	Gross Receipts	262,203,150	
SPDC	De-water	-81,514,667	
SPDC	Dry Crude	180,689,483	
SPDC	Total Liftings	-179,653,010	-179,653
SPDC	Stock Change	1,038,473	
SPDC	gain/(loss)	2,000	
	DPR Fiscalised Crude		
CNL	15,102,314		
NPDR	141,014	11,452	
EPNL	10,587,628	-7,822	
SPDC	155,471,021		
	181,601,977	912,494	
SPDC	Liftings (per Terminal Operator)		
SPDC	NNPC	81,674,579	81,675
SPDC	SPDC	46,383,711	46,384
SPDC	EPNL	15,684,074	15,684
SPDC	CNL JV	8,974,960	8,975
SPDC	CNL JV	15,886,895	15,887
SPDC	EPNL JV	10,998,791	10,999
SPDC	NPDR	50,000	50
SPDC	Total 3rd party	26,935,686	26,936
			179,653
	Reconciliation of 3rd Parties		
	CNL JV	EPNL JV	Total
	0,272	6,297	97,255
	0,272	6,297	46,384
	2		20,376
			8,975
			6,614
			0
	9		0
			50
			179,653
	0	0	179,653
	Difference between liftings reported by terminal operator and lifters		
	gain/(loss)		36
COMD	Liftings (per Lifter F2.02.12)		
COMD	NNPC (Export)	43,973,437	43,973
COMD	NNPC (Dom Export)	21,779,297	21,779
COMD	NNPC (PHRC)	31,537,386	31,537
SPDC	Liftings from terminal as reported by Lifting Companies		46,384
EPNL			20,376
NAOC			8,975
CNL			6,614
NPDR			50
			179,689
	DPR Reconciliation		
	NNPC (export)	65,753	0
	NNPC (refinery)	31,500	-38
	SPDC	46,384	0
	EPNL	20,376	0
	NAOC	8,975	0
	CNL	6,614	0
	NPDR	50	0
		179,651	-38

4.1 Bonny Terminal

Bonny is operated by SPDC and handles product produced by SPDC(JV), CNL(JV), EPNL(JV) and NPDR. All these are fiscalised dry crude feeds into Bonny. There are two injection points for CNL(JV) – Inda and RobertKiri. A further complication is that Belema N field is a unitisation agreement between SPDC(JV) and CNL(JV).

Observations:

Bonny Terminal

Operator: SPDC

Source

Production (P1.02)		
Gross production	Field De-Watering	Liquids Passed
CNL (excl Belema N)	18,711,441	-4,501,059
NPDR (Ogbelle)		129,562
EPNL	24,999,304	-14,403,854
	Total 3rd Party	24,935,394

gain/(loss) 517,356 from 3rd party to SPDC

	Gross production	Field De-Watering	Liquid passed on	Reconciliation to 3rd party
SPDC (inc Belema N)	236,750,400	0	236,750,400	
SPDC (NPDR)	148,046		148,046	18,484 (NPDR omitted Oct Prod)
SPDC (CNL Inda)	5,025,578		5,025,578	499,236
SPDC (CNL RobertKiri)	9,684,040		9,684,040	
SPDC (EPNL)	10,595,086		10,595,086	-364
			262,203,150	517,356

gain/(loss) 0

SPDC

SPDC

SPDC

SPDC

SPDC

SPDC

SPDC

Terminal Balance		
	Gross Receipts	262,203,150
	De-water	-81,513,667
	Dry Crude	180,689,483
	Total Liftings	-179,653,010
	Stock Change	1,038,473
	gain/(loss)	2,000

DPR Fiscalised Crude		gain/(loss)
CNL	15,102,314	-14
NPDR	141,014	-7,032
EPNL	10,587,628	-7,822
SPDC	155,771,021	927,362
	181,601,977	912,494

				Reconciliation of 3rd Parties		
Liftings (per Terminal Operator)		bbl	bbl (000s)	CNL JV	EPNL JV	Total
SPDC	NNPC	81,674,579	81,675	9,273	6,307	97,255
SPDC	SPDC	46,383,711	46,384			46,384
SPDC	EPNL	15,684,074	15,684		4,692	20,376
SPDC	NAOC	8,974,960	8,975			8,975
(CNL)	(CNL)			6,614		6,614
SPDC	CNL JV	15,886,895	15,887	-15,887		0
SPDC	EPNL JV	10,998,791	10,999		-10,999	0
SPDC	NPDR	50,000	50			50
SPDC	Total 3rd party	26,935,686				
			179,653	0	0	179,653

gain/(loss) 36

Liftings (per Lifter F2.02.12)				DPR Reconciliation		gain/(loss)
COMD	NNPC (Export)	43,973,437	43,973	NNPC (export)	65,753	0
COMD	NNPC (Dom Export)	21,779,297	21,779	NNPC (refinery)	31,500	-38
COMD	NNPC (PHRC)	31,537,386	31,537	SPDC	46,384	0
SPDC	SPDC			EPNL	20,376	0
EPNL	EPNL	20,375,640	20,376	NAOC	8,975	0
NAOC	NAOC			CNL	6,614	0
CNL	CNL	6,614,103	6,614	NPDR	50	0
NPDR	NPDR					
			179,689		179,651	-38

SPDC does not de-water supplies into Bonny until they reach the terminal.

SPDC report 517,356 bbl more crude arriving in Bonny from 3rd parties than is reported by the 3rd parties. This comprises 18,484 due to NPDR who under-reported their production in

October (the 1st month of production) and the balance is largely a discrepancy with CNL (499,236bbls).

This is significant since it is a fiscalised crude stream having been measured at the injection points to the Shell infrastructure. A month-by-month comparison highlights the differences reported by each company.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SPDC	1,390,404	1,209,712	1,322,904	1,233,739	1,305,849	1,241,696	1,166,529	1,246,196	1,198,646	1,113,192	1,073,135	1,207,616
CNL	1,387,183	1,207,154	1,318,996	1,229,771	1,302,172	1,237,769	1,127,573	1,117,186	1,032,454	1,000,405	1,046,174	1,203,545
Diff	3,221	2,558	3,908	3,968	3,677	3,927	38,956	129,010	166,192	112,787	26,961	4,071

There is also a discrepancy of 912,494bbls between the DPR fiscalised production record and the producers figures. Most of this (891,946bbls) is due to DPR double counting the CNL share of the Belema Unitisation, which appears to have been included in both CLN JV and SPDC JV production.

Reconciliation of liftings:

The terminal operator reports liftings by each 3rd party JV, and individually for each partner in the SPDC JV. We have reconciled the liftings stated by the Terminal Operator to the liftings stated by each lifting company. All values agreed except the COMD Liftings for refinery supply where COMD declared 38,000 bbls more were supplied to PHRC than declared by the Terminal Operator.

4.2 Brass Terminal

Brass is operated by NAOC and handles product produced by NAOC(JV), CNL(JV), Addax and AENR. In addition, there are four fields with unitisation agreements between NAOC(JV) and SPDC(JV). NAOC is the operator for these and the members of the SPDC(JV) are entitled to lift product there. Addax receives wet crude from the CNL(JV) Jisike field at Izombe, where water is separated for both Addax and CNL production. These flows are commingled and fed to Brass.

Brass Terminal		Operator: NAOC	
Source	Production (P1.02)		
	Gross production	Field De-Watering	Liquid passed on
NAOC	99,513,967	0	99,793,187
AENR	5,147,729	-768,245	4,379,484
ADDAX (inc CNL)	9,898,297	-7,064,850	2,871,333
CNL (Jisike)	1,907,709	-330,817	1,576,892
Addax (excl CNL)	7,990,588	-6,734,033	1,294,441
			107,044,004
	gain/(loss)	2,217,441	
	DPR Fiscalised Crude		
	NAOC	65,713,942	1,087,437
	AENR	4,379,484	0
	CNL	1,576,892	0
	ADDAX	1,273,719	-20,722
		72,944,037	1,066,715
	Terminal Balance		
NAOC	Gross Receipts	109,261,445	
NAOC	De-water	-37,384,123	
NAOC	Implied Crude	71,877,322	bbl (000s)
NAOC	Total Liftings	-72,446,058	-72,446
NAOC	Stock Change	-568,736	
	gain/(loss)	0	
	Reconciliation to Company Liftings		
	Liftings (per Terminal Operator)	bbl	bbl (000s)
NAOC	NNPC	37,152,589	37,153
NAOC	AENR (NNPC)	4,139,369	4,139
NAOC	NAOC	12,103,931	12,104
NAOC	ADDAX (inc CNL)	2,729,641	2,730
NAOC	PHILLIPS	12,056,612	12,057
(EPNL)	(EPNL)		
NAOC	SPDC (JV)	4,263,916	4,264
		72,446,058	72,446
	gain/(loss)	3	
	DPR Reconciliation		
COMD	NNPC	43,837,038	43,837
COMD	NNPC (Dom Exp)	949,576	950
AENR	AENR	1,562,192	1,562
NAOC	NAOC		12,354
Addax	ADDAX		790
Phillips	PHILLIPS		12,057
EPNL	EPNL		899
	Total	72,449	72,446
	gain/(loss)	-3	

Observations:

AENR is a Service Contractor to NNPC for the Agbara Field. As such it is not responsible for paying PPT or Royalty on production, hence they did not provide details of liftings on the F2.02.12 template. However, we've have received a separate notification of the cargos AENR lifted to their own account from Brass.

NAOC does not de-water its production at flow stations (except at the Ebocha Gas Plant – though they provided no details of the quantities of water removed there), so it's flows into Brass are a mixture of oil and water. All 3rd party injections into the Brass system are fiscalised dry crude quantities.

The Addax and CNL feeds are co-mingled.

NAOC report terminal receipts 2.27mmbbls greater than the aggregate of the inputs per P1.02 templates. At 2% of gross volume, this could be due to metering inaccuracies and is well within the tolerances for field metering.

Escravos is operated by CNL for the CNL(JV). In addition it handles 3rd party product for Dubri and Conoil. All feeds into Escravos are dry crude.

All production into Escravos is de-watered at the flow stations.

4.4 Forcados Terminal

Forcados is operated by SPDC and handles 3rd party feeds for NPDC, PanOcean(JV) and NAOC(JV). There are two injection points for NPDC – Abura and through the PanOcean injection point.

COMD lifts all product on behalf of NNPC, NPDC and PanOcean.

Forcados Terminal				Operator: SPDC		
Source	Production (P1.02)					
	Gross production	Field De-Watering	Dry Crude	gain/(loss)		
NPDC (Abura)	1,588,821	-535,711	1,161,762	108,652		
NPDC (PanO injection)	1,141,351	-238,240	954,646	51,535		
PanOcean	10,086,536	-1,352,614	8,640,354	-93,568		
NAOC			2,167,843			
	Total 3rd Party		12,924,605			
	gain/(loss)		126,520	from 3rd party to SPDC P1.02		
	Gross production	Field De-Watering	Liquid passed on			
SPDC (inc Abura)	321,900,897	0	321,900,897			
SPDC (NAOC)	2,167,842		2,167,842	-1		
SPDC (PanO/NPDC)	9,721,521		9,721,521	126,521		
			333,790,260			
	gain/(loss)		618,428			
	DPR Fiscalised Crude					
			gain/(loss)			
	NPDC (total)	2,115,928	-480			
	PanOcean	8,759,858	119,504			
	NAOC	2,139,297	-28,546			
	SPDC	135,241,074	-1,114			
	Total	148,256,157	89,364			
	Terminal Balance					
SPDC	Gross Receipts	334,408,688				
SPDC	De-water	-186,230,129				
SPDC	Dry Crude	148,166,793				
SPDC	Total Liftings	-147,780,239	-147,780			
SPDC	Stock Change	386,554				
SPDC	gain/(loss)	0				
	Reconciliation of 3rd Parties					
Liftings	Liftings (per Terminal Operator)	bbl	bbl (000s)	PanOcean JV	NAOC JV	Total
SPDC	NNPC		73,418	5,778	929	80,125
SPDC	SPDC		41,440			41,440
SPDC	EPNL		12,771			12,771
SPDC	NAOC		6,649		646	7,295
PHILL	(Phillips)				591	591
SPDC	PanOcean (JV)	8,989,072	8,989	-5,778		3,211
SPDC	NAOC (JV)	2,165,708	2,166		-2,166	0
SPDC	NPDC	2,347,531	2,348			2,348
SPDC	Total 3rd party	13,502,311				
			147,780	0	0	147,780
	gain/(loss)		23			
	DPR Reconciliation					
			gain/(loss)			
COMD	NNPC (Export)	55,358,779	55,359			
COMD	NNPC (Dom Export)	23,260,929	23,261			
COMD	NNPC (PPMC Excha	947,628	948	NNPC (export)	79,183	-385
COMD	NNPC (KRPC)	520,742	521	NNPC (refinery)	507	-13
COMD	NPDC	2,407,400	2,407	NPDC	2,397	-10
COMD	PanOcean	3,211,052	3,211	PanOcean	3,596	385
SPDC	SPDC	41,440	41,440	SPDC	41,440	0
EPNL	EPNL	12,771	12,771	EPNL	12,771	0
NAOC	NAOC	7,295	7,295	NAOC	7,295	0
PHILL	Phillips	591	591	Phillips	591	0
PAN		147,803	147,803		147,780	-23

Observations

Liftings

There appears to be a misallocation in the DPR liftings reconciliation of the 385,000bbbls between PanOcean and NNPC. This is caused by a misallocation of revenues during 2004

that has been recovered by NNPC lifting in excess of its 60% share in 2005. This has not been recognised by DPR in its reconciliation of liftings.

There is a difference of 126,521 bbls (1%) between the production claimed by the 3rd parties and that claimed to be received by SPDC. It is not possible to isolate the cause of this since the SPDC data aggregates the NPDC/PanOcean injections.

4.5 Olibiri/Pennington Terminal

Oloibiri is operated by CNL. In addition to CNL(JV) product, Continental Oil and Gas (CONT) feed dry crude into Oloibiri.

OLOIBIRI/Pennington				Operator: CNL	
Source	Production (P1.02)				
	Gross production	Field De-Watering	Liquid passed on	gain/(loss)	
CNL	12,404,282	-6,902,381	5,501,901		0
CONT	17,098,985	-3,904,680	13,242,750	48,446	
			18,744,651	48,446	
	gain/(loss)		29,831		
	Terminal Balance				
CNL	Gross Receipts	18,774,482			
CNL	De-water/Shrinkage	-60,989			
CNL	Implied Crude	18,713,493			
CNL	Total Liftings	-19,032,413		-19,032	
CNL	Stock Change	-318,920			
CNL	gain/(loss)	0			
	DPR Fiscalised Crude				
	CNL	5,488,311			
	CONT	13,242,749			
		18,731,060		17,567	
	Liftings (per Terminal Operator)				
		bbl	bbl (000s)		
CNL	NNPC	2,843,270	2,843		
CNL	CNL	1,898,042	1,898		
CNL	CONT	14,291,101	14,291		
			19,032		
	gain/(loss)		-42		
	Liftings (per Lifter F2.02.12)				
COMD	NNPC	1,894,472	1,894		
COMD	NNPC (Dom Exp)	906,846	907	2,843	42
CNL	CNL	1,898,042	1,898	1,898	
CONT	CONT		14,291	14,291	
			18,990	19,032	42
	DPR Reconciliation				gain/(loss)

4.6 Qua Ibo Terminal (and QIT Condensate)

QIT and the Qua Ibo Condensate terminal are operated by MPNU.

QUA IBO Terminal Operator: MPNU

Source	Production (P1.02)			
MPNU	Gross production	Field De-Watering	Liquid passed on	
	174,049,513		174,484,995	
	gain/(loss)		-5,280,620	(3% shrinkage from offshore to terminal)
MPNU	Terminal Balance			DPR Fiscalised Crude
MPNU	Gross Receipts	169,204,375		
MPNU	De-water	-31,449,856		
MPNU	Implied Crude	137,754,519		MPNU 137,670,857
MPNU	Total Liftings	-137,994,015	-137,994	-83,662
MPNU	Stock Change	-239,496		
MPNU	gain/(loss)	0		
Liftings	Liftings (per Terminal Operator)			
MPNU		bbl	bbl (000s)	
MPNU	NNPC	82,414,899	82,415	
MPNU	MPNU	55,579,116	55,579	
			137,994	
	gain/(loss)		0	
Lifters F2.02.12	Liftings (per Lifter F2.02.12)			
COMD	NNPC (Dom Export)	16,974,035	16,974	
COMD	NNPC (PPMC Exch)	950,400	950	
COMD	NNPC (Export)	64,490,464	64,490	NNPC 82,415
MPNU	MPNU		55,579	MPNU 55,579
			137,994	137,994

QUA IBO (Condensate) Terminal Operator: MPNU

Source	Production (P1.02)			
MPNU	Gross production	Field De-Watering	Liquid passed on	gain/(loss)
	22,769,345	-1,380,995	22,833,258	1,444,908
	gain/(loss)		249,477	
MPNU	Terminal Balance			DPR Fiscalised Crude
MPNU	Gross Receipts	23,082,735		
MPNU	De-water			
MPNU	Implied Condensate	23,082,735		MPNU 23,082,734
MPNU	Total Liftings	-23,032,989	-23,033	-1
MPNU	Stock Change	51,727		
MPNU	gain/(loss)	1,981		
MPNU	Liftings (per Terminal Operator)			
MPNU		bbl	bbl (000s)	
MPNU	NNPC	13,883,963	13,884	
MPNU	MPNU	9,149,026	9,149	
			23,033	
	gain/(loss)		0	
COMD	Liftings (per Lifter F2.02.12)			
COMD	NNPC (Export)	12,977,117	12,977	
COMD	NNPC (Dom Exp)	906,846	907	NNPC 13,885
MPNU	MPNU		9,149	MPNU 9,149
			23,033	23,034
	gain/(loss)			1

Observations:

MPNU have made efforts to report field measurement (as requested) rather than net back values from the terminal. This is why there are substantial differences between field reported figures and the terminal data. However, these data are still within the tolerances to be expected of field meters (<10% error).

4.7 FPSO KnockTaggart

Knock Taggart is operated by Addax and also handles 3rd party crude from MoniPulo. MoniPulo product is processed in field and exported as dry crude to Knock Taggart.

ANTAN/Knock Taggart

Operator: ADDAX

Source	Production (P1.02)			
	Gross production	Field De-Waterin	Liquid passed on	gain/(loss)
ADDAX	27,795,912	0	28,139,421	343,509
MONI	11,226,235	-5,441,606	5,794,198	9,569
			33,933,619	353,078
			gain/(loss)	-77,000
	Terminal Balance			DPR Fiscalised Crude
ADDAX	Gross Receipts	33,856,619		ADDAX 17,201,368
ADDAX	De-water	-10,863,055		MONI 5,794,198 gain/(loss)
ADDAX	Implied Crude	22,993,564		22,995,566 2,002
ADDAX	Total Liftings	-23,254,793	-23,255	
ADDAX	Stock Change	-259,232		
ADDAX	gain/(loss)	-46,507,589		
	Liftings (per Terminal Operator)			
		bbl	bbl (000s)	
ADDAX	NNPC	8,719,233	8,719	
ADDAX	ADDAX	8,553,428	8,553	
MONI	Moni Pulo	5,982,132	5,982	
			23,255	
			gain/(loss)	0
	Liftings (per Lifter F2.02.12)			Liftings (per DPR data)
COMD	NNPC	8,719,233	8,719	NNPC 8,719
ADDAX	Addax	8,553,428	8,553	Addax 8,553
MONI	Moni Pulo		5,982	Moni Pulo 5,982
			23,255	23,255
				gain/(loss) 0

4.8 FPSO Mystras

Mystras is operated by AENR under a service contract to NPDC.

OKONO/Mystras				Operator: NPDC/AENR	
Source	Production (P1.02)				
AENR	Gross production	Field De-Watering	Liquid passed on	gain/(loss)	
	19,919,089	-10,183	19,908,906		0
	gain/(loss)				0
	Terminal Balance			DPR Fiscalised Crude	
AENR	Gross Receipts	19,908,906			
AENR	De-water	-5,709			
AENR	Implied Crude	19,903,197		AENR	19,908,906
AENR	Total Liftings	-19,916,922	-19,917		gain/(loss)
AENR	Stock Change	-13,725			5,709
AENR	gain/(loss)	0			
Liftings	Liftings (per Terminal Operator)			bbl	bbl (000s)
AENR	NNPC	12,969,213	12,969		
AENR	AENR	6,947,709	6,948		
			19,917		
	gain/(loss)			-1,446	(COMD omitted NPDC liftings in November)
COMD	Liftings (per Lifter F2.02.12)			DPR Reconciliation	
AENR	NPDC	11,522,988	11,523	NPDC	12,969
	AENR		6,948	AENR	6,948
			18,471		19,917

Observations:

The COMD schedule of liftings, omitted four cargoes (lifted in November) due to the NPDC account amounting to some 1,446,000 bbls. These liftings have been confirmed by both AENR, the terminal operator and NPDC.

DPR identify AENR as the owner of the Fiscalised production. This should be NPDC since AENR is only a service contractor. NPDC is liable for Royalty and PPT payments for the total production.

4.9 FPSO Sea Eagle

EA/Sea Eagle is operated by SPDC. This is a self-contained operation with no 3rd party involvement and all processing handled on the FPSO (no data was provided by SPDC for field production).

EA/Sea Eagle		Operator: SPDC				
Source	Production (P1.02)					
	Gross production	Field De-Watering	Liquid passed on	gain/(loss)		
SPDC	47,186,246	-4,471,099	42,715,147	0		
SPDC	Terminal Balance			DPR Fiscalised Crude		
	Gross Receipts	46,910,585		SPDC	42,439,488	
	De-water	-4,471,099				gain/(loss)
	Implied Crude	42,439,486				2
	Total Liftings	-42,715,147	-42,715			
	Stock Change	-275,661				
gain/(loss)	0					
SPDC	Liftings (per Terminal Operator)			bbl	bbl (000s)	
	NNPC	11,366,628	11,367			
	SPDC	22,865,305	22,865			
	EPNL	4,443,026	4,443			
	NAOC	4,040,188	4,040			
			42,715			
			gain/(loss)	0		
COMD	Liftings (per Lifter F2.02.12)			DPR Reconciliation		
	NNPC	9,469,792	9,470		11,367	
	NNPC (Dom Exp)	1,896,836	1,897			22,865
	SPDC		22,865			4,443
	EPNL		4,443			4,040
	NAOC		4,040			42,715
		42,715	42,715	0		

4.10 FPSO Trinity Spirit

Trinity Spirit is operated by Shebah Exploration and Production Co Ltd (SEPCOL) and handles product from Express/SEPCOL and Atlas. The status of SEPCOL as operator is subject to legal dispute by Express and limited information has been forthcoming.

UKPOKITI/Trinity Spirit

Operator: Shebah (SEPCOL)

Source	Production (P1.02)			
	Gross production	Field De-Watering	Implied Liquids	gain/(loss)
ATLAS	no data		#VALUE!	#VALUE!
SEPCOL	no data			
			gain/(loss)	1,803,030
	Terminal Balance			
SEPCOL	Gross Receipts	1,803,030		
SEPCOL	De-water	0		
SEPCOL	Implied Crude	1,803,030		
SEPCOL				
SEPCOL	Total Liftings	1,926,828		1,927
SEPCOL	Stock Change	-123,798		
	gain/(loss)	0		
			gain/(loss)	0
	Liftings (per Terminal Operator)			
		bbbls	bbbls (000s)	
SEPCOL	Express	1,733,459	1,733	
SEPCOL	Atlas	193,369	193	
			1,927	
			gain/(loss)	-1,326 (SEPCOL/Camac - no liftings data)
	Liftings (per Lifter F2.02.12)			
SEPCOL	SEPCOL	no data		
Camac	Camac	no data		
Express	Express	407,366	407	
Atlas	Atlas	193,369	193	
			601	
	Liftings per DPR data			
	SEPCOL		1,312	
	Camac		14	
	Express		407	
	Atlas		193	
			1,927	

Observations:

We have no data from SEPCOL or Camac regarding their liftings. However, if the data reported by DPR is correct then the terminal balance does balance.

4.11 FPSO Unity

FPSO Unity is operated by EPNL and handles product from the Odudu and Amenam-Kpono fields. Amenam-Kpono is subject to a unitisation agreement between EPNL(JV) and MPNU(JV).

ODUDU/Unity (Incl Amenam-Kpono)				Operator: EPNL	
Source EPNL	Production (P1.02)				
	Gross Production	Field De-Watering	Liquids passed on		
	83,709,577	-14,653,805	69,055,772		
	gain/(loss)				0
EPNL EPNL EPNL EPNL EPNL EPNL	Terminal Balance			DPR Fiscalised Crude	
	Gross Receipts		69,055,772		
	De-water/Term Adj		0		gain/(loss)
	Dry Crude		69,055,772	EPNL	69,056,104
	Total Liftings		-69,400,989		332
	Stock Change		-345,217		
	gain/(loss)				0
EPNL EPNL	Liftings (per Terminal Operator)		bbls	bbls (000s)	
	NNPC		30,479,110	30,479	
	EPNL		38,921,879	38,922	
				69,401	
	gain/(loss)				0
COMD COMD MPNU EPNL	Liftings (per Lifter F2.02.12)			DPR Reconciliation	
	NNPC		27,585,114	27,585	
	NNPC (Dom Export)		2,893,996	2,894	NNPC
	MPNU		3,909,259		30,479
	EPNL	(inc MPNU purchase)		38,922	EPNL
	Total		69,401		38,922
					69,401

Observations:

MPNU does not physically lift from Unity, rather it sells its entitlement from the unitisation agreement to EPNL at the terminal. This is not recognised by DPR on either their production or lifting reconciliations and could lead to confusion. DPR should identify the MPNU share on their reconciled production reports, since this also indicates a liability to pay Royalty and PPT. MPNU does indeed pay royalty and PPT on its production share.

4.12 FPSO Gray Warrior

ABO/Gray Warrior is operated by NAE under a PSC. SNEPCO is a partner in the operation.

ABO/Gray Warrior Balance

Operator: NAE

Source	Production (P1.02)		
	Gross production	Field De-Watering	Implied Liquids
NAE	11,321,806	-6,606	11,315,200
	gain/(loss)		6,606
	Terminal Balance		
NAE	Gross Receipts	11,321,806	
NAE	De-water/Term Adj	-6,606	
NAE	Implied Crude	11,315,200	
NAE	Total Liftings	-11,773,311	-11,773
NAE	Stock Change	-442,692	
	gain/(loss)	15,419	
	DPR Fiscalised Crude		
			gain/(loss)
NAE	11,315,648		448
	Liftings (per Terminal Operator)		
		bbls	bbls (000s)
NAE	NAE	4,889,236	4,889
NAE	NNPC	2,705,036	2,705
NAE	SNEPCO	4,179,039	4,179
			11,773
	gain/(loss)		1
	Liftings (per Lifter F2.02.12)		
NAE	NAE	4,890	
COMD	NNPC	2,705,036	2,705
SNEPCO	SNEPCO	4,179	4,179
		11,774	11,773
	DPR Reconciliation		
NAE		4,889	
COMD	NNPC	2,705	
SNEPCO	SNEPCO	4,179	
		11,773	

Observations:

NAE appear to have provided Net production data on the Production template. We understand that processing and de-watering are undertaken on the Abo field platform, however, this was not reflected in the production template.

4.13 FPSO Ailsa Craig

IMA/Ailsa Craig is a Sole Risk development operated by Amni International.

IMA/Ailsa Craig Operator: Amni International

Source	Production (P1.02)		
	Gross production	Field De-Watering	Liquids passed
AMNI	1,681,557	0	1,681,557
	gain/(loss)		0
	Terminal Balance		
AMNI	Gross Receipts	1,681,557	
AMNI	De-water	-849,562	
AMNI	Implied Crude	831,995	
AMNI	Total Liftings	-775,426	-775
AMNI	Stock Change	56,569	
AMNI	gain/(loss)	0	
	DPR Fiscalised Crude		
			gain/(loss)
AMNI	770,713		-61,282
	Liftings (per Terminal Operator)		
		bbls	bbls (000s)
AMNI	AMNI	775,426	775
			775
	gain/(loss)		0
	Liftings (per Lifter F2.02.12)		
AMNI	AMNI	775,426	775
			775
	DPR Reconciliation		
AMNI	775		0
	775		

4.14 FPSO Falcon

Yoho/Falcon is operated by MPNU. There are no 3rd party inputs.

YOH/O/Falcon			Operator: MPNU	
Source	Production (P1.02)			
	Gross production	Field De-Watering	Liquid passed on	gain/(loss)
MPNU	48,849,854	-1,525,292	48,962,803	1,638,241
	gain/(loss)		152,336	
	Terminal Balance			DPR Fiscalised Crude
MPNU	Gross Receipts	49,115,139		
MPNU	De-water	0		gain/(loss)
MPNU	Implied Crude	49,115,139	MPNU	49,115,159
MPNU	Total Liftings	-48,712,543		20
MPNU	Stock Change	344,046		
MPNU	gain/(loss)	-58,550		
	Liftings (per Terminal Operator)		bbl	bbl (000s)
MPNU	NNPC	16,048,736	16,049	
MPNU	MPNU	32,663,807	32,664	
			48,713	
	gain/(loss)		0	
	Liftings (per Lifter F2.02.12)			DPR Reconciliation
	NNPC	15,099,461	15,099	
COMD	NNPC (Dom Exp)	949,275	949	16,049
MPNU	MPNU		32,664	32,664
			48,713	48,713

Observations:

The gain of 1,638,241 bbls on the production balance may be due to metering tolerance of field measurements (2%). Similarly the small gain between the Production platforms and the FSO.

4.15 FPSO Sendje Berg

OKWORI/Sendje Berg is a PSC operated by Addax.

OKWORI/Sendje Berg Operator: ADDAX

Source	Production (P1.02)		
	Gross production	Field De-Watering	Implied Liquids
ADDAX	5,475,376		5,475,376
	gain/(loss)		0
	Terminal Balance		
ADDAX	Gross Receipts	5,475,376	
ADDAX	De-water	-150,124	
ADDAX	Implied Crude	5,325,252	
ADDAX	Total Liftings	-4,541,678	-4,542
ADDAX	Stock Change	798,963	
ADDAX	gain/(loss)	-15,389	
	DPR Fiscalised Crude		
			gain/(loss)
	ADDAX	5,340,638	15,386
	Liftings (per Terminal Operator)		
		bbl	bbl (000s)
ADDAX	ADDAX	3,594,831	3,595
ADDAX	NNPC	946,844	947
			4,542
	gain/(loss)		0
	Liftings (per Lifter F2.02.12)		
ADDAX	ADDAX	5,489	3,595
COMD	NNPC	946,844	947
			4,542
	DPR Reconciliation		
			4,542
			0
			4,542

Observations.

The development came into production during 2005 and all production was lifted as trial marketing. Under the terms of the PSC, during trial marketing, each party lifts and sells cargos (to determine a commercial market price), however, the proceeds of sale from each are remitted to the PSC account.

4.16 FPSO Bonga

Bonga is operated by SNEPCO under a PSC with ExxonMobil, NAE and EPNL as partners. Production commenced in November 2005 and there was a single lifting in December for market testing purposes.

BONGA		Operator: SNEPCO	
Source	Production (P1.02)		
SNEPCO	Gross production	Field De-Watering	Implied Liquids
	1,471,835		1,471,835
			gain/(loss)
			0
	gain/(loss)		373
SNEPCO	Terminal Balance		DPR Fiscalised Crude
SNEPCO	Gross Receipts	1,472,208	
SNEPCO	De-water	-374	
SNEPCO	Implied Crude	1,471,834	
SNEPCO	Total Liftings	-196,821	SNEPCO
SNEPCO	Stock Change	1,275,014	0
SNEPCO	gain/(loss)	-393,641	-1,471,835
SNEPCO	Liftings (per Terminal Operator)		bbls bbls (000s)
	SNEPCO	196,821	197
			197
	gain/(loss)		0
SNEPCO	Liftings (per Lifter F2.02.12)		DPR Reconciliation
	SNEPCO	196,821	197
	NNPC		NNPC
			0
		197	197

Observations:

DPR did not conduct a reconciliation review with SNEPCO in 2005.

5 Summary Of Production Entitlement

The following table summarises the total allocation of crude to equity owners across all their interests and compares it with total liftings.

The data is aggregated from the terminal balances (after terminal adjustments), set out in the following sections.

Allocation of dry crude production to owners (bbls)

Company	Production Allocation	Actual Lifting	Stock change
ADDAX	13,690,709	12,938,259	752,450
AENR	8,509,709	8,507,709	2,000
AMNI	831,995	775,426	56,569
ATLAS	163,546	193,369	(29,823)
CAMAC	40,987	14,431	26,556
CAV	1,408,276	1,478,265	(69,989)
CNL	54,296,987	54,190,306	106,681
CONOIL	725,088	760,000	(34,912)
CONT	13,242,750	14,291,101	(1,048,351)
DUBRI	152,705	160,000	(7,295)
EPNL	73,750,586	73,501,169	(650,203)
EXPRESS	942,703	407,366	535,337
MONI	5,794,198	5,982,132	(187,934)
MPNU	106,409,173	101,301,208	(63,837)
NAE	4,321,441	4,889,236	(506,663)
NAOC	30,629,140	32,663,551	(1,526,252)
NDPR	141,014	50,000	91,014
NNPC	454,978,919	456,422,853	1,866,691
NPDC	15,070,460	15,376,613	(306,153)
PAN	3,452,686	3,211,052	241,634
PHILLIPS	12,367,430	12,647,481	(280,051)
SEPCOL	655,794	1,311,662	(655,868)
SNEPCO	5,760,557	4,375,860	1,384,697
SPDC	109,570,258	110,689,402	1,921,319
Total	916,907,111	916,138,451	1,617,617

Notes:

- 1)PSC Royalty and PPT oil is allocated to NNPC
- 2)Allocation adjusted for Carry Agreements
- 3)EPNL allocation/lifting excludes MPNU share of Amenam
- 4)Bonga production 100% allocated to Snepco
- 5)Assumed Service contactors lifted 100% of entitlement
- 6)Cavendish data based on DPR return

Sources: Company Production returns

Terminal Balances

Company Liftings

Field Contract Data

PSC and Carry data returns

6 Production Allocation Overview

6.1 *Reconciliation of Production Allocation*

Correct allocation of Production to companies is important since it determines the Royalty liability. Royalty is due on production. Other taxes such as PPT are paid once the product has been monetised. For each field development, the contractual arrangements between the interested parties will determine which parties are responsible for paying royalties. These arrangements are discussed in detail below.

Critical to this discussion is a common understanding of the point in the production process at which the liability to Royalty occurs. As noted in the 1999-2004 Audit there is no common agreement on this between DPR and the producing companies. Theoretically, royalty is payable on production on a field-by-field basis and the quantum is dependent, not only on the realisable price, but also on the relevant field API. However, common practice by the lifting companies is to calculate royalty on liftings and shipment APIs, which are a blend of individual field APIs.

At the time the agreements and operating practices were established, this was probably a pragmatic simplification. With each JV operating their own Terminal the liftings and APIs could be expected to average out over time. However, the infrastructure is now considerably more complex. All the onshore terminals receive product from 3rd parties and must maintain records of receipts, stock, liftings and terminal adjustments for more than one producer– and with the advent of marginal fields can only become more so. Furthermore, the terminal operator is unlikely to know the split of entitlement between the partners of this 3rd party production (especially if these are PSCs or there are Carry Agreements in place).

Recommendation: For the 2006 Audit. To resolve this difficulty, a template is required for each 3rd party producer to identify their partner's entitlement to production (including production under unitisation agreements) and stock at each terminal they deliver to, but do not operate. So for example, SPDC JV should provide data on the entitlement of each partner to product held at Brass Terminal. The total for the JV should reconcile to the terminal operator's (NAOC) data. Consideration should be made to whether this entitlement is calculated before or after terminal adjustments.

6.2 *Types of contractual arrangement*

How the production from a field is allocated between the various interested parties depends on the contractual arrangements in place. There are five main arrangements:

- Sole Risk
- Service Contract
- Joint Venture (JV)
- Unitisation Agreement
- Production Sharing Contract (PSC)

Under PSCs, Service Contracts and Carry Agreements, oil is allocated to partners in lieu of cash. The amount of oil is determined by various formulae that relate to the notional value of the oil. Various prices are referenced in agreements (e.g. Realisable Price, Official Selling Price etc). Depending which price is used the associated quantum of Oil changes. The allocations identified below are based on Company data returns, which may or may not be agreed by all parties.

6.2.1 Sole Risk

In this arrangement, since NNPC has no interest in the development, the licence holder is entitled to 100% of production and is liable for payment of all relevant Taxes, Royalties and Rentals. The holder of a Sole Risk licence may invite other parties to participate, either by selling equity or by way of a technical/service agreement. Depending on the terms of the agreement those partners may be entitled to lift oil (and may be liable to pay taxes and/or royalties).

6.2.2 Service Contract

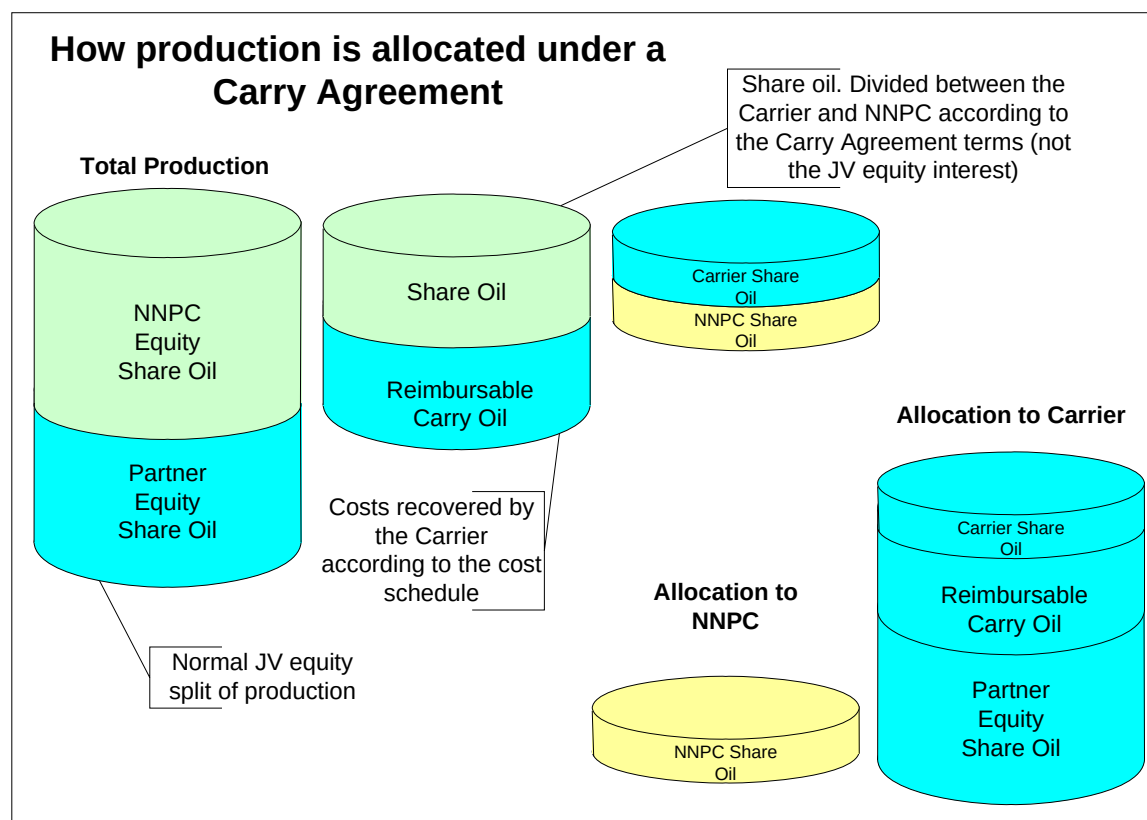
Under a service contract the ownership of the oil remains with NNPC. So NNPC is liable to pay all taxes and royalties on production. The contractor is entitled to be paid for the service and NNPC may pay the contractor with Oil rather than cash. The entitlement will depend on the contract terms and the costs incurred running the operation.

6.2.3 Joint Venture

Under the joint venture agreement, each of the partners is liable to pay its own share of costs and in return is entitled to a proportionate share of equity oil. Each partner is liable to pay taxes and royalties on its own share of the oil. So for example in the Mobil JV, NNPC has a 60% share of the Joint Venture and is entitled to 60% of the Oil.

The situation is complicated for a small number of developments where a **Carry Agreement** is in place. These are special arrangements to enable a development to go ahead without all the JV partners having to pay their share of costs. The non-paying partner is "carried" by the others. Carry Agreements are complex, but in principle the allocation of oil is as follows.

The Carrying Party is entitled to its normal share of equity oil. The NNPC equity oil is the divided up. First, the Carrying Party is entitled to oil to cover the reimbursable carry costs. The remaining oil is then shared, but (usually) in a different proportion to the normal JV equity shares (e.g. on the Yoho Carry the share oil is divided NNPC (57%), MPNU (43%) instead of 60:40). Whoever is allocated the oil is liable to pay royalties and tax on it.



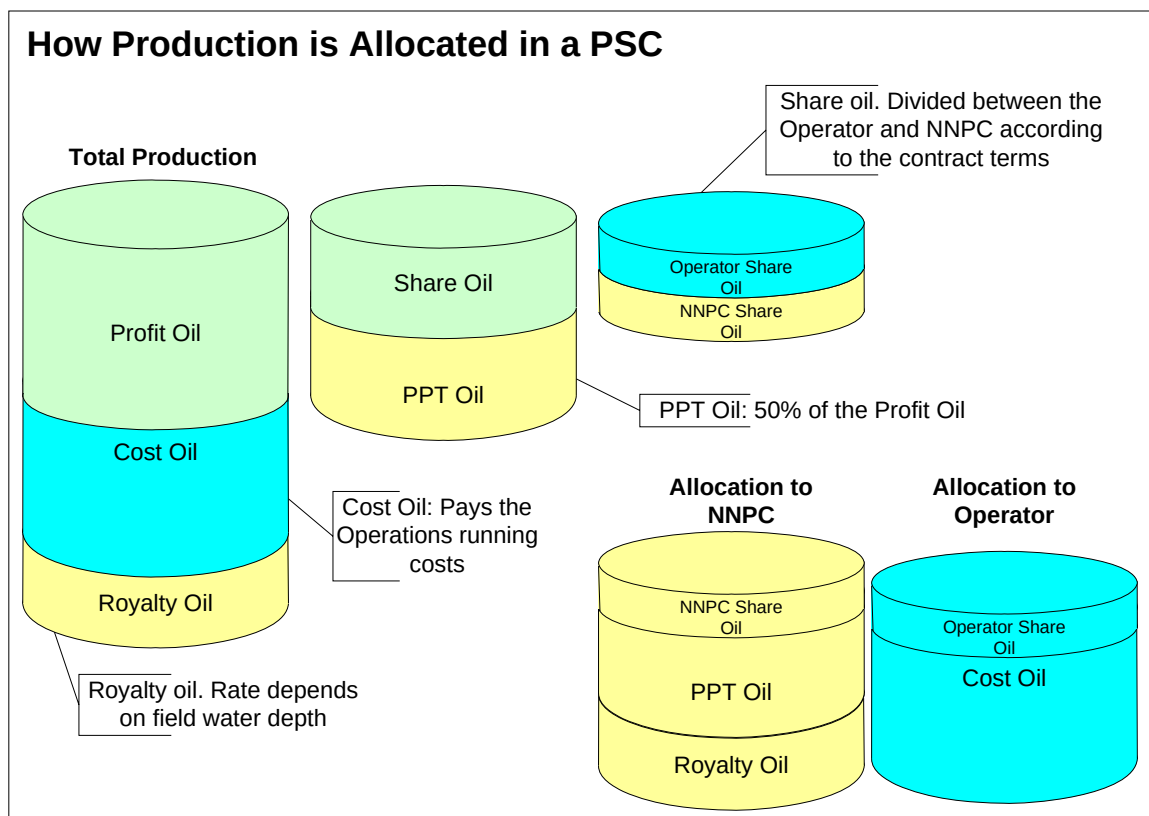
6.2.4 Unitisation Agreement

Where the extent of a field covers more than one Licence area, the holders of each licence are entitled to a share of production. The unitisation agreement defines relative proportions due to each, normally worked out from the areas of the field sitting in each licence area. For example the Belema field is unitised between the Shell JV (9%) and the Chevron JV (91%). So the oil instead of being allocated NNPC: 60% and CNL: 40% it is split as follows:

Belema	CNL JV	SPDC JV	Total	
	91%	9%		
NNPC	589,168	53,414	642,581	59.55%
SPDC		29,135	29,135	2.70%
EPNL		9,712	9,712	0.90%
NAOC		4,856	4,856	0.45%
CNL	392,778		392,778	36.40%
Total	981,946	97,116	1,079,062	

6.2.5 Production Sharing Contract

Under a PSC, NNPC is the licence owner and has a contract with the Contractor to develop the field and share the oil. As the licence holder, NNPC is liable to pay all relevant Taxes, Royalties and Rentals, whereas the Contractor pays all the costs of developing the and running the field. Oil is allocated between the Contractor and NNPC to meet these liabilities way:



7 Reconciliation of Production Allocation by Terminal

In this section, we set out the net production at each terminal and show the allocation of production from each operation between the parties participating in each operation.

Production is “net” of terminal adjustments. The adjustments are applied by the terminal operator and can be of the order of 0.1% of production. They are in essence a cost allocation for the use of the pipeline and terminal including losses through evaporation and spills that may occur.

7.1 Bonny

Production Entitlement after terminal adjustments					
	SPDC JV	EPNL JV	CNL JV	NDPR	Total
NNPC	85,197,203	6,334,473	9,052,205		100,583,881
SPDC	46,471,202				46,471,202
EPNL	15,490,401	4,222,982			19,713,383
NAOC	7,745,200				7,745,200
CNL			6,034,803		6,034,803
NDPR				141,014	141,014
Total	154,904,006	10,557,455	15,087,008	141,014	180,689,483

SPDC JV includes all production from SPDC licensed fields plus 9% of the Belema Unitisation. Elf and Chevron JVs are 3rd party injections into Bonny and NDPR (Niger Delta Petroleum Resources) is a sole risk addition. The 3rd Party additions are subject to terminal adjustments and will be a fraction of a percent below their quoted production figures.

7.2 Forcados

Production Entitlement after terminal adjustments					
	SPDC JV	PAN JV	NAOC JV	NPDC	Total
NNPC	74,382,361	5,179,028	1,300,612		80,862,001
SPDC	40,572,197				40,572,197
EPNL	13,524,066				13,524,066
NAOC	6,762,033		433,537		7,195,570
NPDC				2,114,972	2,114,972
PanOcean		3,452,686			3,452,686

PHILLIPS			433,537		433,537
Total	135,240,656	8,631,714	2,167,686	2,114,972	148,155,028

SPDC JV includes all production from SPDC licensed fields. Pan Ocean and Agip JVs are 3rd party injections into Forcados and NPDC is a sole risk addition. The 3rd Party additions are subject to terminal adjustments and will be a fraction of a percent below their quoted production figures. Note that Agip is a participant in both the SPDC JV and NAOC JV.

7.3 Escravos

Production Entitlement after terminal adjustments					
	CNL exc carry	Delta South	Meji	Meren	CNL total
NNPC	34,156,950	5,910,449	10,505,093	14,924,762	65,497,254
CNL	22,771,300	4,398,553	8,166,550	10,106,727	45,443,130
CONOIL					
DUBRI					
Total	56,928,250	10,309,002	18,671,643	25,031,489	110,940,384

Production Entitlement after terminal adjustments				
	CNL JV total	DUBRI	CONOIL	Total
NNPC	65,497,254			65,497,254
CNL	45,443,130			45,443,130
CONOIL			725,088	725,088
DUBRI		152,705		152,705
Total	110,940,384	152,705	725,088	111,818,177

There are three carry agreements in place on fields delivering to Escravos. These modify the entitlement from the original NNPC 60% CNL 40%. In addition, Dubri and Conoil Producing are Sole Risk operations using Escravos Terminal.

7.4 Qua Ibo Terminal (QIT)

Production Entitlement after terminal adjustments			
	MOBIL JV excl PIP	PIP carry	Total

NNPC	67,976,093	9,504,816	77,480,909
MPNU	45,317,396	14,956,214	60,273,610
Total	113,293,489	24,461,030	137,754,519

The QIT terminal PIP Carry agreement modifies the allocation of oil to the JV partners.

7.5 OSO Condensate

Production Entitlement after terminal adjustments			
	MOBIL JV		Total
NNPC	13,849,641		13,849,641
MPNU	9,233,094		9,233,094
Total	23,082,735		23,082,735

Production is allocated 60% NNPC, 40% MPNU in line with the JV equity.

7.6 Yoho/Falcon

Production Entitlement after terminal adjustments			
	carry		Total
NNPC	16,083,007		16,083,007
MPNU	32,973,566		32,973,566
Total	49,056,573		49,056,573

Yoho/Falcon is financed through a carry agreement that modifies the allocation of oil to the JV partners as follows:

	MPNU Equity Oil	Carry Recovery Oil	Carriers Share Oil	Total MPNU Oil	NNPC Share Oil	Total
	19,622,629	1,218,143	12,132,794	32,973,566	16,083,007	49,056,573

7.7 Oloibiri/Pennington

Production Entitlement after terminal adjustments			
	CNL JV	CONT	Total
NNPC	3,282,446		3,282,446
CNL	2,188,297		2,188,297
CONT		13,242,750	13,242,750
Total	5,470,743	13,242,750	18,713,493

CNL JV Oil is allocated to the partners 60% NNPC, 40% CNL in line with the JV equity. Continental Oil & Gas is a Sole Risk Operation using the Terminal facilities.

7.8 Okwori/Sendje Berg

Production Entitlement after terminal adjustments			
	ADDAX PSC		Total
NNPC	946,844		946,844
ADDAX	4,378,408		4,378,408
Total	5,325,252		5,325,252

Okwori/Sendje Berg is operated by Addax under a PSC. 2005 was the start up year for this operation, so all the cargos handled were during the trial marketing period. NNPC marketed one cargo, and this is reflected in the above table, however, since the trial marketing period is used to determine commercial prices it is not possible yet to attribute cost and profit oil.

7.9 Antan/Knock Taggart

Production Entitlement after terminal adjustments			
	ADDAX PSC	MONI	Total
NNPC	9,017,470		8,719,233
ADDAX	8,181,896		8,480,133
MONI		5,794,198	5,794,198
Total	17,199,366	5,794,198	22,993,564

Antan/Knock Taggart is the operated by Addax under a PSC. Moni Pulo is a Sole Risk Operator using the terminal. The Production Entitlement from the PSC is built up as follows (note: Addax has not completed all financial templates and the Cost Oil figure is subject to

verification. Also the PSC covers the small onshore operation at Izombe, which feeds into Brass Terminal. This is considered separately in the Brass reconciliation)

	Production	Royalty Oil	Cost Oil	Profit Oil	PPT Oil	Share Oil	Total
Field	17,199,366	1,336,963	3,061,559	12,800,844	6,400,422	6,400,422	
NNPC		1,336,963			6,400,422	1,280,084	9,017,470
ADDAX			3,061,559			5,120,338	8,181,896

7.10 Ododu/Unity

Production Entitlement			
	OML 95/97	Amenam	Total
NNPC	16,877,816	15,244,868	32,122,684
EPNL	11,251,878	21,752,307	33,004,184
MPNU		3,928,903	3,928,903
Total	28,129,694	40,926,078	69,055,772

Ododu/Unity is an EPNL JV operated facility. The Production from OMLs 95 and 97 are allocated NNPC 60%, EPNL 40% according to the EPNL JV equity shares. Amenam is complex. Not only is it a unitised field (NNPC 60%, EPNL 30.4%, MPNU 9.6%), but there are also two carry agreements in place.

We have not yet been able to verify the EPNL data supplied on the two carry agreements, so the entitlement above should be regarded as provisional.

7.11 Abo/Gray Warrior

Production Entitlement after terminal adjustments			
	NAE PSC		Total
NNPC	2,705,036		2,705,036
NAE	4,321,441		4,321,441
SNEPCO	4,288,723		4,288,723
Total	11,315,200		11,315,200

Abo/Gray Warrior is a PSC operated by NAE. Two companies, NAE and SNEPCO have a working interest in the PSC with shares of 50.19% and 49.81% respectively.

	Production	Royalty Oil	Cost Oil	Profit Oil	PPT Oil	Share Oil	Total
	11,315,200	905,216	7,410,284	2,999,700	1,499,850	1,499,850	
NNPC		905,216			1,499,850	299,970	2,705,036
Operator			7,410,284			1,199,880	8,610,164
NAE	50.19%						4,321,441
SNEPCO	49.81%						4,288,723

7.12 EA/Sea Eagle

Production Entitlement after terminal adjustments			
	Carry		Total
NNPC	10,130,305		10,130,305
SPDC	21,014,237		21,014,237
EPNL	7,004,746		7,004,746
NAOC	3,502,373		3,502,373
Total	42,439,486		42,439,486

EA/Sea Eagle is financed through a carry agreement. The production entitlements differ from the SPDC JV equity shares as follows:

	Carriers' Equity Oil	Carry Recovery Oil	Carriers Share Oil	Total Carrier Oil	NNPC Share Oil	Total Production
Carry Parties	19,097,769	1,505,456	10,918,131	31,521,355	10,918,131	42,439,486
			SPDC	21,014,237		
			EPNL	7,004,746		
			NAOC	3,502,373		

This assumes that all the remaining partners are carrying NNPC in proportion to their original shares in the JV.

7.13 Okono/Mystras

Production Entitlement	after terminal adjustments
------------------------	----------------------------

	Service Contract		Total
NPDC	12,955,488		12,955,488
AENR	6,947,709		6,947,709
Total	19,903,197		19,903,197

Okono/Mystras is operated by AENR under a service contract to NPDC. NPDC pays Royalty and Taxes on the total production. The AENR entitlement is determined by the Service Contract Terms, which are not available to us. The assumption made here is that AENR lifted its entitlement and the balance accrues to NPDC.

7.14 Brass

Production Entitlement after terminal adjustments						
	NAOC JV	ADDAX PSC	AENR (SC)	CNL JV	SPDC unit'n	Total
NNPC	35,801,680	439,641	2,755,081	946,135	2,773,141	42,715,678
AENR			1,562,000			1,562,000
NAOC	11,933,893				252,104	12,185,997
ADDAX		832,168				832,168
PHILLIPS	11,933,893					11,933,893
EPNL					504,207	504,207
SPDC					1,512,622	1,512,622
CNL				630,757		630,757
Total	59,669,466	1,271,809	4,317,081	1,576,892	5,042,074	71,877,322

Brass is the most complex terminal. There are inputs from the NAOC JV, Addax PSC, an AENR Service Contract, the CNL JV and a number of SPDC JV unitisations.

The NAOC JV and CNL JV allocations are made in line with the respective equity shares of the JV partners.

The AENR/NNPC service Contract is allocated on the assumption that AENR lifted its entitlement under the contract. NNPC is responsible for paying all Royalty and Taxes on total production.

The Addax PSC allocation is according to the PSC terms as follows (we do not have details of the cost oil, so this allocation assumes NNPC lifted its entitlement at Brass).

	Production	Royalty Oil	Cost Oil	Profit Oil	PPT Oil	Share Oil	Total
Field	1,271,809	63,590	581,467	626,752	313,376	313,376	
NNPC		63,590			313,376	62,675	439,641
ADDAX			581,467			250,701	832,168

The SPDC JV Unitisation allocation is based on the Production allocated to SPDC JV on the Brass Terminal Balance (we do not have separate production data for the unitised fields). This production is allocated to the SPDC JV partners according to equity share.

7.15 Other Terminals

Apart from Bonga, the remaining terminals (Ima/Ailsa Craig, Ukpokiti/Trinity Spirit and Obe/Crystal Sea) are all Sole Risk operations and entitlement is 100% to the equity participants.

Bonga was in trial marketing and a single cargo had been lifted. Consequently there was no detail on costs or PPT liability so all production has notionally been allocated to SNEPCO.

8 GAS SYSTEM

8.1 Physical Audit Procedure - Methodology for physical gas flows

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

The methodology used to carry out this task has been to compare the information provided by producers with the data provided by NGC and NLNG.

- Template P2.01 asked producers to provide the following information about gas
 - o Gas produced
 - o Gas sold to other parties
 - o Gas used in production such as lift gas, re-injection, own usage etc.
 - o Gas flared

8.2 Volumetric Analysis and Summaries

Data was provided from all the gas producing companies and the major gas receiving companies (NLNG and NGC) for analysis of the flows.

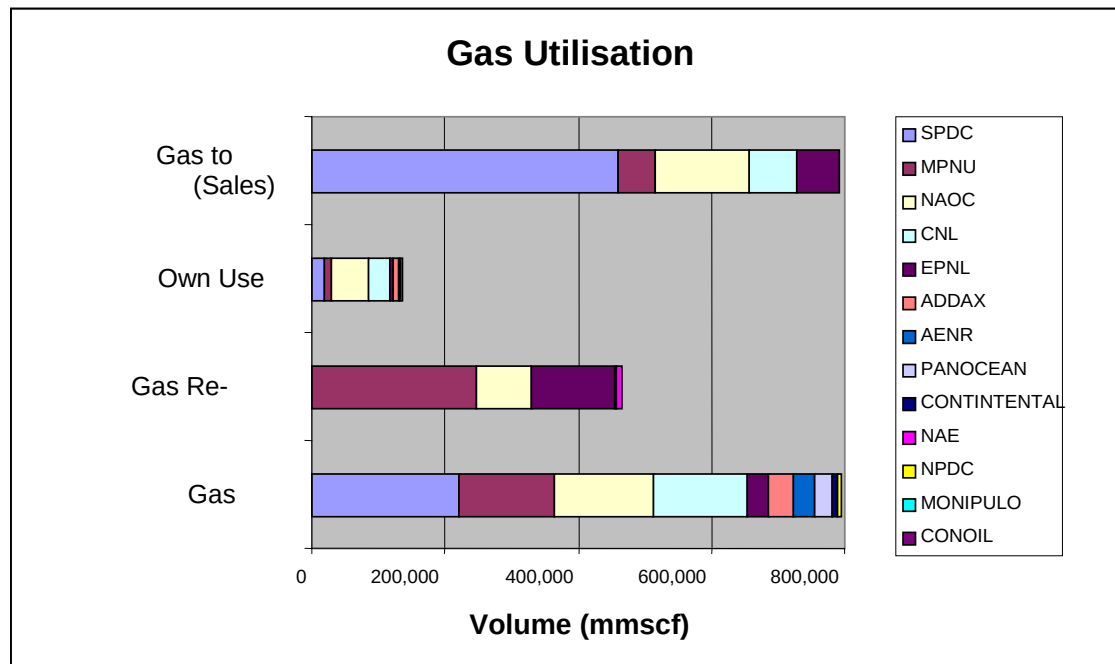
Table 1 – Total Gas Produced 2005 (MMSCF)

Producer	Gas Flared	Gas Re-injection	Own Use Gas	Gas to Others (Sales)	Total Gas Produced
SPDC	220,838.991	770.104	17,311.859	459,354.933	698,275.886
MPNU	142,632.494	246,061.591	11,239.448	57,006.452	456,157.219
NAOC	148,222.453	83,719.009	57,085.403	139,976.824	429,003.689
CNL	142,331.137		30,830.549	71,118.655	244,280.341
EPNL	32,201.542	123,557.562	7,099.760	63,681.022	226,539.886
ADDAX	35,946.000	3,038.000	7,492.000		46,480.000
AENR	32,035.777		686.969		32,722.746
PANOCEAN	25,868.237		1,299.262		27,167.499
CONTINENTAL	9,981.486		103.546		10,085.032
NAE	151.960	8,242.520	1,300.710		9,695.190
NPDC	3,795.623		199.770		3,995.393
MONIPULO	1,584.266		273.176		1,857.442
CONOIL	391.800		16.360		408.200
Total	795,981.765	465,388.785	134,938.811	791,137.886	2,186,668.523

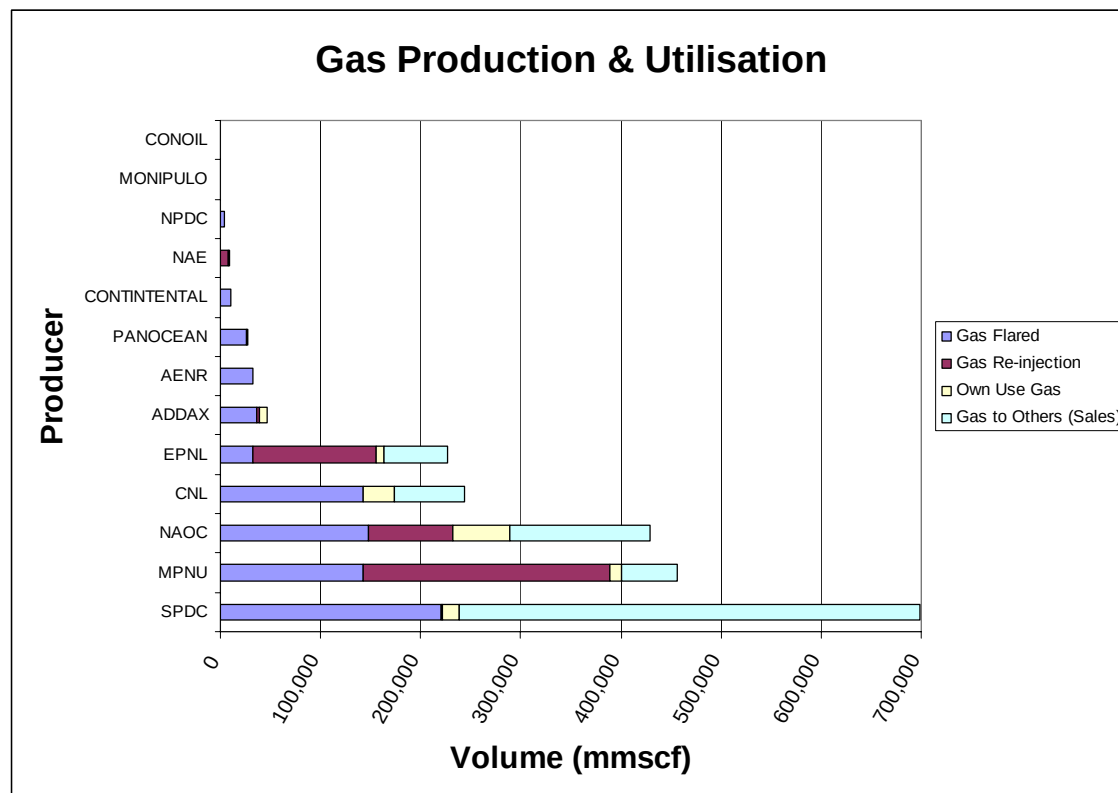
The above table summarises the breakdown between:

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

Typically "Own Use" gas is used as fuel to operate processing equipment.



The following chart shows the relative volumes of gas produced by each company:



8.3 Reconciliation of Gas Sales.

Seller	NLNG	NGC	IPP	Other	Total
EPNL	62,705.140			975.882	63,681.022
CNL		62,329.440		8,789.215	71,118.655
SPDC	307,671.761	131,519.843	17,061.387	3,101.941	459,354.933
MPNU				57,006.452	57,006.452
NAOC	141,628.667		12,656.519	10,340.855	164,626.041
Total	512,005.568	193,849.283	29,717.906	80,214.345	815,787.103

[NOTE: What is shown here as MPNU Gas Sales is in fact gas supply to the NGLs business. This is a separate legal entity that processes gas and as such is not a covered entity for the purposes of the audit. It is included here to show a true picture of the volumes of gas productively used]

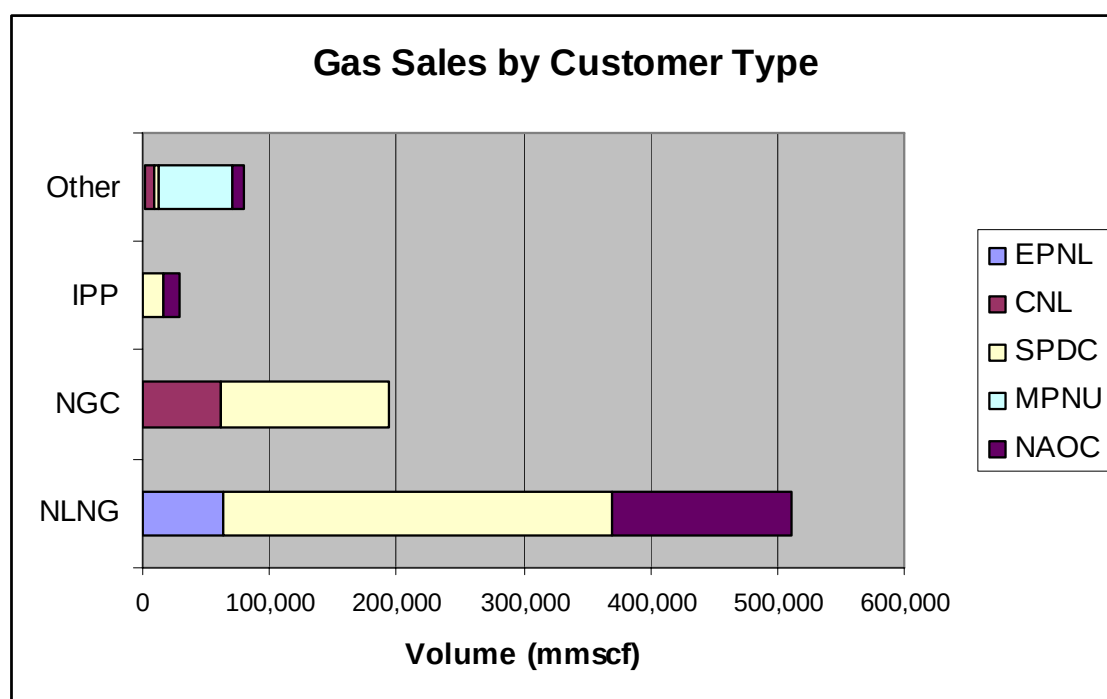
Reconciliation of gas sales is not possible because there are not two independent points of measurement. Gas entering the NGC system is measured at the custody transfer point. Gas delivery to NLNG is measured at the exit from the supply gas plants, but not on arrival at the NLNG terminal.

According to NLNG "All the gas received by NLNG is upstream processed (dry) and therefore considered and reported as 'dry gas' (even though later during the LNG processing some NGLs are produced)... The data recorded are 'as invoiced' by the gas suppliers not further normalised."

8.4 SPDC Custody transfer points...

The SPDC gas infrastructure is complex, with a number of gas streams coming together and diverging to different end points. For reference, here are the SPDC custody transfer points:

NLNG:	Bonny NAG Gas Plant, SOKU Gas Plant, Cawthorne Channel, AWOB & Bonga
NGC	NEPA Afam, NGC-ALSCON, NGC-NAFCON, Rivers State Power Plant Eleme, SAPL Gas Plant, OBEN Gas Plant, UTOR Gas Plant, ODIDI Flow Station & UGHELLE Gas Plant
Power	- SPDC IA-PHC, KOCR Flow Station & UGHELLE Gas Plant Manifold
Others	UGHELLE Gas Plant Manifold, Int Equit Ltd Aba, Int Glass Ind Aba, Lever Brothers Aba, Rivers State Electric Board, Nigerian Breweries Aba, PZ Ind Aba, SNG-Glass Force Ltd Lagos, Textile Mills Aba,



8.5 Ownership of Gas

Currently SPDC attributes gas ownership in proportion to JV equity participation. With supplies coming on stream from Bonga (and other offshore PSCs) this may become more complex (depending on the Gas Development Agreements agreed between NNPC and the PSC Contractors).

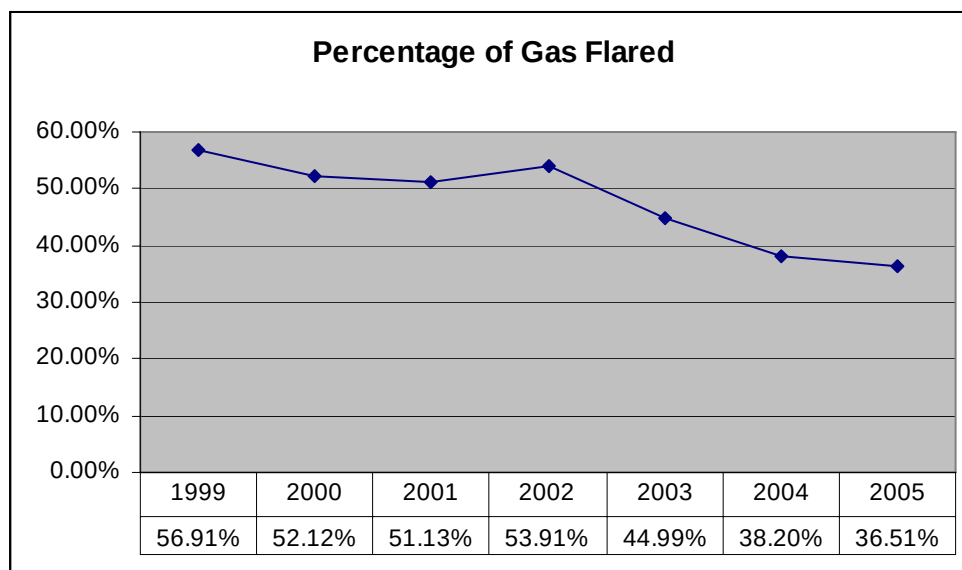
For example, EPNL supplies gas to NLNG from Amenam. MPNU has a unitisation agreement on that field. We do not know the details of the gas development/sales

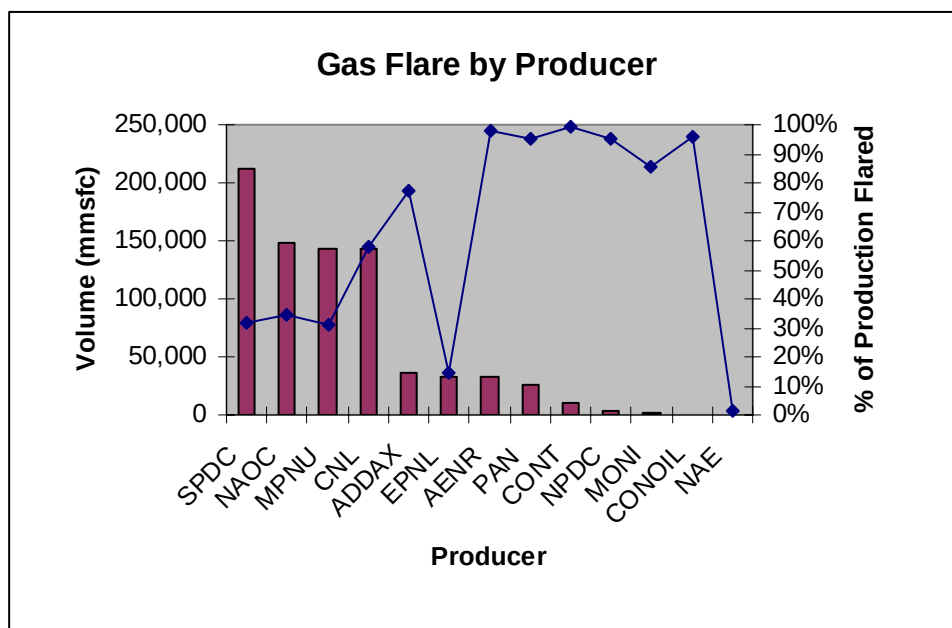
agreements so cannot judge whether MPNU incurs a CIT liability as a result – FIRS should investigate.

Furthermore, as more IPP schemes come on stream and as companies seek to utilise more gas to comply with the FGN zero-flare target, it becomes ever more urgent to place these gas developments on a solid regulatory and operational footing. For example, it is not transparent how operations transfer gas between them for operational purposes and whether or not such transfers should constitute a “gas sale” and incur a CIT liability

8.6 Summary of gas flaring for the period 1999 – 2004

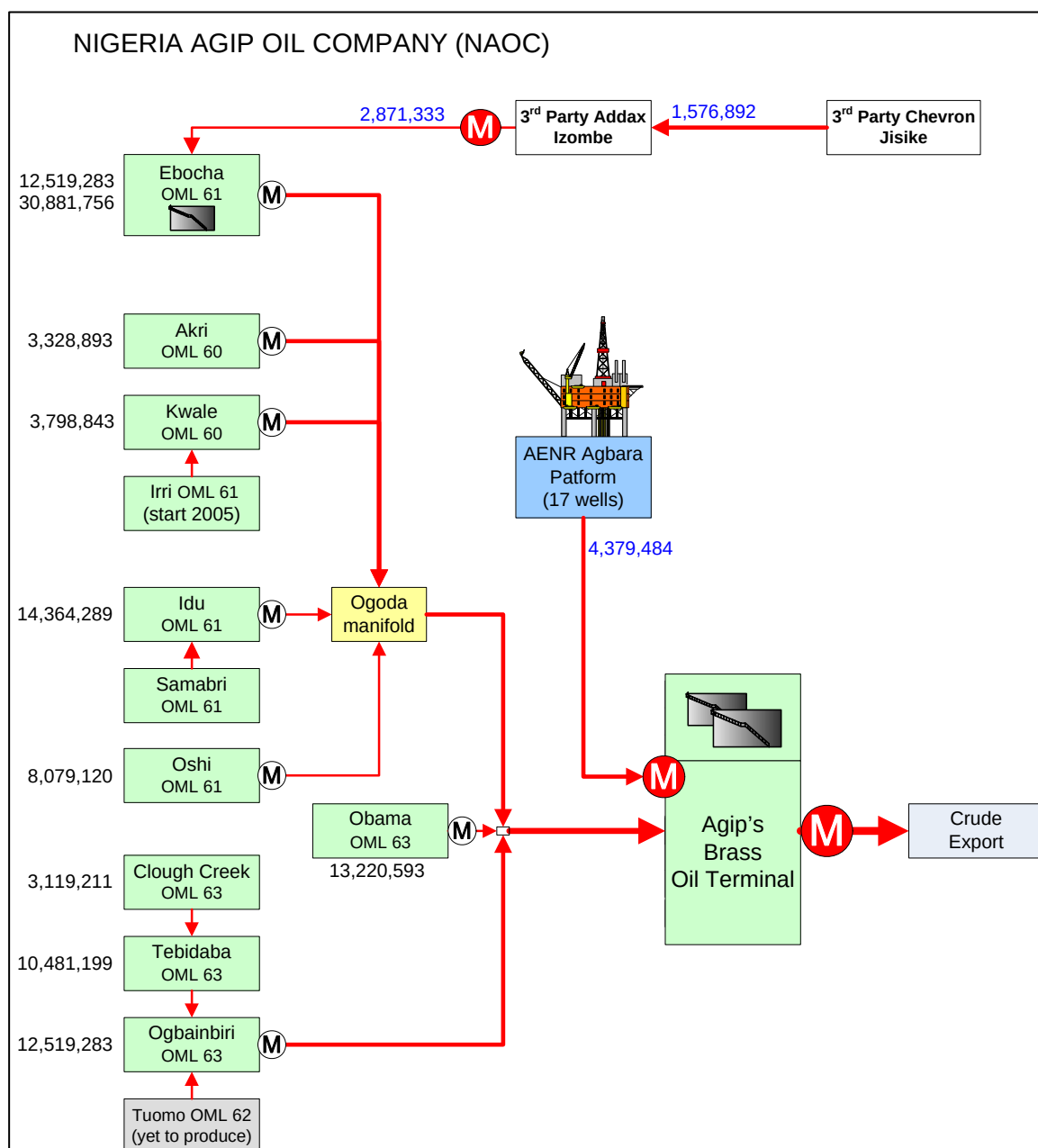
Gas flaring or rather the reduction of gas flaring in Nigeria is a major political, environmental and commercial issue. Initially gas flaring was planned to be reduced to zero by 2004, the data has now been extended to 2008. The following chart shows the reduction in the percentage of gas flaring from 1999 to 2005. Whilst it can be seen that a reduction of some 21% from 57% to 36% has taken place over a period of seven years the ability of Nigeria to further reduce to zero by 2008 must be in doubt. Steps being taken to reduce flaring include a number of IPP (Power Generation) schemes and GTL projects that are beginning to come on stream.

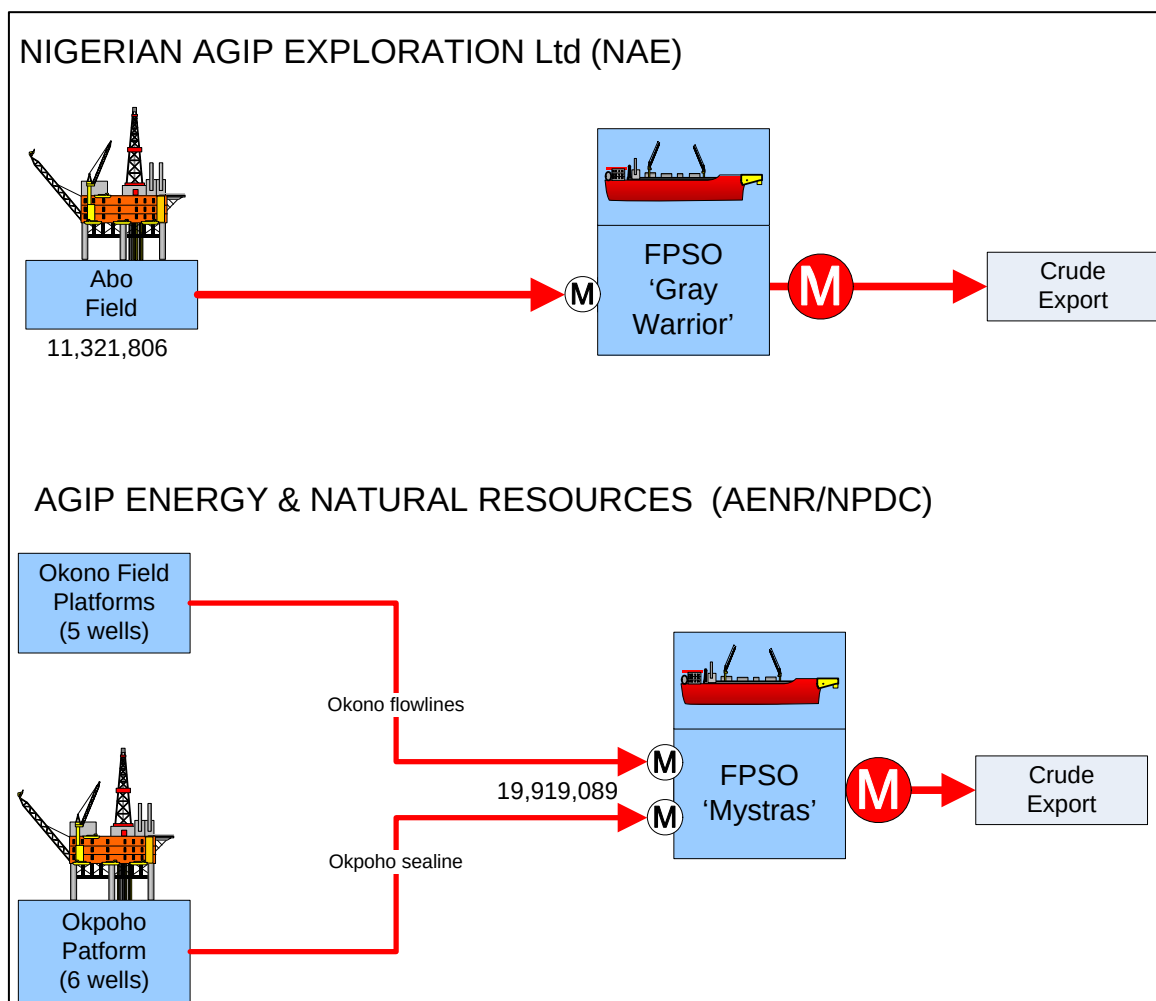


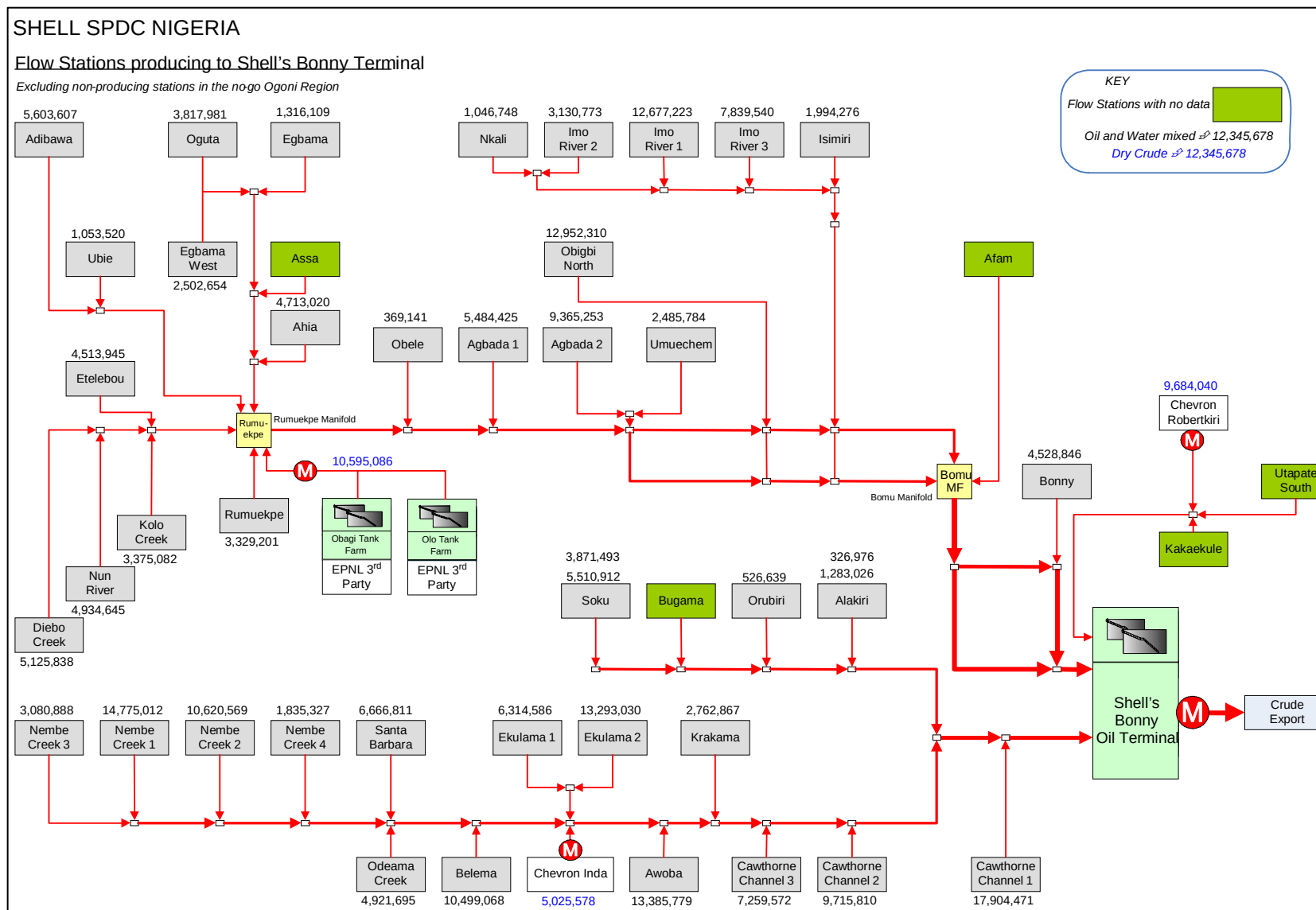


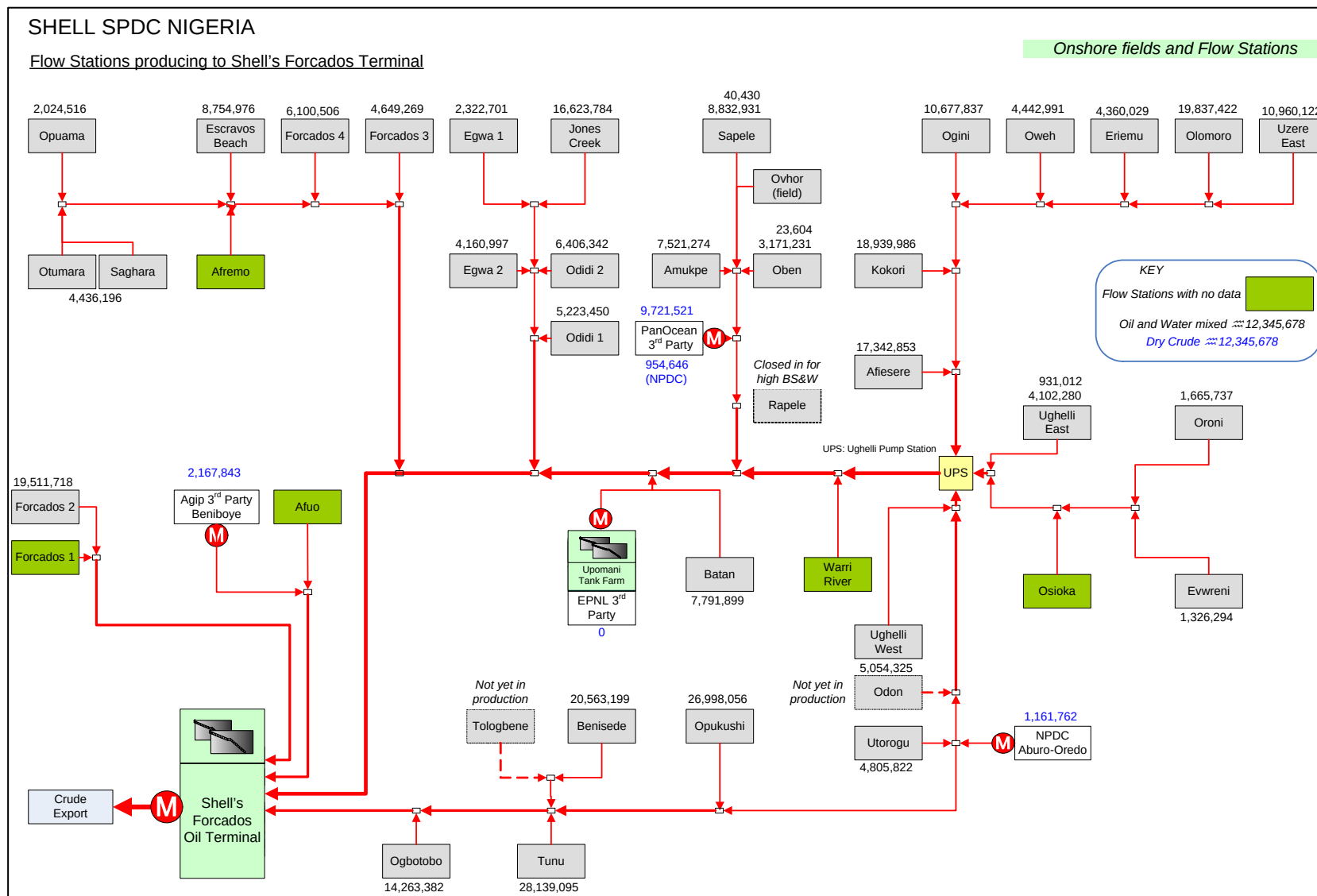
Attachment: Flow schematics

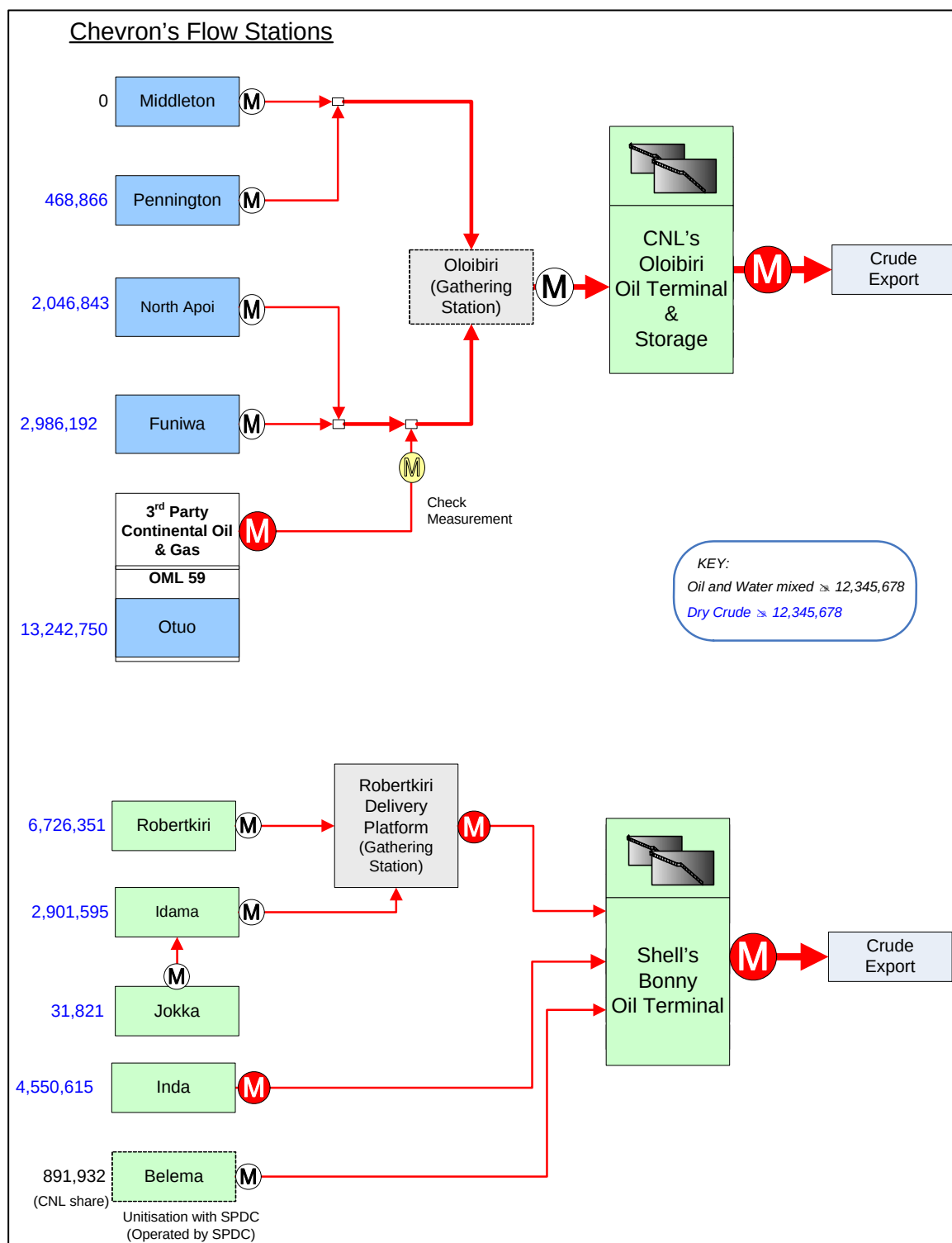
The following schematics indicate the volumetric flows from each flow station (either Oil & Water or Dry Crude depending on whether de-watering is undertaken at or prior to the flow station). These are provided to aid understanding of the oil flows and are not comprehensive. All values are barrels (bbls).

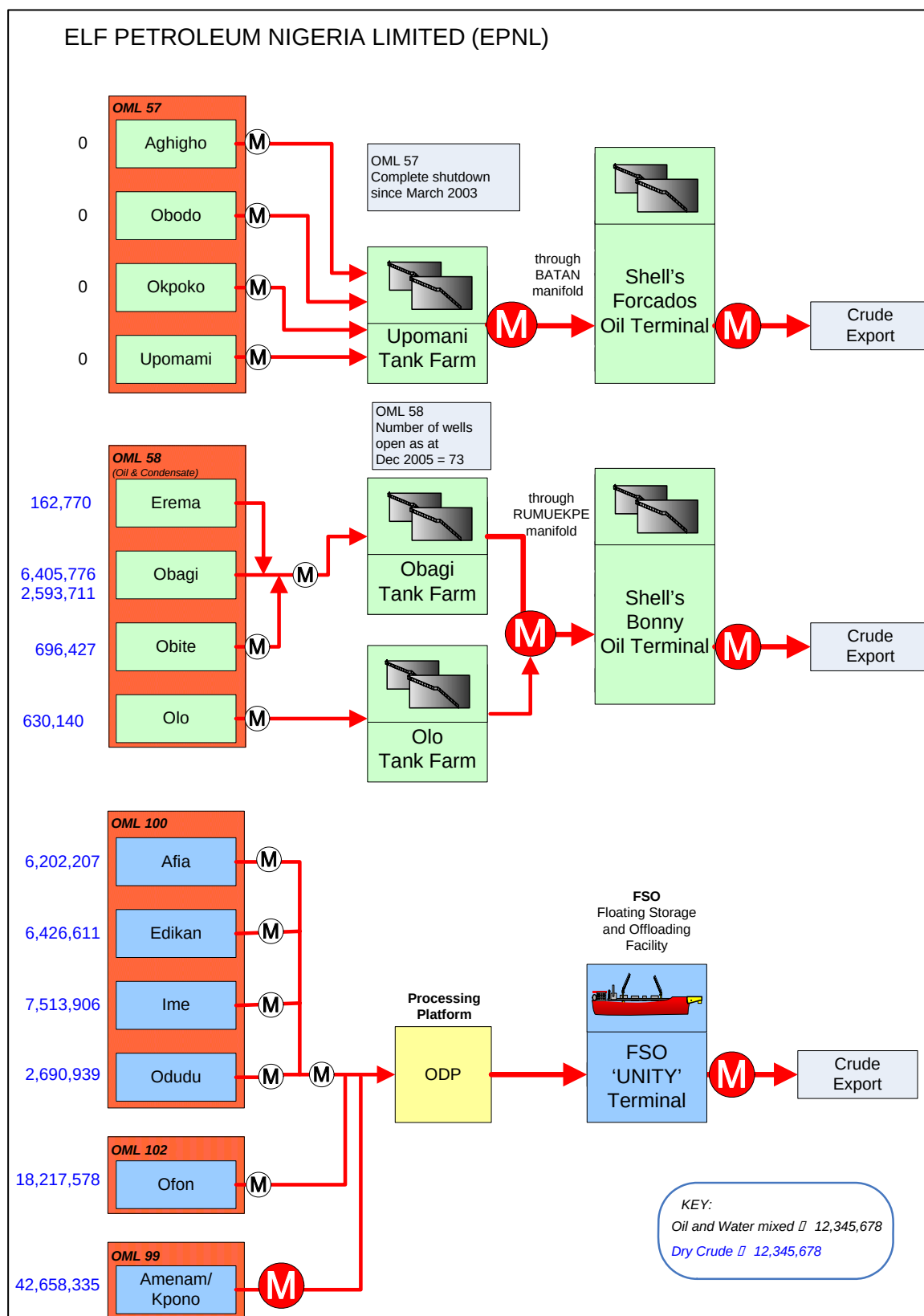


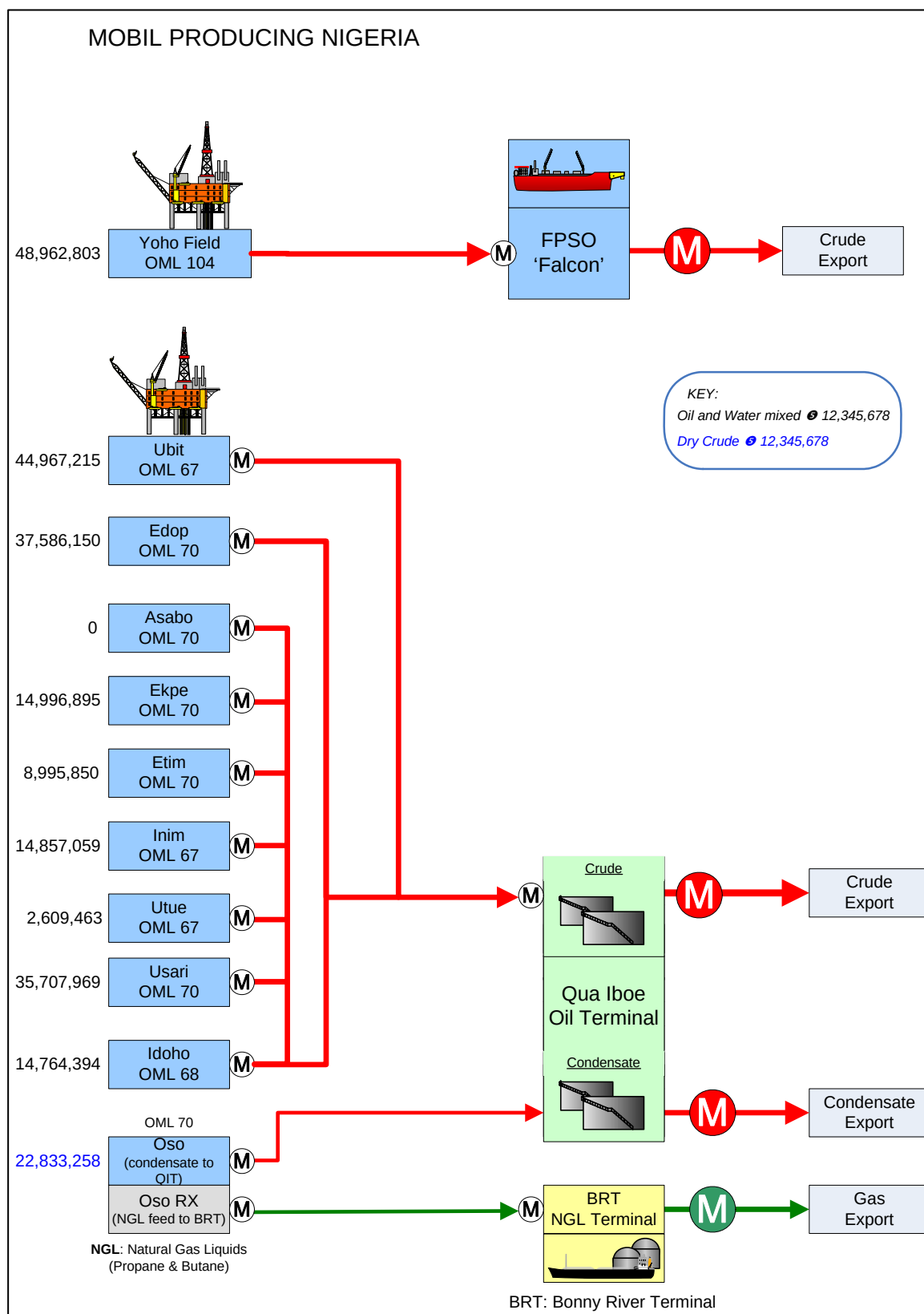












Part 3: Products Mass Balance

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1 Introduction and summary of conclusions

The purpose of the audit as regards the products mass balance was to prepare and present hydrocarbon (oil and gas) balances relating to 2005, at depot, area and national level, by product type and in total.

Our conclusions are:

- 1 the quality of data available from PPMC seems not to support this kind of analysis, due partly to shortcomings in measurement procedures (Appendix G) and partly to the lack of a mainstream system for producing regular mass balance reports for management purposes;
- 2 the data PPMC provided indicates the following losses in the system during 2005, with an estimated value of \$239 million:

Product	Volume Gain / (loss) Tonnes	Estimated value US\$ m
PMS	(287,297)	(179.6)
DPK	(150,610)	(66.7)
AGO	13,818	7.3
Total		(239.0)

- 3 The cause of the losses has not been identified. It could include pipeline vandalism, leaks, measurement error, theft but PPMC has not provided analysis of incidents.
- 4 We previously recommended steps that PPMC should take to improve their capacity to report to NEITI and also for management purposes. It should be noted that our recommendations were made at the conclusion of the NEITI 1999-2004 audit, at which time it would have been too late for PPMC to take any action that would improve the 2005 situation; accordingly, the recurrence of these findings and recommendations is unsurprising.

2 Audit Process

Since the 1999-2004 Audit, PPMC has been working on the mass balance template structure that was discussed during the preparations for that report. The process is not complete and the control templates are still evolving.

A large amount of data is required to control the product importation system from day-to-day and it should not be necessary for audit purposes to present all the data. More important is to fairly represent the situation in a format that is readily understood by the external stakeholders – in particular civil society.

Since these new operating templates are not yet populated with 2005 data, the 2005 audit prepared a simplified version for audit purposes (see appendix D for data returns). The structure and logic is as follows:

There is one sheet for each depot – ideally this should be completed by the depot itself, based on the depot records.

Each sheet is divided into three sections, one for each product (PMS, AGO and DPK). Each section represents the stock balance for that product during the year:

- o Opening Stock
- o Transfers in Pipeline (indicating where the product came from)
- o Transfers in – Road
- o Depot Sales
- o Transfers out – Road
- o Transfers out – Pipeline (indicating where the product was sent)
- o Unaccounted losses/gains (a calculated figure)
- o Closing Stock

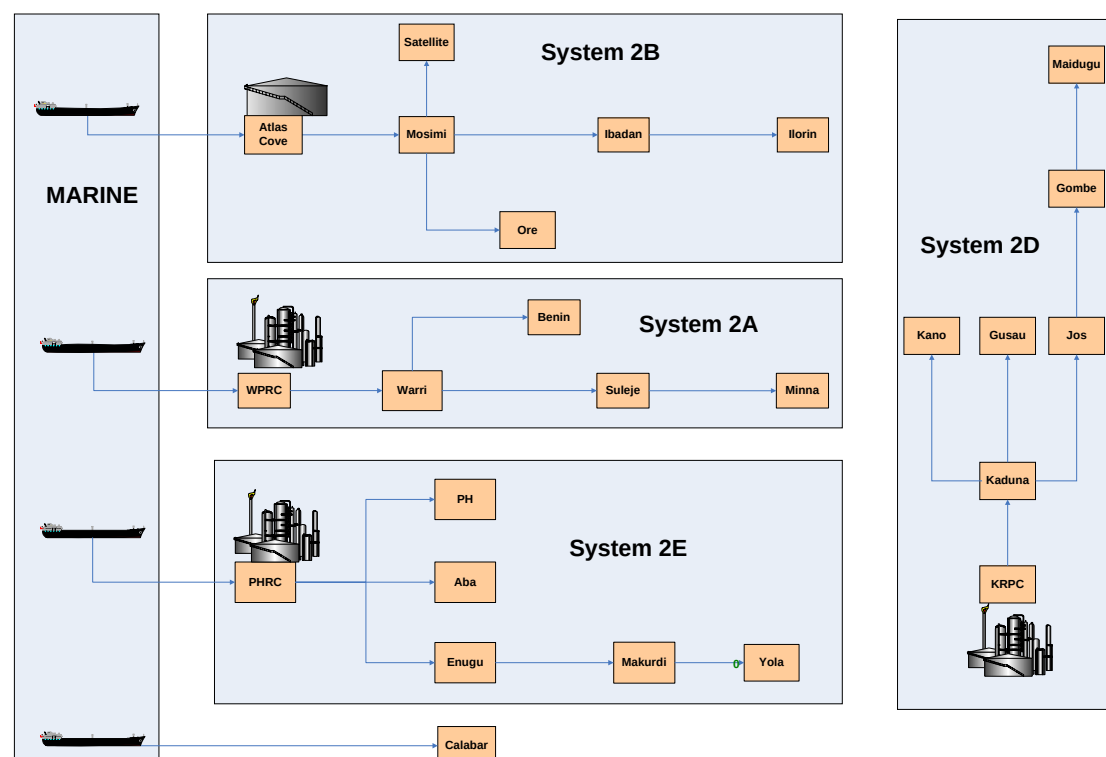
Since the depots are the only measuring points in the products network, pipeline losses/gains between depots are calculated by comparing the amount sent from depot A to depot B with the amount received by Depot B from Depot A. Pipeline stock is assessed by the volume of pipe full of product at the time the stock is audited. Of necessity this will be an approximation, but for guidance, an 8" diameter pipe will hold approximately 24.5 tonnes/km of PMS whereas a 16" pipe would hold nearly 100 tonnes/km.

3 System Overview

The products system consists of four interconnected subsystems:

- (a) Marine: imports product; delivers to depots/refineries; receives product from refineries; and sells to 3rd parties.
- (b) Refineries: deliver product to depots and also to marine for sales and transfer to Calabar depot.
- (c) Depots: 21 depots receive product (via pipeline) and sell to 3rd parties, or pass product on to other depots.
- (d) Pipelines: 4 pipeline systems connect the depots. Although there are interconnections between the pipeline systems, they can be treated as separate, as shown.

Figure 1: Overview of PPMC Products Pipeline Network



The total quantity of product entering the system is derived from the Schedule of Product Imports and the Refinery Production figures. The total quantity of product leaving the system is the sum of depot sales plus the sum of marine sales to 3rd parties.

4 Product Importation

PPMC provided a schedule of product imports (see Appendix D). Only PMS and DPK were imported by PPMC during 2005. From this we have summarised imports by Supplier sorted by quantity of imported product.

Overall the totals reconcile with the totals on the PPMC mass balance, however, from the schedule it is not clear whether this is the complete list of imports. For example:

- (a) The schedule appears to relate to payments, not shipments
- (b) It does not indicate actual discharge dates
- (c) There is one shipment that appears to relate to 2003 (PV 1733364)

PPMC should clarify this.

Table 1: Summary of Product Imports by Supplier

IMPORTS				
Product (tonnes)				
SUPPLIER	DPK	PMS	Total	%
TRAFIGURA	157,359	747,318	904,676	15.3%
NAPOIL	169,812	722,080	891,893	15.1%
VITOL	43,111	643,996	687,107	11.6%
CALSON	87,723	561,178	648,901	11.0%
GLENCORE		555,891	555,891	9.4%
ADDAX	26,440	458,999	485,439	8.2%
ARCADIA	32,848	433,887	466,735	7.9%
TOTAL		435,682	435,682	7.4%
CHEVTEX		317,032	317,032	5.4%
SHELL		273,437	273,437	4.6%
BP OIL		202,270	202,270	3.4%
SHELLWESTERN		32,818	32,818	0.6%
Total	517,292	5,384,587	5,901,880	

No AGO was imported.

In 2004, it was observed that Vitol and Calson work together (indeed, Vitol has a 50% shareholding in Calson, the other 50% being held by NNPC). It is also noted that Trafigura is a partner with NNPC in Napoil. Neither Calson nor Napoil are financially particularly strong. In considering the concentration of supply, therefore, it is relevant to look through the joint venture structure and recast the table as follows:

IMPORTS				
Product (tonnes)				
SUPPLIER	DPK	PMS	Total	%
TRAFIGURA / NAPOIL	327,171	1,469,398	1,796,569	30.4%
VITOL / CALSON	130,834	1,205,174	1,336,008	22.6%
GLENCORE		555,891	555,891	9.4%
ADDAX	26,440	458,999	485,439	8.2%
ARCADIA	32,848	433,887	466,735	7.9%
TOTAL		435,682	435,682	7.4%
CHEVTEX		317,032	317,032	5.4%
SHELL		273,437	273,437	4.6%
BP OIL		202,270	202,270	3.4%
SHELLWESTERN		32,818	32,818	0.6%
Total	517,292	5,384,587	5,901,880	

5 Cargo Discrepancies

There is one PMS cargo from Trafigura "High Tide" (PV 1733634) that claims a quantity of 137,646 tonnes. Not only is this 100,000 tonnes more than most of the other cargoes, but also we believe the vessel in question has a capacity of just 45,018 DWT. Again this looks like an administrative/clerical error since the value of the cargo appears correct for an amount of 37,000 tonnes at around \$22m. Typical imported cargo volumes are around 30,000 tonnes.

PPMC should clarify this. Since it would account for a 100,000 tonnes volumetric error and bring down the total import volume from 5,384,587MT to 5,284,587MT. The following analysis however assumes the original number is correct.

6 Refinery Outputs

The following table summarises the refinery outputs of the three products. The destination of product transferred to PPMC is detailed in Appendix D.

Table 2: Summaries of Refinery Outputs

PMS tonnes	KRPC	WRPC	PHRC	Total
Opening Stock	15,384	25,152	48,891	89,427
Production	388,173	674,315	675,602	1,738,090
Imports to refinery		225,251	524,500	749,751
Total	403,557	924,718	1,248,993	2,577,268
Transfer to PPMC	373,292	892,763	1,207,497	2,473,552
Closing Stock	28,747	31,955	41,496	102,198
Total	402,039	924,718	1,248,993	2,575,750
Gain/(Loss)	(1,518)	1	0	(1,517)

DPK tonnes	KRPC	WRPC	PHRC	Total
Opening Stock	15,774	24,272	31,550	71,596
Production	228,082	456,840	613,468	1,298,390
Imports to refinery				
Total	243,856	481,112	645,018	1,369,986
Transfer to PPMC	234,992	457,987	601,319	1,294,298
Closing Stock	8,864	23,325	43,699	75,888
Total	243,856	481,312	645,018	1,370,186
Gain/(Loss)	0	200	0	200

AGO tonnes	KRPC	WRPC	PHRC	Total
Opening Stock	15,017	20,455	46,488	81,960
Production	418,837	732,312	971,437	2,122,586
Imports to refinery				
Total	433,854	752,767	1,017,925	2,204,546
Transfer to PPMC	426,074	754,658	974,837	2,155,569
Closing Stock	7,780	11,449	43,088	62,317
Total	433,854	766,107	1,017,925	2,217,886
Gain/(Loss)	0	13,339	0	13,339

The production volumes in 2005 show a significant improvement in refinery performance over 2004 production.

7 Depot Mass Balance

7.1 Approach

The presentation of a depot mass balance is meaningful only if the underlying data is reliable. Our review of PPMC systems and procedures led us to be cautious in this regard:

1 In parallel with this mass balance exercise, a detailed technical assessment was undertaken of Depot Measurement procedures (see separate report AT Appendix G). This clearly concluded that the depot measurement processes are insufficient to guarantee accuracy and may be subject to significant error. In general, the only measurement likely to be accurate is the loading of road tankers (the sales figure in the template).

2 We had asked for the data to be prepared from depot records. PPMC provided the auditors with two versions of the mass balance. The numbers differed between the two, but there was no explanation or reconciliation of the differences. Given the question mark over the quality basic depot measurements, we have not explored the changes in detail. However, we summarise the changes here:

Type of difference	Depots affected
Data corrected/changed (3)	PH, Warri, Kano
Missing data added (2)	Mosimi. Satellite
Road Transfers removed (5)	Suleja, Minna, Gusau, Kaduna, Benin
No difference (12)	Atlas Cove, Ibadan, Ore, Ilorin, Jos, Gombe, Calabar, Maidiguru, Aba, Enugu, MKD, Yola

7.2 Data analysis

Data was requested for each month of 2005. Port Harcourt, Enugu, Yola, Jos and Gombi depots only returned quarterly data, hence it is not possible to provide a comprehensive month-by-month analysis.

Risk analysis suggests two types of discrepancy from this exercise.

Errors caused by incorrect measurements. These might accumulate over time, but should be corrected at least annually by the stock audit.

Data transcription errors: Since most of the source data is collected on handwritten forms, sometimes difficult to read and requiring calculations to be done, it is simple for errors to be made. (We have some examples on the small number of sample forms we collected during the measurement study). Though each form requires checking and countersigning/ authorising we have noticed that few PPMC depots follow the complete process in this regard.

Both types of error are extremely difficult to identify during a consolidation process without recourse to the original source data.

February 2005 data was not provided for Aba depot. This will introduce an error of some 10-20,000 tonnes in the PMS data.

Yola received 2,070 tonnes PMS, but no identified source. Similarly Gombe identify 1,703 tonnes of DPK received, but do not identify the source.

Some anomalies are difficult to understand. For example, the Kaduna schedule shows PMS quantities pumped to Kano in January, February and October, whereas Kano only received PMS during January and February and nothing for the rest of the year. This is a clear discrepancy that we would have expected to have been resolved at the monthly products movement reconciliation meetings.

No Road Transfers have been identified on the PPMC templates. Previously the 1999-2004 audit did identify road transfers between depots. PPMC should confirm the position for 2005.

7.3 Recommendations

- (a) The 1999-2004 Audit recommended that the mass balance for the network should be constructed monthly. In the light of the observations on measurement, the mass balance for the network should be constructed weekly. Since the numbers are unreliable, more frequent measures will even out discrepancies and anomalies will be spotted sooner, enabling prompt action to resolve problems. This should not be an onerous task, since each depot already provides both daily and weekly reports and PPMC Head Office has the basis of a set of templates for automatic consolidation.
- (b) Layout of depot reports should be reviewed. A format should be considered that tracks differences between what was expected to happen and what actually happened. This will assist the identification problems.
- (c) Some depots have a very low level of transaction. PPMC should focus attention on high throughput depots to embed good practices
- (d) Calabar should be treated as a distinctly different depot for the purposes of the Mass Balance. It is not connected to the pipeline network and receives all its product by coastal transfer either from Atlas Cove, Port Harcourt or Warri refineries.
- (e) The mass balance should be extended to show marine shipments explicitly between jetties.

8 PMS Balance

The following table shows the overall mass balance for PMS per PPMC return. Structurally there are four subsystems within the whole. The Marine system should be everything that is transacted by vessel. Product is imported by vessel, then either sold to 3rd parties, transhipped to PHRC and WRPC refineries or transferred to depots (Atlas Cove or Calabar). All these are measured transactions. The gain/loss on the system is the difference between all inputs to the Marine system (including opening stock) less all outputs (including closing stock).

Refineries source of product is opening stock, plus Production, plus imported product transferred from Marine. Refinery output is transferred to depots via pipelines and there is a refinery closing stock.

Depots receive product from Refineries (via pipelines) or marine (Atlas Cove, Calabar), sell to 3rd parties and may transfer product on to other depots. Depots have clear measurable opening and closing stock

The Pipelines system should represent the difference between what has been sent (from a Refinery or Depot) and what has been received. The pipeline stock position is calculated from the total pipe volume filled with liquid at a point in time.

PMS

(tonnes)	Marine	Depots	Refinery	Pipelines	Total
Opening Stock	215,418	311,034	89,427	96,241	712,120
Imports	5,384,587				5,384,587
Refinery Transfers		2,225,578		2,473,552	4,699,130
Production			1,738,090		1,738,090
Transfers from imports		2,644,736	749,751		3,394,487
Subtotal	5,600,005	5,181,348	2,577,268	2,569,793	15,928,414
Sales	2,126,149	4,884,414			7,010,563
Transfer to Refinery	749,751				749,751
Transfers to Depot/pipe	2,644,736		2,473,552	2,387,936	7,506,225
Losses/(Gains)		(3,192)	1,517	126,613	124,938
Closing Stock	79,369	300,126	102,198	55,244	536,937
Subtotal	5,600,005	5,181,348	2,577,268	2,569,794	15,928,414

Source: PPMC

The total column seems to indicate 15.9m tonnes of PMS in the system. This is not correct since there is double counting of transfers in the way the table has been constructed.

On the assumption the stock positions are correct, we have reinterpreted the base data supplied by PPMC and constructed the following balance for PMS:

PMS

tonnes	Marine	Refinery	Pipelines	Depots	Total
Opening Stock	215,418	89,427	96,241	311,034	712,120
Imports to Marine	5,384,587				5,384,587
Marine to Refinery	(749,751)	749,751			-
Marine to Depot (A Cove)	(2,644,736)			2,644,736	-
Refinery Production		1,738,090			1,738,090
Refinery to Ref Pipelines		(2,473,552)	2,473,552		-
Received from Ref Pipelines			(2,225,578)	2,225,578	-
Sent to other depots			5,253,807	(5,253,807)	-
Received from other depots			(5,355,081)	5,355,081	-
Sales	(2,126,149)			(4,884,414)	(7,010,563)
(Losses)/Gains		(1,517)	(187,697)	(98,082)	(287,297)
Closing Stock	79,369	102,198	55,244	300,126	536,937

Source: Re-cast from PPMC data

This layout clearly highlights the transfers between the subsystems and clearly shows how the internal transfers balance each other. This demonstrates the total system loss is more than double the 124,939 tonnes quoted by PPMC and is worth (based on their ex depot price of N55.21/litre and 117 N/\$) \$179,629,922.

It is not clear how Calabar is accounted. Logically, since Calabar receives all products by vessel, it should be part of the 2.644m tonne Marine transfers to Depot. However, that is fully accounted by the quantity received into Atlas Cove and transferred on to Mosimi.

9 Kerosene (DPK) Balance

DPK

Source: PPMC

(tonnes)	Marine	Depots	Refinery	Pipelines	Total
Opening Stock	94,969	144,329	71,596	59,436	370,330
Imports	517,292				517,292
Refinery Transfer	138,990	957,865		1,294,298	2,391,153
Production			1,298,390		1,298,390
Transfers from marine		138,990			138,990
Subtotal	751,251	1,241,184	1,369,986	1,353,734	4,716,156
Sales	704,529	1,098,646			1,803,175
Transfer to Marine				138,990	138,990
Transfers to Depot			1,294,298	1,096,855	2,391,153
Losses/(Gains)		32,920	(200)	83,771	116,491
Closing Stock	46,722	109,618	75,888	34,118	232,228
Subtotal	751,251	1,241,184	1,369,986	1,353,734	4,716,155

Source: PPMC

Our reinterpretation of the data, using the same principles as for PMS is as follows:

DPK

Re-cast from PPMC data

tonnes	Marine	Refinery	Pipelines	Depots	Total
Opening Stock	94,969	71,596	59,436	144,329	370,330
Imports to Marine	517,292				517,292
Refinery Production		1,298,390			1,298,390
Refinery to Marine	138,990	(138,990)			-
Refinery to A Cove		(138,990)		138,990	-
Refinery to Calabar		(18,354)		18,354	-
Refinery to Ref Pipelines		(997,964)	997,964		-
Received from Ref Pipeline			(981,520)	981,520	-
Sent to other Depots			613,190	(613,190)	-
Received from other Depots			(582,358)	582,358	-
Sales	(704,529)			(1,098,646)	(1,803,175)
(Losses)/Gains	(0)	200	(72,594)	(44,097)	(150,610)
Closing Stock	46,722	75,888	34,118	109,618	232,228

Source: Re-cast from PPMC data

This total system loss is more than the 116,491 tonnes quoted by PPMC and worth (based on their valuation of N42.50/litre and 117 N/\$) \$66,744,450.

There is a possible confusion in these numbers. 138,990 is shown as a transfer into Marine from pipelines and 138,990 is shown transferred from marine into Depots (confirmed as received at Atlas Cove by the depot). But there is no corresponding transfer OUT of marine.

Again it is hard to identify the Calabar supply of 18,354 tonnes, which should have been transferred from Marine.

10 AGO Balance

No AGO is imported. Instead, some refinery production is transferred to Marine and then sold to 3rd parties.

AGO

(tonnes)	Marine	Depots	Refinery	Pipelines	Total
Opening Stock	14,284	131,996	81,960	36,765	265,005
Imports					0
Refinery Transfers		1,347,654			1,347,654
Production			2,122,586	2,155,569	4,278,155
Transfers from pipeline	829,968				829,968
Subtotal	844,252	1,479,650	2,204,546	2,192,334	6,720,782
Sales	844,252	1,335,476			2,179,728
Transfer to Marine				829,968	829,968
Transfers to Depot			2,155,569	1,347,654	3,503,223
Gains/(Losses)	-	(21,575)	13,339	22,053	13,818
Closing Stock		122,599	62,317	36,765	221,681
Subtotal	844,252	1,479,650	2,204,546	2,192,334	6,720,782

Source: PPMC

Our reinterpretation of this data, using the same principles as for PMS is as follows:

AGO

tonnes	Marine	Refinery	Pipelines	Depots	Total
Opening Stock	14,284	81,960	36,765	131,996	265,005
Imports to Marine					-
Refinery Production		2,122,586			2,122,586
Refinery to Marine	829,968	(829,968)			-
Refinery to A Cove		(22,452)		22,452	-
Refinery to Calabar		(6,401)		6,401	-
Refinery to Ref Pipelines		(1,296,748)	1,296,748		-
Received from Ref Pipeline			(1,322,335)	1,322,335	-
Sent to other depots			324,411	(324,411)	-
Received from other depots			(313,594)	313,594	-
Sales	(844,252)			(1,335,476)	(2,179,728)
(Losses)/Gains	0	13,339	14,770	(14,292)	13,818
Closing Stock	-	62,317	36,765	122,599	221,681

Source: Re-cast from PPMC data

This reinterpretation confirms the figures in the PPMC table above. There was a “gain” in the system of 13,818 tonnes (valued at \$7,273,123). We would however question the likelihood that the Pipeline stock position has remained unchanged despite a throughput of some 1.5m tonnes.

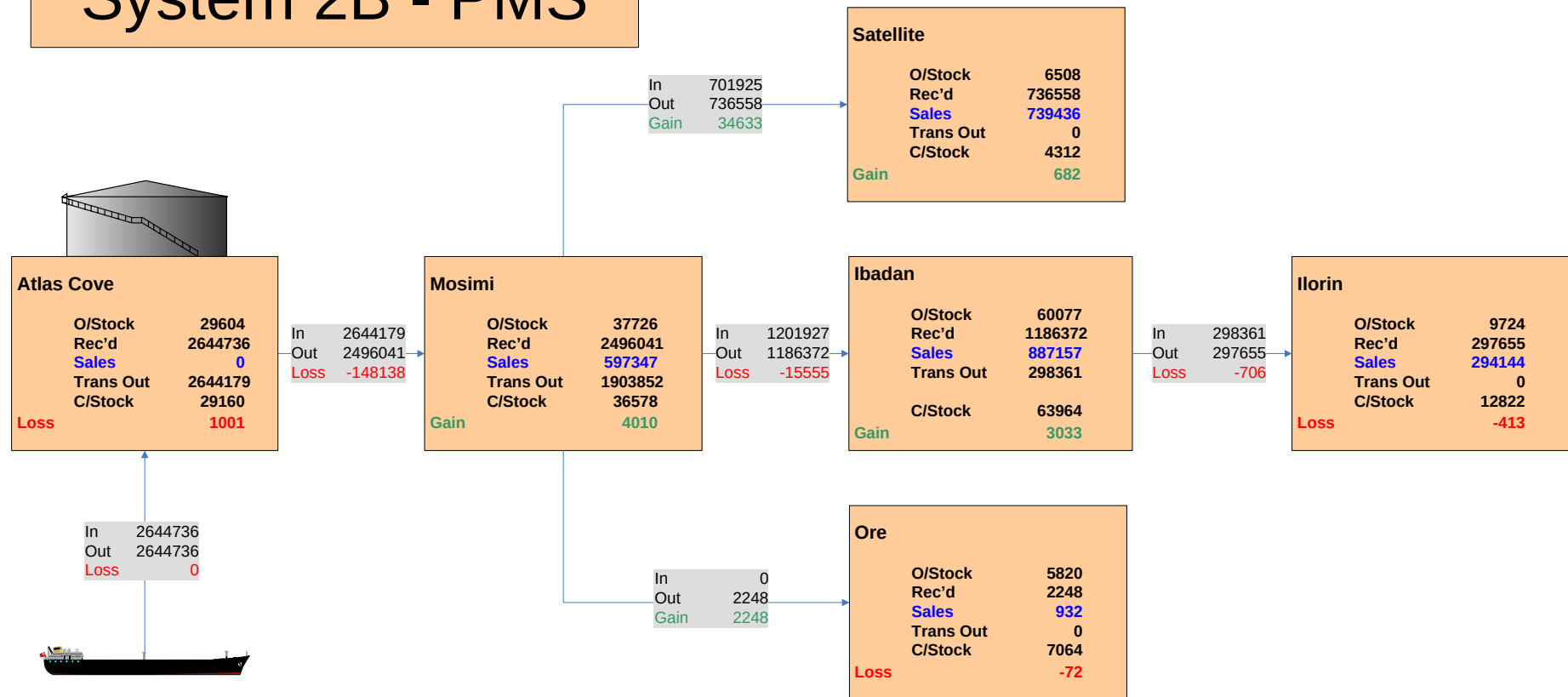
Attachment: Graphic representation of Pipeline flows.

The following pictures show the balance for each product in each of the four pipeline systems and the interaction with Marine.

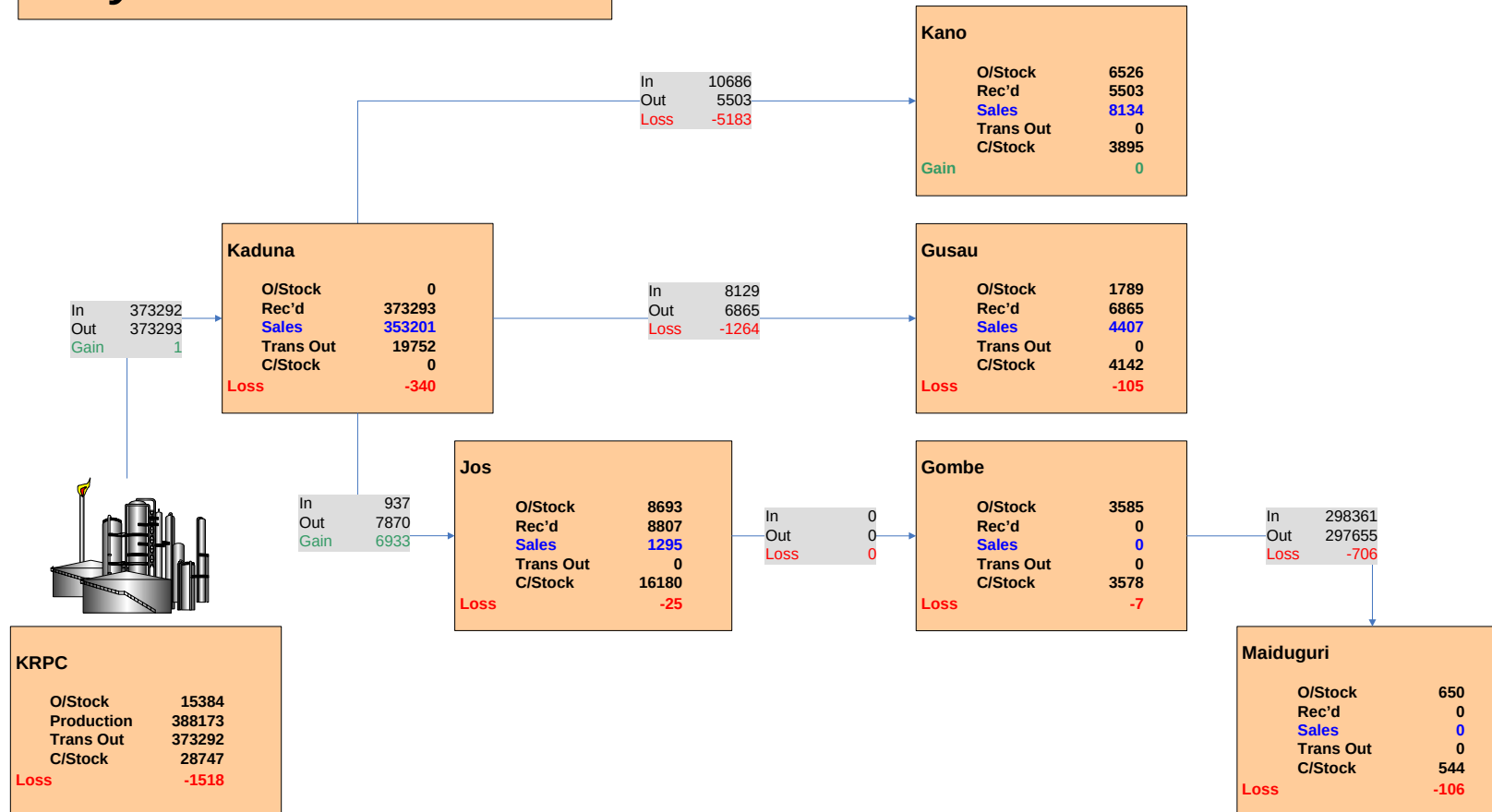
Each shows connections between the depots and the refineries and details the opening stock, transfers in, sales, transfers out and closing stock for each depot, as reported by PPMC. From this a gain/(loss) for each depot and pipeline section has been calculated.

It should be noted that the PPMC figures include some anomalies that remain unexplained. For example, on System 2B there is a reported gain of 5% on pipeline transmissions from Mosimi to Satellite. This would be unusual.

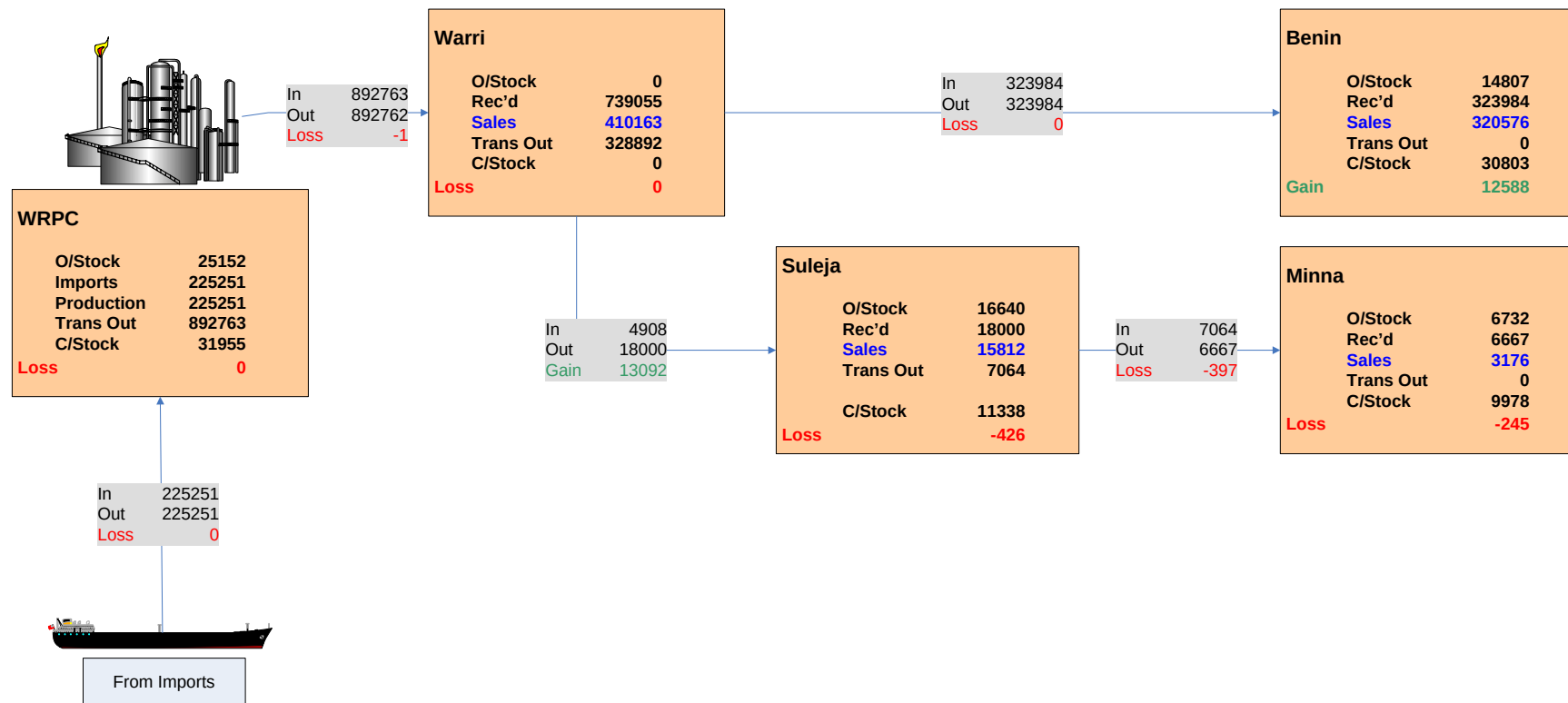
System 2B - PMS

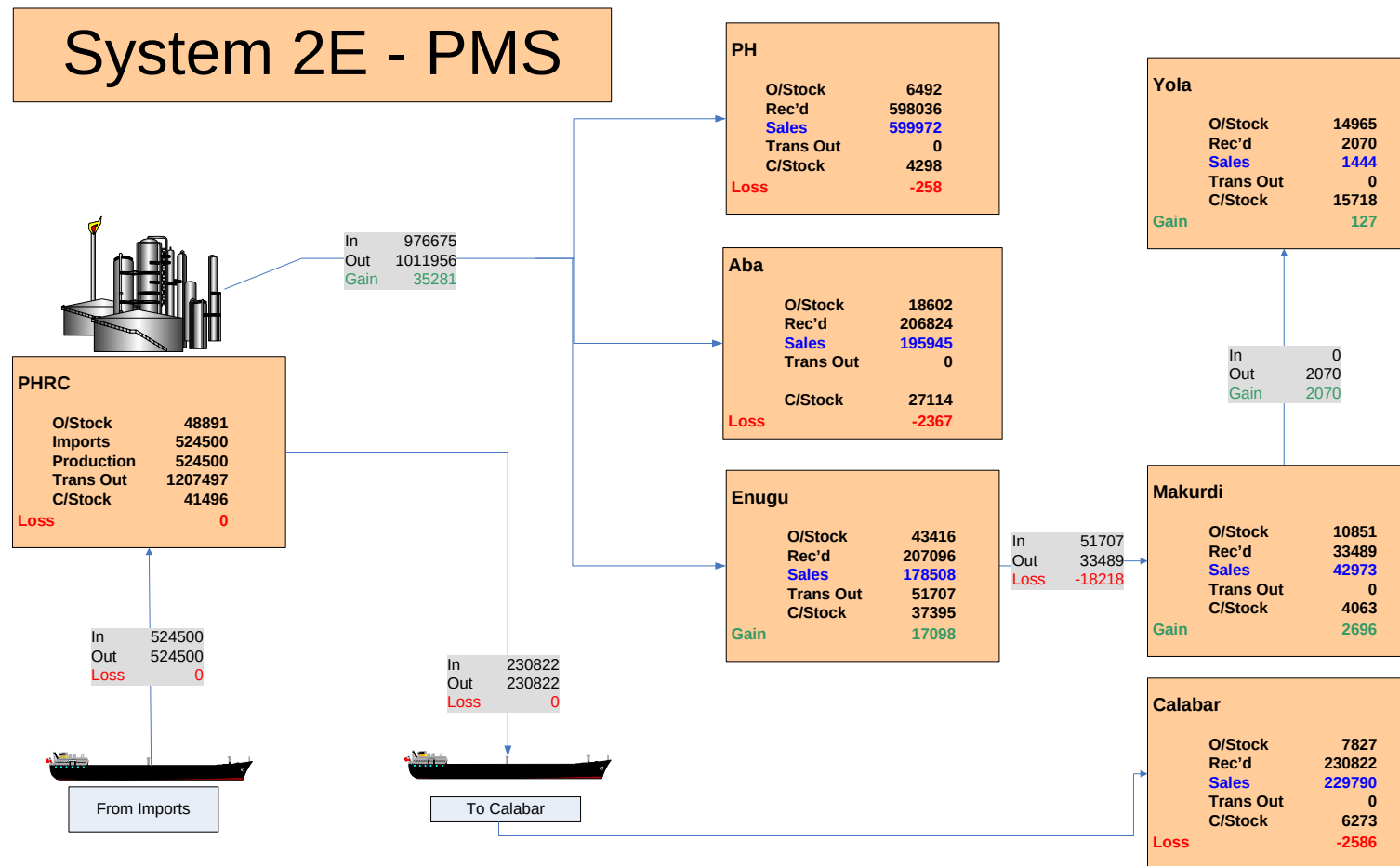


System 2D - PMS

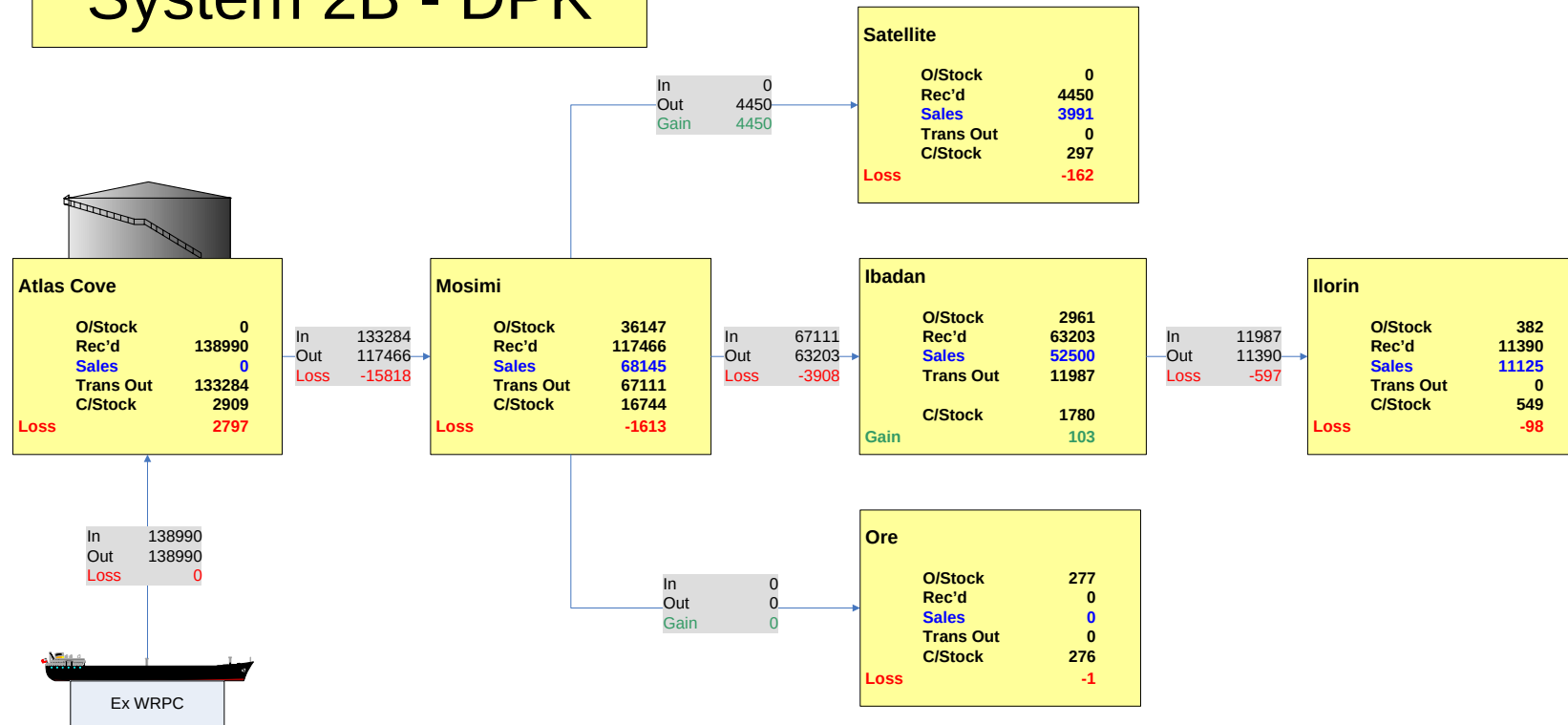


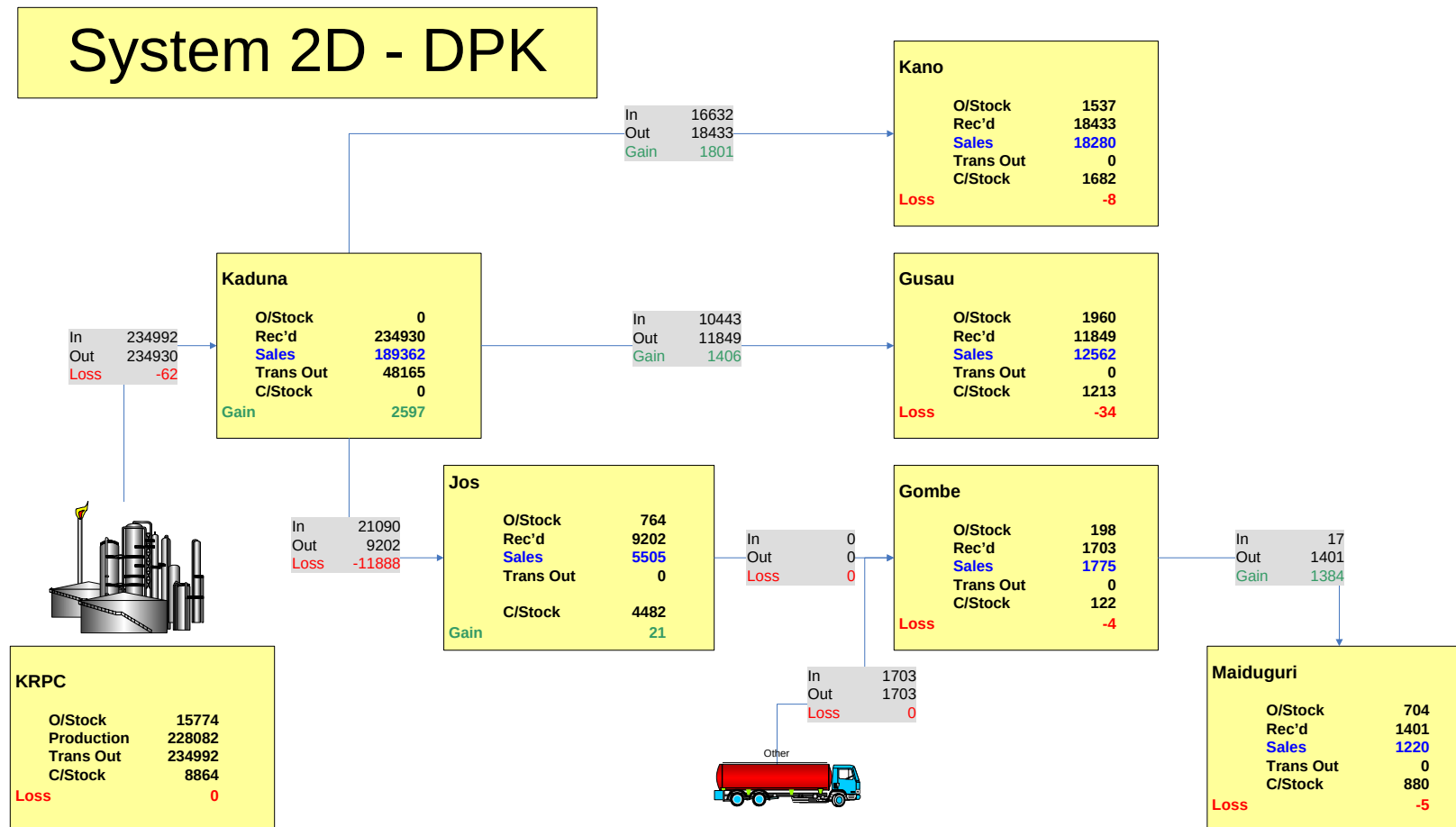
System 2A - PMS



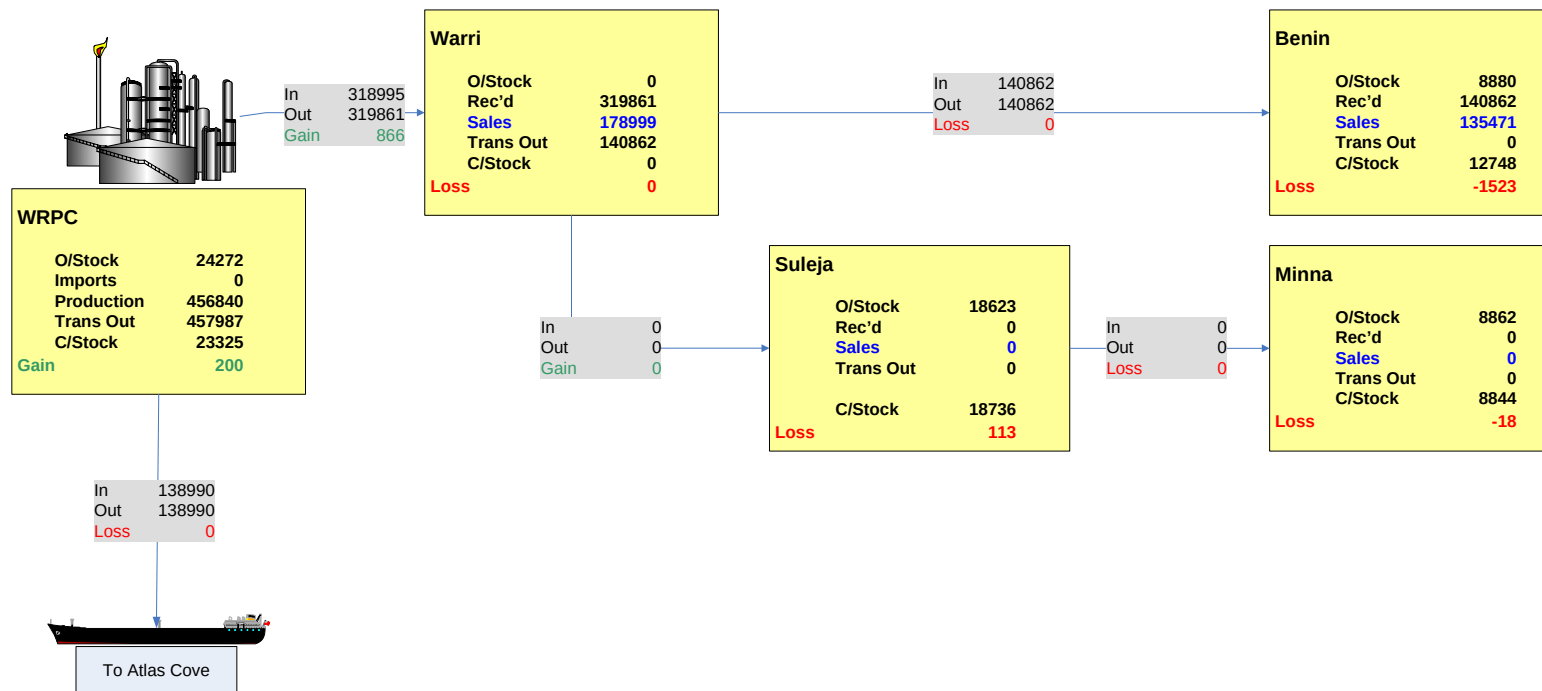


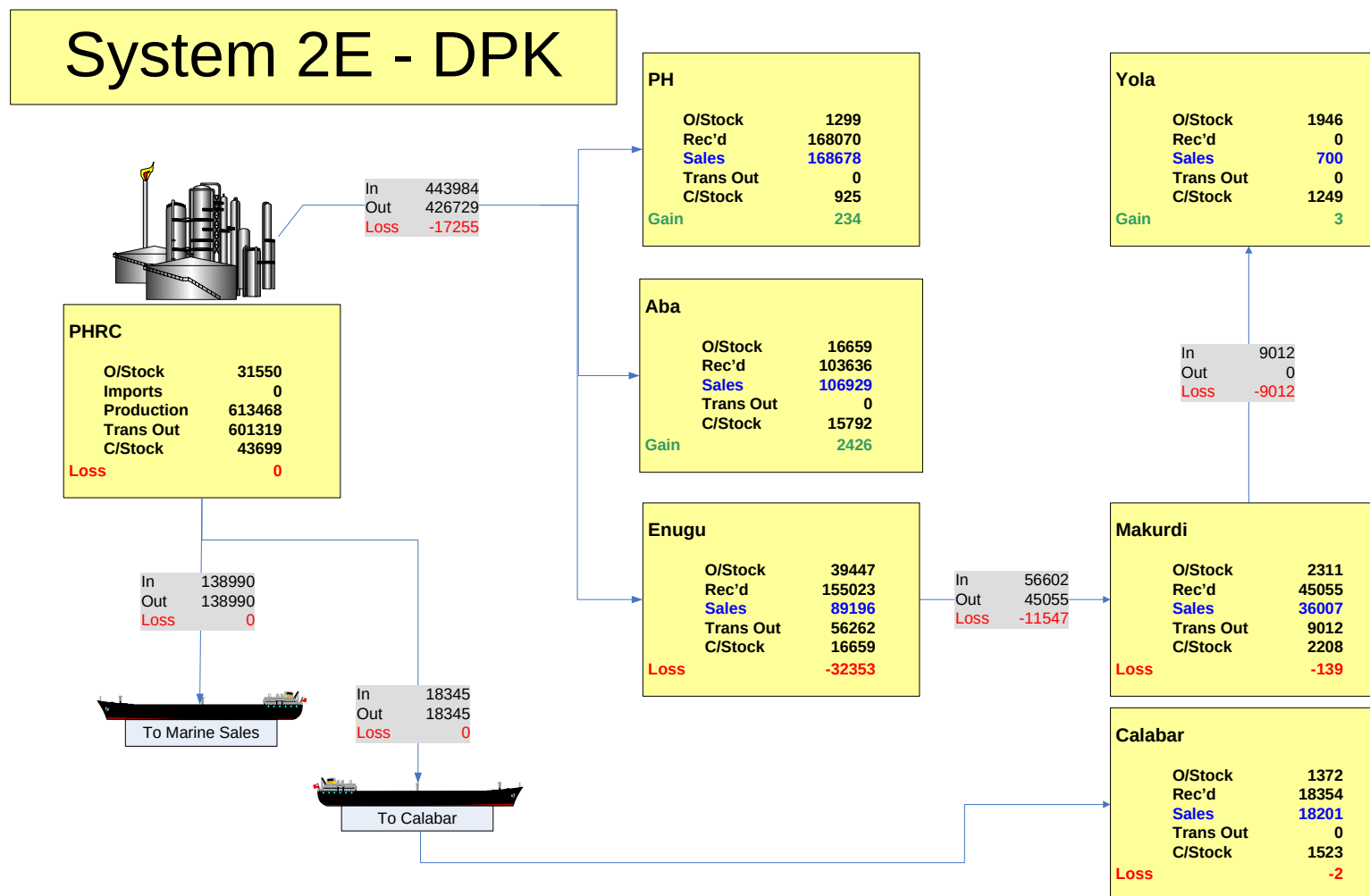
System 2B - DPK



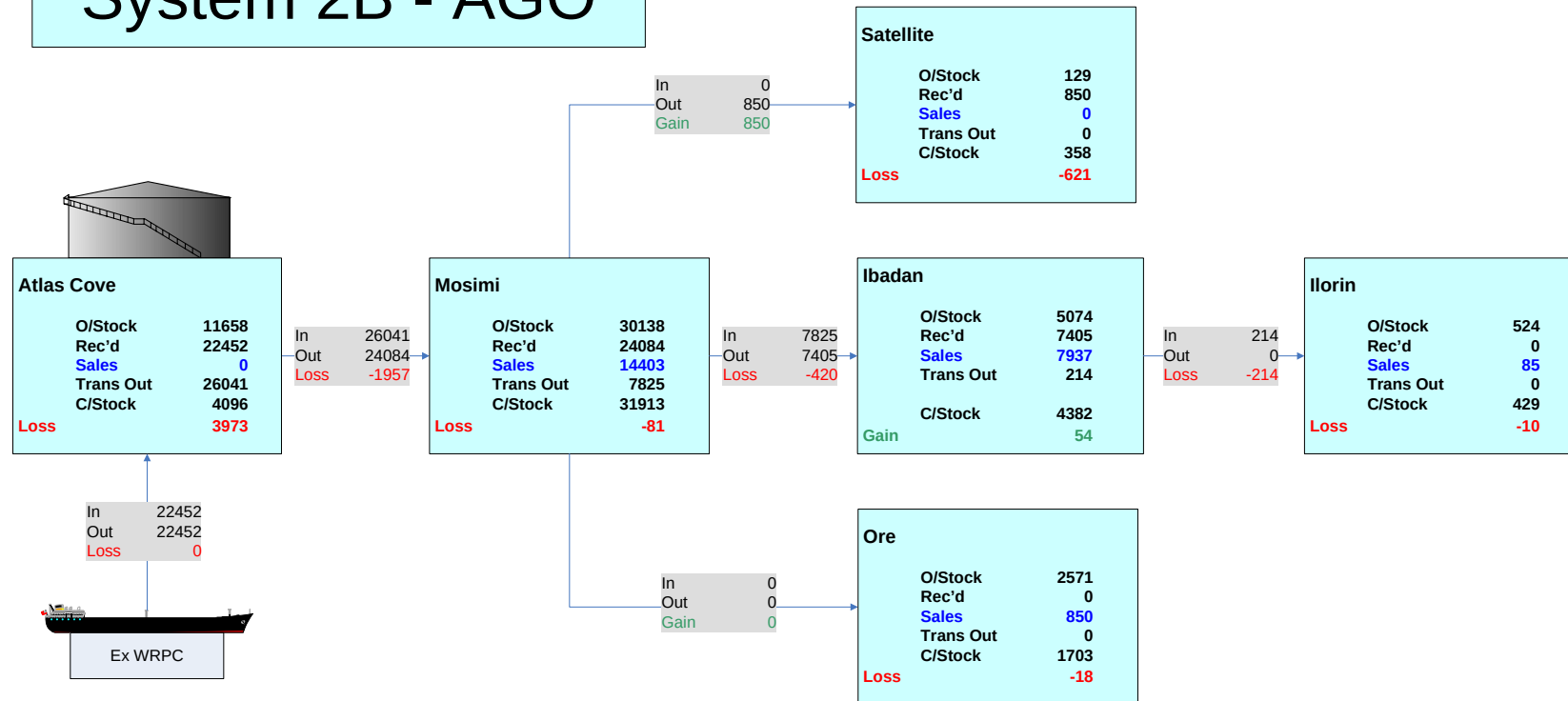


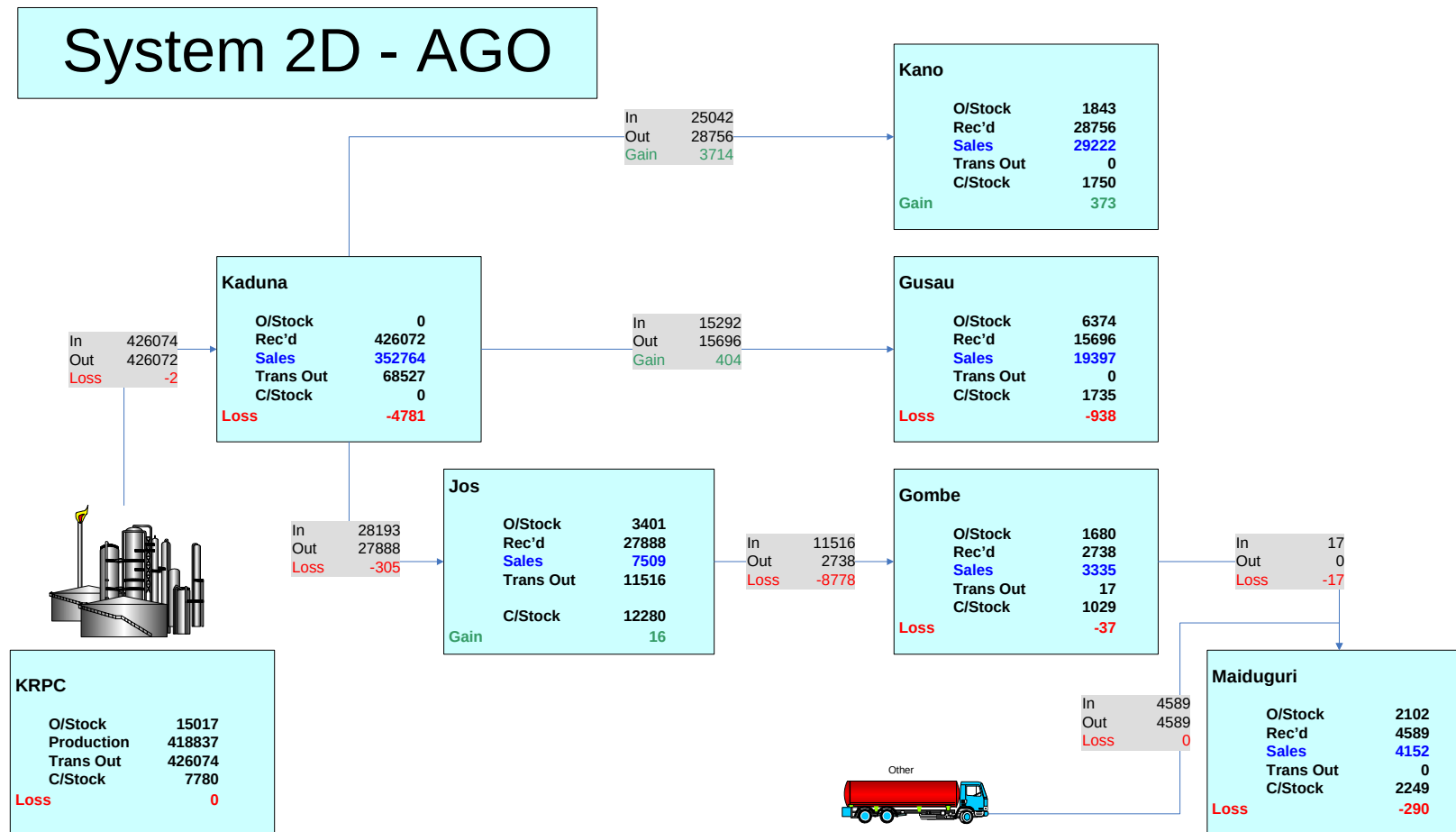
System 2A - DPK



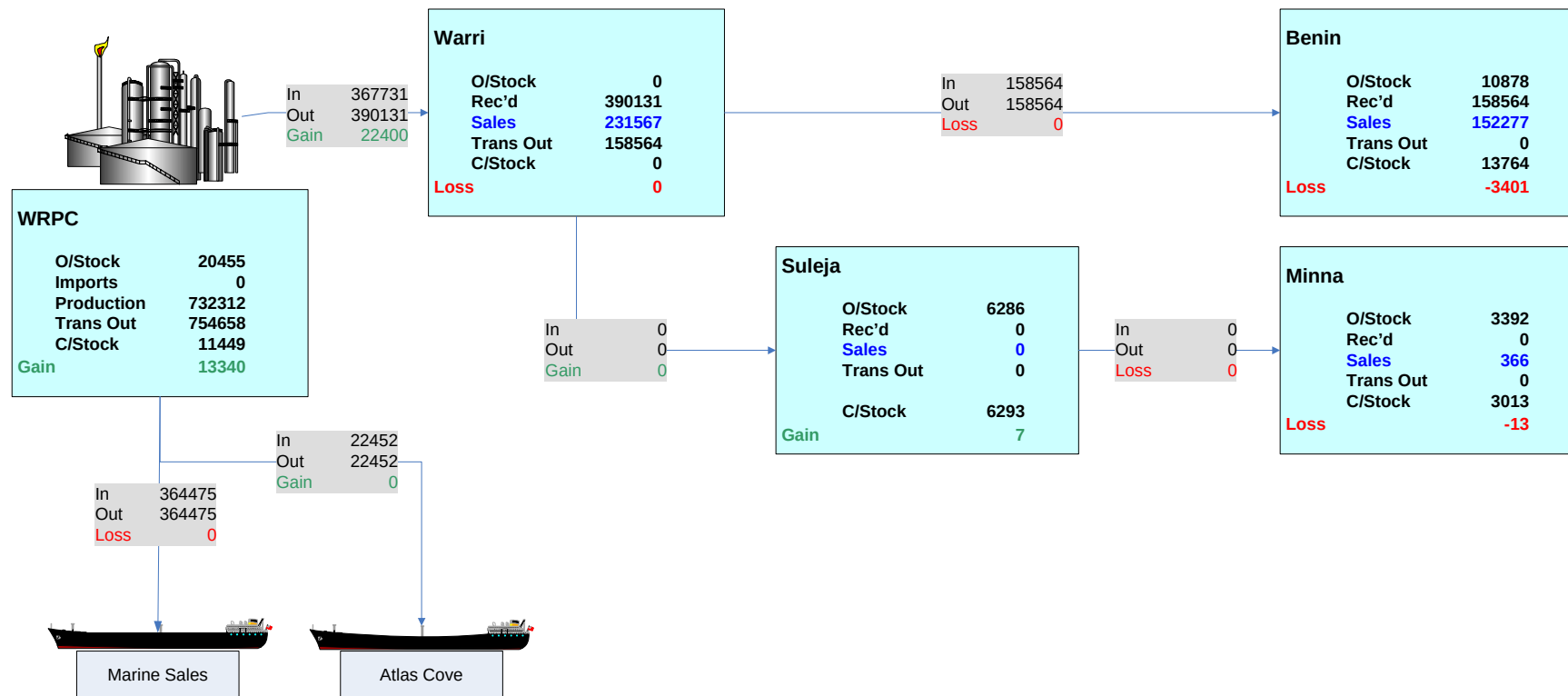


System 2B - AGO





System 2A - AGO



System 2E - AGO

