

Many of the PDO fields started production before or during the 1970's and **production declines** are apparent in a number of them. As mentioned, these declines have been countered by an aggressive drilling campaign, and this has helped maintain the PDO plateau production through the 1990's. The many infill wells did not always yield the additional reserves that were aspired. A striking example is seen in the Yibal field, where a massive horizontal infill well campaign did raise production, but now shows a decline towards an ultimate recovery that is not much different from that seen before, see Fig.1. A possible mild arrest of the decline may be evident from recent measurements. The lesson seems to be that many fields will yield additional recoverable volumes, but that they need sufficient time. The prevailing reservoir heterogeneities make gas-oil gravity drainage or induced/spontaneous water imbibition the only realistic option for further recovery. The associated time frames can hardly be accelerated.

4. The RSST have identified that lack of **reservoir understanding** is the single most important bottleneck to production increases and further oil development maturation. Good reservoir understanding requires a reliable and representative 3D reservoir model (first static, then dynamic) and the experience in many other operations in the Group is that the availability of **good 3D seismic** is key to such modelling. Spectacular results have been seen in a number of places making e.g. reservoir character or oil fill clearly visible. Many PDO teams claim that, due to the complex overburden (a number of strong reflective events) and due to the poor acoustic contrast at reservoir level, little use can be made of the available seismic in reservoir characterisation and 3D mapping. This opinion seems to be contradicted by experience in the Rima field, where it has been shown that dedicated re-processing (Cheats and van Gogh filtering) and close cooperation with Exploration Processing can yield much improved results. This should be pursued further to see whether similar results can be obtained in other fields.
5. There is **mis-alignment between individual field proved reserves and the corporate PDO submission**. The root cause for this has been that PDO have historically focused mainly on expectation reserves because these are the subject of intensive discussions with the Oman Government (and also the basis for reserves addition bonuses). Proved reserves estimates for individual fields were prepared but these have hardly been updated and they have now shrunk to unrealistic levels (see 6 below). Because of this, PDO have maintained corporate Group share proved total reserves as an independent entity, not linked to individual field volumes. This approach has not only caused problems with the audit trail but, more seriously, it allowed the Group proved reserves estimate to drift away from realistic levels, see 8 below.
6. **Probabilistic estimates** of STOIP and ultimate recoveries have been prepared by PDO prior to, and in early stages of field development. Recovery factor ranges were obtained from preliminary reservoir modelling. The probabilistic parameter ranges tend still to be based on early well data only, i.e. no adjustment has been made for subsequent dynamic STOIP and recovery determination from production performance. Hence, the current **proved vs expectation recovery ranges** are too wide for the current stage of field development. The 1999 reserves audit made the same observation. It is therefore disappointing to see that no progress has been made in this respect.

The conservative nature of the current field proved (P85) recoveries has been further exposed by progressing cumulative production from the fields. With proved and expectation ultimate recoveries fixed, the range between proved and expectation remaining reserves will widen with progressing production. This is clearly visible in Figure 2. Cumulative production has already overtaken proved ultimate recovery in some fields, with the result that these fields now carry negative proved remaining reserves, which is of course impossible. Examples are Rima, Sayyala, Wafra and Runib.

Group reserves guidelines state clearly that field / reservoir reserves estimates should be made separately for developed (no further activity, or NFA) and undeveloped reserves. The latter must be project based, i.e. they must be associated with clearly identified future development activities (wells, facilities). Estimation of total recoveries based on (largely assumed) recovery factors is archaic and is considered indefensible with the current state of petroleum engineering technology.

Proved developed reserves should be derived in a deterministic manner, using reservoir model simulations and production trend extrapolations. Proved undeveloped reserves should be evaluated in the same manner, using a low case model realisation. This practice should result in proved undeveloped reserves growing towards expectation levels with progressing field maturity, see Fig. 2.

7. **Expectation developed reserves** are generally, and correctly, derived from well and cluster decline analysis (through Oil Field Manager software) or from reservoir simulation models. The origin of the Group share proved developed estimate was not clear (poor audit trail, see below), but its volume seems broadly in line with the expectation NFA forecast, cut off at the end-of-licence in 2014. This is in accordance with Group guidelines. However, the link between Group share / corporate proved reserves and individual field estimates should be re-established.
8. There is a serious flaw in the corporate **total proved reserves** estimate (and, by implication, in the undeveloped reserves estimate) in that this estimate was not reviewed when the PDO oil production started to decline rapidly from 2000 onwards. Group share reserves should be producible within the current licence period (ending in 2014) and the achievement of production of the stated volumes in that time period has rapidly become unlikely.

The majority of undeveloped field reserves are associated with identified projects. However, many of these are notional or highly notional, while others do not even have a forecast associated with them in the Business Plan. There are of course more mature projects, but many of these are recognised as needing further work or re-work in order to become matured towards the required VAR3 (or FID) level. Even some projects/volumes based on FDPs from the late 1990's, which did pass VAR3 earlier, are now seen as out of date because of subsequent well and field performance. The estimate made by PDO and the SRRT is that 80-90% of the presently identified undeveloped reserves are yet to pass through the VAR3 stage. This means that these volumes do not fulfil present Group and SEC guidelines. It is accepted that the latter have tightened over the last three years (from 'defined' projects to VAR3) and thus further increased the exposure.

The main reason for this regrettable situation is that proper modern static and dynamic modelling has received insufficient attention in PDO in recent years. Much attention was diverted towards short-term activities to provide new well proposals. The situation is now being addressed through an urgent and aggressive study programme.

The Group share total (i.e. undeveloped) reserves booked at 1.1.2003 have thus been seriously overstated. A preliminary estimate by PDO is that of the 907 MMstb (Group share) booked at 1.1.2003, some 400 MMstb are exposed as insufficiently mature according to present Group guidelines.

The impact of this overstatement of reserves is somewhat reduced by the fact that discussions between PDO and the Oman Government towards an extension of the current production licence are currently in progress and that a Heads of Agreement is expected before the end of 2003. A formal extension agreement could then be signed during the first half of 2004. This should bring some 300 MMstb (230 MMstb developed, 70 MMstb undeveloped) into the Group reserves portfolio.

9. It has been noted during the audit that PDO carry a number of projects with **positive expectation reserves but zero proved reserves**. These volumes relate to projects and exploration discoveries, whose development plan is not yet sufficiently mature to merit the booking of proved reserves. The expectation volumes have been agreed with the Oman Government and reserves addition- and exploration bonuses have been received for them. The Group guidelines state clearly that expectation reserves can only be booked if the associated projects fulfil the conditions for proved reserves. If the latter is not the case, the expectation volumes should be booked as SFR. This should be addressed in the forthcoming submission.

10. The consistency between reserves and Finance was good. There was full agreement between the 1.1.2003 submissions for reserves and for annual production through Ceres/FIRST, without any corrections being required.

The verification of the correctness of proved developed and proved total reserves used for UOP asset depletion calculations was not relevant in the case of PDO, because UOP asset depletion has not been applied in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the PDO profit margin and for PDO tax returns. Shell Group accounts returns are prepared by Shell Oman Trading (SOMANT) and they do not declare any share in the PDO assets.

PDO accounts are managed with depreciation through the abovementioned 5-year profile. This is not in accordance with international accounting practices, which require **UOP depletion**, based on proved total and proved developed reserves. This has led to qualifications in external auditor reports, which the Oman Government now want to see removed. Hence, PDO will need to start maintaining proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves. In view of the current state of PDO's proved reserves estimates (both corporate and by field), PDO have considered it not realistic to start with the new method of UOP accounting per 1.1.2004. A start per 1.1.2005 was seen to be the earliest possible as it would be desirable to avoid major swings in individual field reserves and asset values due to the necessary corrections to be applied during 2004. This view is fully supported.

Following the implementation of the new method of asset accounting, PDO will be required to re-state their accounts back to 2000. The intention was to do this on the basis of the 1.1.2005 volumes, correcting back only for annual production. The auditor recommendation is to include annual transfers from undeveloped to developed volumes (i.e. development activity) as well, since without this correction the earlier proved developed reserves would become too large.

11. By way of **audit trail**, PDO issue an annual ARPR report, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format of the report seems somewhat cumbersome (duplicated data and unnecessary data, e.g. depletion rates, high estimates) and it could benefit from a simplification.

There is no note or report describing the basis or background for the Group share reserves submission. There is a spreadsheet, but this is not very accessible. Individual field proved reserves in the 1.1.2003 submission are clearly wrong (e.g. larger than expectation volumes and also larger than full-field-life proved reserves). The submission listed changes in the 'Improved Recovery', 'Extensions and Discoveries', and 'Transfers from Undeveloped to Developed' categories, but there was no audit trail to link this back in a quantitative manner to individual fields. The audit trail for PDO's shell share proved reserves is thus extremely poor. Guidelines for a proper audit trail are published on the EPB-P website ('Planning'/Reserves', to be moved to a new EPS website

in due course) and these should be followed. What is needed is a set of tables as presented in Att.2, with a brief note describing the source of the constituent data.

It was noted that there seems to be no effective central PDO library and field teams tend to keep project reports in personal filing cabinets. The RSST reported instances where documents had to be obtained from the Ministry because no copies could be found within PDO, following the temporary abandonment and re-assignment of the Fahud field team. This clearly an undesirable situation and corrective measures should be undertaken.

12. The auditor's suggestion for the way forward is as follows:

- In view of the short period left to end-2003, continue booking the present proved developed and proved total Group share reserves volumes in the 1.1.2004 submission, correcting only for 2003 production and for transfers from developed to undeveloped. Total proved reserves replacement ratio should thus be -100%.
- Conclude the production licence extension agreement with the Oman Government during 2004
- Book the proper sum of full life cycle proved developed reserves for all fields and proved undeveloped reserves for all projects fulfilling Group reserves criteria per 1.1.2005. This would require the maturation of at least some 200 MMstb of proved project volumes, to obtain a 100% proved reserves replacement ratio over 2004, see Table 1 below. Group share reserves should be a straight 34% of PDO oil reserves.
- It is suggested to invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify with him the status of the of the proved developed and proved undeveloped reserves portfolio.

Group share total proved reserves 1.1.2003 (MMstb)	907
2003 Production	-87
Group share total proved reserves 1.1.2004 (MMstb)	820
Group share total proved reserves 1.1.2004 (MMstb)	820
Overstatement 400 MMstb	-400
Transfer from beyond-licence	+287
New matured proved reserves	+200
2004 Production	-87
Group share total proved reserves 1.1.2005 (MMstb)	820

Table 1 – Progression of PDO Group share proved reserves during 2003 / 2004

### Recommendations

1. Pursue the possible improvements in reservoir characterization and modelling that may be obtained from dedicated seismic re-processing (cf Rima).
2. Declare proved developed as equal to expectation developed reserves in fields where there is either a good simulation history match or where there is a well-defined decline rate extrapolation. New fields and reservoirs with neither of these should be assigned a conservative (low case) value for proved developed reserves.
3. Prepare proved and expectation estimates of undeveloped reserves by individual project and by field. Proved estimates should preferably be based on low case simulation model realisations and should be seen to be growing towards expectation levels with progressing field cumulative production. Projects should be ranked according to their maturity, e.g. 'firm' (VAR3/FID), 'mature' (documented FDP), 'possible' (VAR2) etc.
4. Invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify the status of Group share proved developed and proved undeveloped reserves.
5. In the re-statement of PDO accounts for years back to 2000, correct the 1.1.2005 volumes back to earlier years by adding annual production and by subtracting annual transfers from undeveloped to developed reserves.
6. Classify projects with expectation reserves but zero proved reserves as SFR in the 1.1.2004 submission.
7. Improve the audit trail for the Group reserves submission by following the guidelines for on the EPB/Planning/Reserves website.
8. Consider the installation of a central library where properly indexed copies of reports and meeting notes (e.g. with the Ministry) can be stored and kept.

RJW00950017

## YIBAL FIELD - RATE vs CUM. PRODUCTION

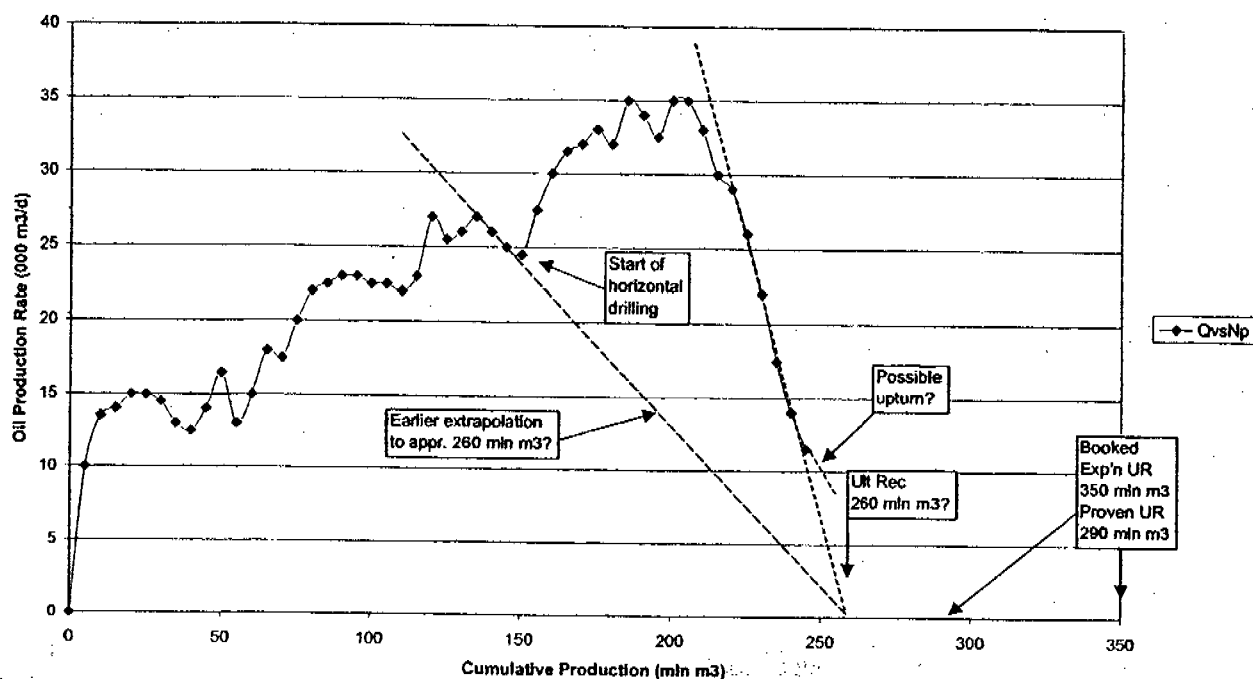


Figure 1 - Yibal field oil rate decline versus cumulative production

## PDO 1.1.2003 Total Reserves

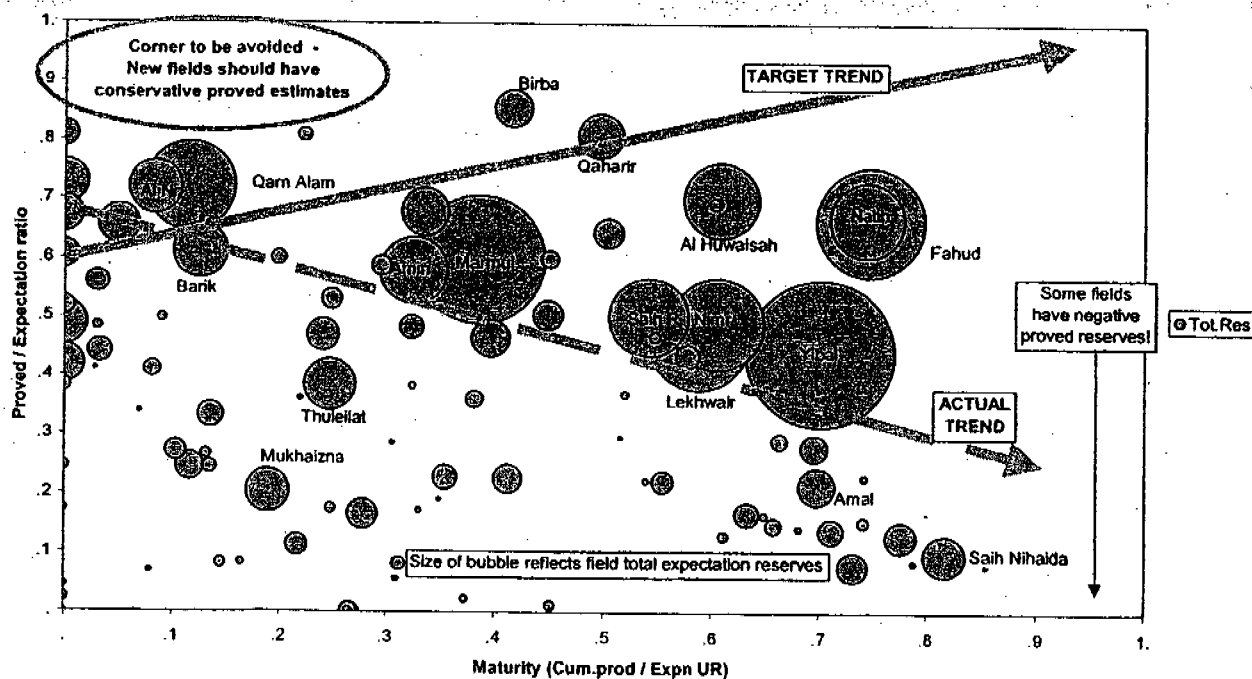


Figure 2 - Ratio of Proved / Expectation Reserves versus progressing field maturity

FOIA Confidential  
Treatment Requested



PDO		Proved Oil Reserves Changes 2002 (100%, mln m3)													
Field	Prov. Res. 1.1.2002	Revisions/ Reclass.	Improved Recovery	Extens./ Discov's	Purchase in- place	Sales in- place	New Develop Reserves (Transf. Und. to)	Production 2002	Prov. Res. 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10% m3)	Net Shell Equity 1.1.2003 (10% m3)	Comments
Proved Developed Reserves															
YIBAL	15.76	0.00						5.00	10.76	136.22%	34 %	136.22%	21.47	14.66	
FAHID	40.15	0.00						3.56	36.59	16.69%	34 %	16.69%	6.78	5.18	
MARMUL	13.69	0.00						2.18	10.91	64.97%	34 %	64.97%	8.50	7.09	
LEIGHWAI	21.17	0.00						4.91	16.26	45.28%	34 %	45.28%	9.68	7.36	
HATH	17.30	0.00						1.79	16.11	28.5%	34 %	28.5%	5.10	4.59	
NIMR	12.06	0.00						4.50	7.55	61.33%	34 %	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.59	-1.38	-97.19%	34 %	-97.19%	-0.20	1.34	
AL HUWASAH	8.31	0.00						1.79	6.52	27.15%	34 %	27.15%	2.26	1.77	
SAH RAWL	9.03	0.00						2.32	6.71	48.87%	34 %	48.87%	4.47	3.39	
QARN ALAM	0.84	0.00						0.09	0.76	32.01%	34 %	32.01%	0.22	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.69%	34 %	30.69%	16.84	11.63	
Prov. Dev. Res. (mln m3)	193.96	0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.57%	34 %	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	36.39	0.00						36.39	15.2%			15.2%	5.38	5.38	
FAHID	8.79	0.00						0.79	291.9%			291.9%	2.32	2.32	
MARMUL	36.81	0.00						36.81	26.91%			26.91%	9.68	9.68	
LEIGHWAI	5.64	0.00						5.64	69.24%			69.24%	3.34	3.34	
HATH	1.78	0.00						1.78	42.58%			42.58%	0.76	0.76	
NIMR	12.95	0.00						12.95	37.18%			37.18%	4.67	4.67	
RIMA	0.03	0.00						0.03	1830.13%			1830.13%	0.68	0.68	
AL HUWASAH	12.51	0.00						12.51	36.78%			36.78%	4.60	4.60	
SAH RAWL	8.15	0.00						8.15	43.56%			43.56%	3.55	3.55	
QARN ALAM	27.30	0.00						27.30	32.16%			32.16%	8.79	8.79	
Other Fields	65.67	0.00						65.67	44.05%			44.05%	37.74	37.74	
Prov. Under Res. (mln m3)	225.80	0.00	0.00	0.00	0.00	0.00	0.00	225.80	36.05%			36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	82.41	-4.42					0.00	15.22	62.77	62.77					
Proved Total Reserves (10% m3)	163.81	-4.42	0.00	0.00	0.00	0.00	0.00	15.22	144.17	144.17					
1.1.2003 Submission															
Prov. Dev. Res.	85.80	4.92					7.27	15.22	62.77	62.77					No 1.1.2002 field data available
Prov. Totl Res (10% m3)	162.30	-2.74	8.34	1.43				15.22	144.17	144.17					No audit trail for Transfers undevel'd to dev'd, Extensions/Discoveries and Improved Recovery
Conversion factors used by PDO: 1 m3 = 1 m3 1 scf = 0.0283 m3															
Conversion factors used by SIEP: 1 stb = 0.159 m3 1 scf = 0.0283 m3															

## Unknown

**From:** Van De Vijver, Walter SI-MGDWV  
**Sent:** 16 November 2003 12:16  
**To:** Boynton, Judith G SI-MGDJB  
**Subject:** FW: 2003 RRR Review

Judy,

Some early warning...

We now have two unsatisfactory reserves audits to deal with (I have not seen the report yet):

Oman 400 MMbo, Shell share "overbooking"

Nigeria 720 MMbo, Shell share reserves without any development plans (should be de-booked)

Both countries have had the following:

- history of aggressive reserves bookings "stimulated" by reserves fees in our NIAT "contract" (Nigeria stopped in '99 after new MoU)
- lack of technical staffwork (no quality reserves maturation plans)
- countries not delivering on production promises and hence reserves deferred until after license expiry date

All highly embarrassing for a company that is supposed to be conservative!

Regards,  
Walter

-----Original Message-----

**From:** Pay, John JR SIEP-EPS-P  
**Sent:** 14 November 2003 12:09  
**To:** Van De Vijver, Walter SI-MGDWV  
**Cc:** Bell, John J SIEP-EPS; Coopman, Frank F SIEP-EPP; Darley, John J SIEP-EPT; Percival, Iain IDR SIEP-EPT-OE-HL  
**Subject:** 2003 RRR Review

Walter,

The material we discussed with John Bell and Frank this morning is attached.



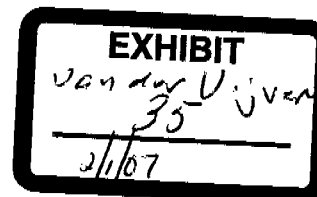
2003 Reserves  
20031114.ZIP

**John Pay**  
Group Hydrocarbon Resource Coordinator  
Shell International Exploration and Production B.V.  
Shell Exploration & Production International Centre  
Kessler Park 1, 2288 GS,  
PO Box 60, 2280 AB,  
RIJSWIJK-ZH,  
The Netherlands

**Tel:** +31 (70) 447 2547 **Other Tel:** +31 (0)6 5252 1964  
**Email:** john.pay@shell.com  
**Internet:** <http://www.shell.com/eandp-en>

Incoming mail is certified Virus Free.

1



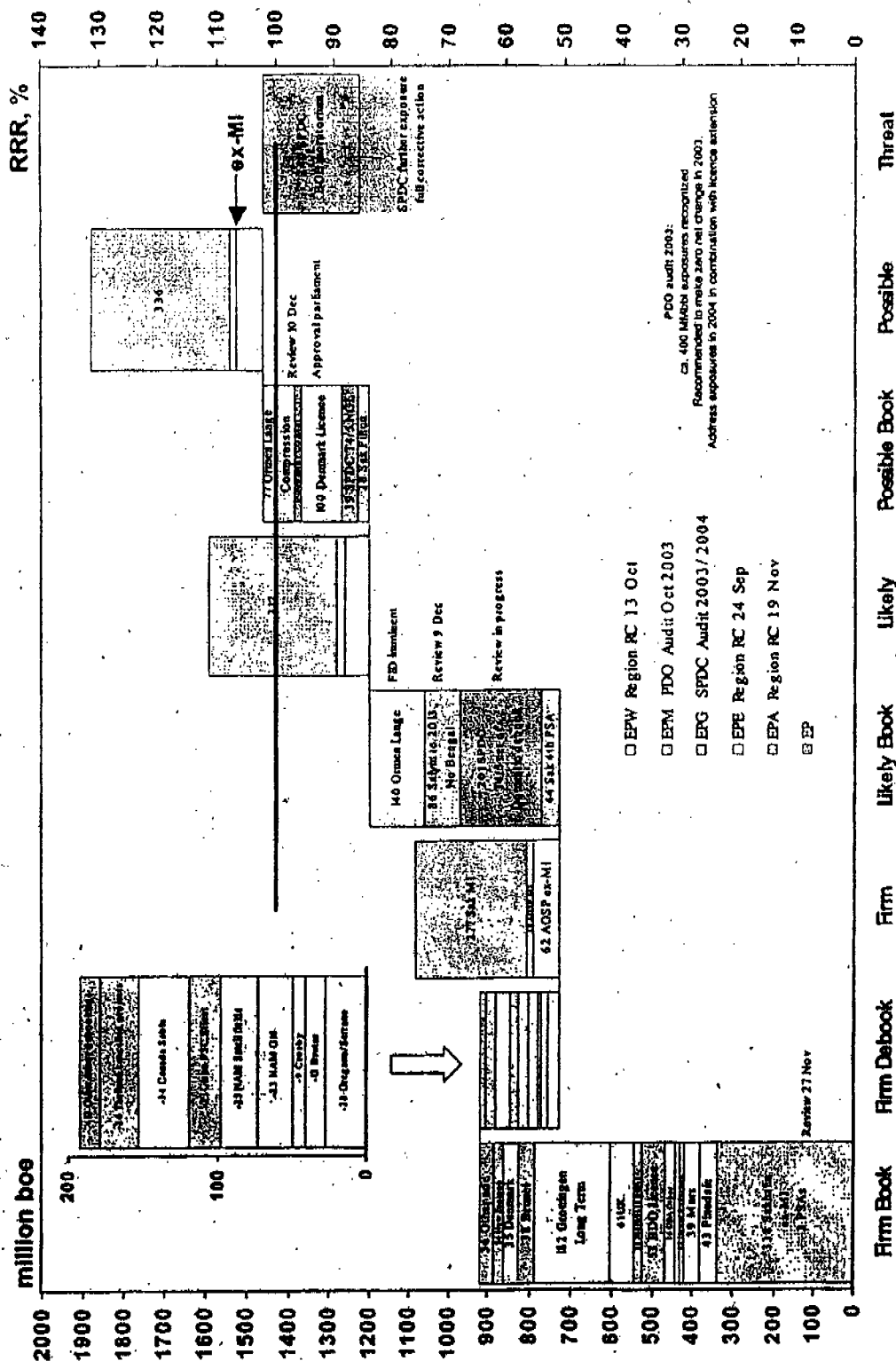
NOIA CONFIDENTIAL  
TREATMENT REQUESTED

V00010813

Checked by AVG anti-virus system (<http://www.grisoft.com>).  
Version: 6.0.567 / Virus Database: 358 - Release Date: 24/01/2004

# 2003 Organic Proved Reserves Additions

Confidential



EPS

2003 Proved RRR Review 14 Nov 2003

2003 Reserves 20031114.ppt

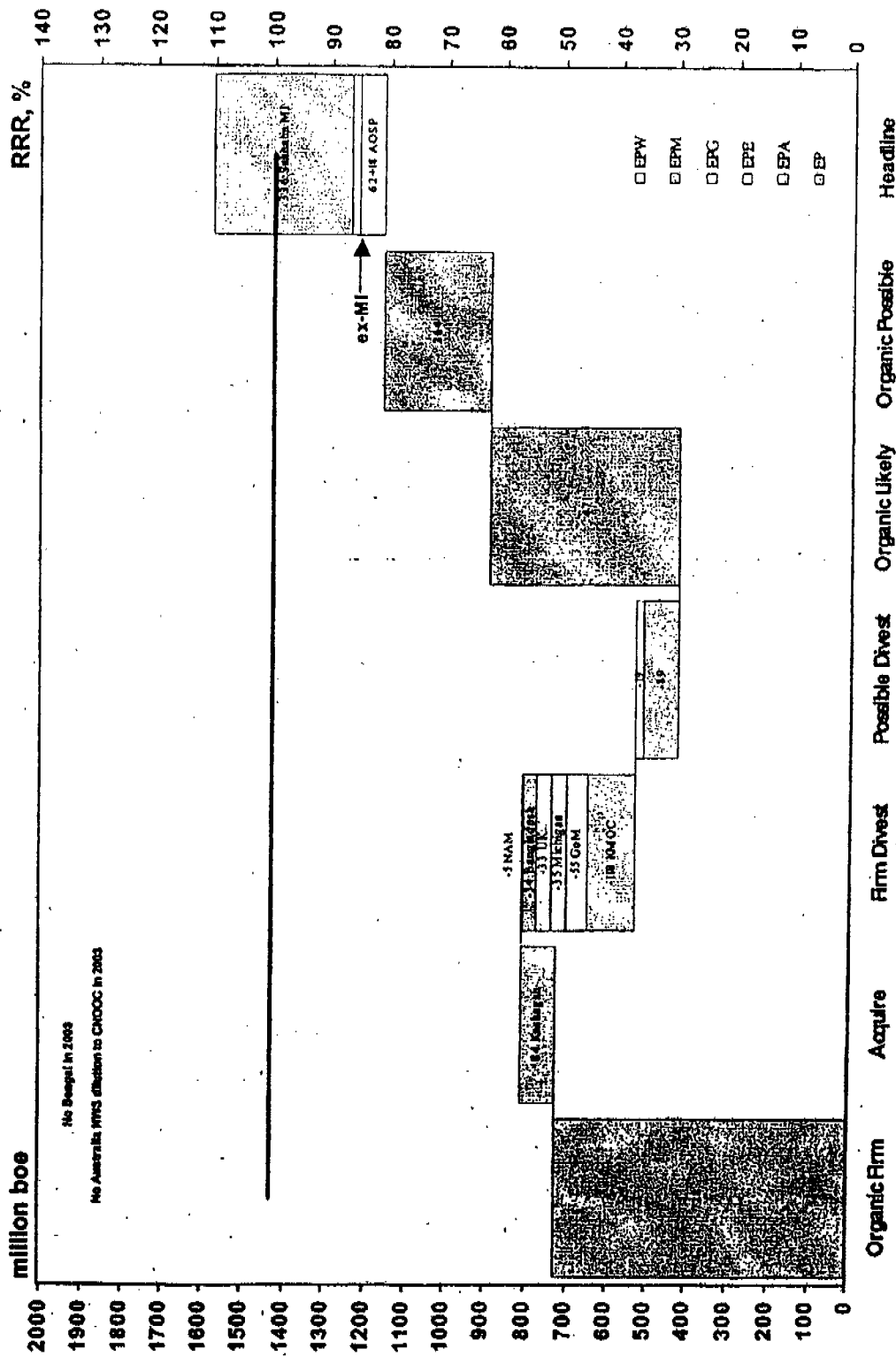
FOIA CONFIDENTIAL  
TREATMENT REQUESTED

V00010815



# 2003 Total Proved Reserves Additions

Confidential



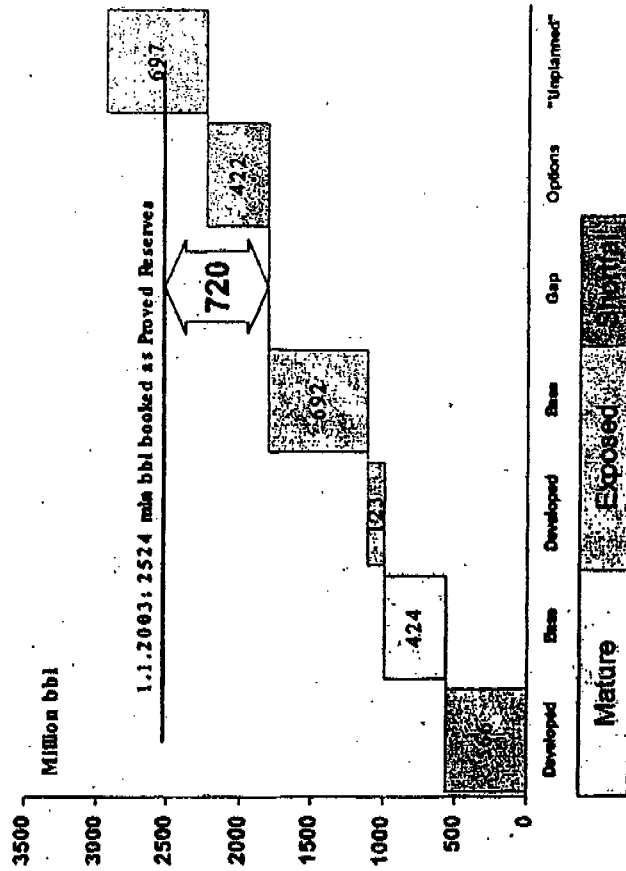
EPS

2003 Proved RRR Review 14 Nov 2003

2003 Reserves 20031114.ppt

## SPDC Oil

Confidential



	Developed	Base	Options	Unplanned
Alakiri	2	2	41	0
Belama	37	9	0	10
Bizeni	0	16	0	0
Bonny	4	23	0	0
Cawthorne Channel	97	126	0	1
EA	0	157	13	0
Forcados-Yokri	52	125	0	4
Gbaras/Ubie	48	81	27	3
Jons Creek	24	23	10	5
Kalashule	8	0	29	0
Nun River	22	4	50	0
Oben	4	0	0	39
Obolo	68	70	39	37
Odidi	39	36	27	34
Oguta	10	14	66	0
Otuomara	26	1	49	41
Sapele	12	32	0	25
Soku	117	182	9	125
South Forcados	50	110	0	51
Ughelli	66	81	48	235
Warri	0	0	0	14
Unallocated	0	14	14	54
Total	688	1116	422	897
				1119*

\* Doesn't (yet) include H-Block and Ulapate

Excludes any contribution from the CIW project.

Base + Developed 1804  
 Currently booked oil 2524  
 Gap 720

• Gap between Business Plan portfolio and SEC Proved Reserves: 720 million bbl

- Portfolio of ca. 1100 million bbl with which gap could be closed over time
  - Mix of small and major projects: 'small' insufficient to bridge gap
  - All long-term, post-plan period, immature
  - Acceleration cannot be accommodated within plan Capex ceiling
- May require carrying known exposure vs. FID criterion for several years

EPS

2003 Proved RRR Review 14 Nov 2003

2003 Reserves 20031114.ppt

Darley, John J SIEP-EPT

From: Coopman, Frank F SIEP-EPF  
Sent: 02 December 2003 07:54  
To: Bell, John J SIEP-EPS; Bichsel, Matthias M SIEP-EPX; Darley, John J SIEP-EPT  
Cc: Pay, John JR SIEP-EPS-P  
Subject: proved reserves

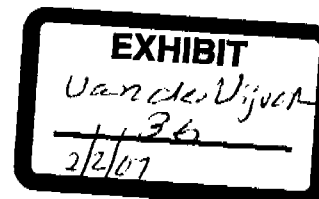
Please find attached our draft note which is now with Walter. No comments as yet.  
My functional boss is not happy.



Script for Walter on  
the prove...

Frank Coopman  
Chief Financial Officer for EP  
Shell International Exploration and Production B.V.  
PO Box 60, 2280 AB Rijswijk ZH, The Netherlands

Tel: +31 70 447 4303 Fax: +31 70 447 5959  
Email: Frank.Coopman@shell.com  
Internet: <http://www.shell.com/eandp-en>



FOIA Confidential  
Treatment Requested  
RJW00780060

Script for Walter on the proved reserves position

Facts

1. Recent (October–November) audit reports and completion of reserves studies concerning the proved reserves positions as per year end 2002 for SPDC and PDO Oman tell us that the 31/12/02 proved reserves for those companies were overstated by approximately 1.3 bln boe.
2. Correspondence with the SEC in 2003 (last letter received in September) on the topic of the LKH issue leaves us with the message from the SEC to de-book the volumes below the Lowest Known Hydrocarbon logged. These volumes are estimated to be approximately 300 mln boe.
3. The proved reserves bookings as filed in the 2002 20F included a number of items which, while in compliance with our own guidelines at that time, were possibly at odds with the strictest possible interpretation of the SEC guidelines. It was decided to leave them as, in aggregate, they were regarded as immaterial in relation to our total proved reserves position. The largest single position was Gorgon (557 mln boe). All others added up to less than 200 mln boe.

Consistency with previous presentations

The position described above is consistent with an October presentation to the GAC and a related NFI to CMD. What is new are the items under point 1 above, which became known only very recently.

Materiality

With the SPDC and PDO Oman volumes, the total volume not in compliance with SEC guidelines in the proved reserves filing in the 20F as per 31/12/02 has become significant (2.1 bln boe or 11% of the Group's total proved reserves).

The materiality test is whether the total change in reported reserves would be viewed by a reasonable investor as having significantly altered the total investment information available. Applying that parameter, the absolute quantity and the percentage is material.

If a de-booking or restatement was considered, the financial impact thereof is very limited (approximately 40 mln dollars after tax in 2003) and not material in Group (or EP) terms. This is because virtually all volumes to be adjusted are registered as proved undeveloped reserves – this category only rarely drives DD&A.

There is no effect on existing or past reserve addition bonus schemes (in Oman and Nigeria).

FOIA Confidential  
Treatment Requested  
RJW00780081

### Completeness

If we were to de-book /restate points 1 - 3 above, would we then be in full compliance with the SEC guidelines?

There is a possible issue around our Kashagan reserves (380 mln boe). Total is being challenged right now by the SEC to de-book on the grounds of the absence of a government approved development plan.

Both PDO Oman and SPDC will have to further mature field development plans in 2004 to be fully compliant and avoid further adjustments.

### Fuel and Flare

All major competitors include fuel and incidental flare in proved gas reserves, with the exception of BP who report on the same "as sold" basis as Shell.

Including fuel and flare would result in approximately 300 mln boe additional reserves as reported at 31.12.2002. However, implementation is not as straightforward as it would at first appear. Inclusion of fuel and flare requires a corresponding Opex charge to be made (at fair market value of the gas consumed), offset by a revenue entry. Consequently, including fuel and flare in any restatement of historically disclosed reserves would also require changes to several financial report line items. Whilst feasible, this would be a major undertaking requiring dedicated study work on the part of every operating company that disclosed production in recent years.

Therefore, it is recommended not to include fuel and flare in the restatement.

### Legal Consequences and Required Steps

If and from the time onwards that it is accepted or acknowledged by the management of the issuers (Royal Dutch and STT) that, when applying the SEC rules, the 2002 proved reserves as reported in the Form 20-F are materially wrong, the issuers are under a legal obligation to disclose that information to all investors at the same time and without delay. Not to disclose it would constitute a violation of US securities law and the multiple listing requirements. It would also increase any potential exposure to liability within and outside the US. Note that the reserves information also appears in the non 20-F Annual Reports.

Disclosure cannot await the next Form 20-F 2003 appearing in April 2004. With respect to the 2002 Form 20-F there are two possible approaches to address the previously reported reserves: (i) a stock exchange release stating the key issues on reserves restatement followed by a filing of a restated 2002 Form 20-F as soon as possible thereafter or (ii) the same stock exchange release with the added message that the changes will be reflected in the 2003 Form 20-F and no filing of a restated 2002 Form 20-F. The preference is for the more robust approach in i) as the SEC is likely to request for a restated 2002 Form 20-F and the reliance by investors on an uncorrected 2002 Form 20-F remains an issue.

FOIA Confidential  
Treatment Requested  
RJW00780062



A significant number of additional measures will be required around a restatement of the 2002 Form 20-F and the previous dissemination of incorrect proved reserves data on Group websites and in other publications. Sox 302 re-certification, Form 6 K filing, consultation with external auditors, communication with the SEC, briefing for analysts etc.

IR issues

The announcement of restating or de-booking the reserves will be a significant negative IR event. We will point out that we did not lose any significant hydrocarbon volumes, as this is basically a re-classification. Our expectation estimate of the total volume of resources will be largely unaffected. Our own strict rules and governance triggered this adjustment. The LKH issue remains controversial in the industry (but rules are rules, etc). The Gorgon development decision is getting closer, as the recent bi-lateral declaration of intent demonstrated.

Frank Coopman  
John Pay

1 December 2003

FOIA Confidential  
Treatment Requested  
RJW00780063

Van De Vijver, Walter SI-MGDWV

---

From: Van De Vijver, Walter SI-MGDWV  
Sent: 02 December 2003 09:57  
To: Boynton, Judith G SI-MGDJB  
Cc: Van der Laan, Marian M SI-MGDWV/DIRMB  
Subject: RE: Reserves

Judith,

I will investigate. Indeed this whole issue is extremely serious and I had concluded from my numerous discussions with Frank (and your separate discussions) that Frank knew he was expected to do the staffwork and create options, ie not to come with a firm recommendation. Indeed the full consultation needs to happen with all key stakeholders and I was assured by Frank that he knew what was expected from him.  
Earliest I can probably work this is early tomorrow morning.

Regards  
Walter

-----Original Message-----

From: Boynton, Judith G SI-MGDJB  
Sent: 02 December 2003 07:55  
To: Van De Vijver, Walter SI-MGDWV  
Subject: Reserves

Walter—I have been trying to reach you but I understand that you have been busy with our ongoing deal. Just to let you know that Frank sent me today a copy of a script he has sent you regarding reserves. Neither the Group Controller nor I were consulted about the script before it was written or sent. Frank was out of bounds in documenting views without full consultation. This is a very serious matter and I would appreciate talking about it at your earliest convenience. I am in the Hague today X4151. Thanks, Judy

Judith G. Boynton  
Group Managing Director and Chief Financial Officer  
Royal Dutch/Shell Group of Companies  
Shell Centre, London SE1 7NA  
Tel: +44 (0)207 934 3003 Fax: +44 (0)207 934 7132  
Internet Address: judith.boynton@shell.com



FOIA CONFIDENTIAL  
TREATMENT REQUESTED

V00010837

Van De Vijver, Walter SI-MGDWV

---

From: Van De Vijver, Walter SI-MGDWV  
Sent: 02 December 2003 09:52  
To: Coopman, Frank F SIEP-EPF  
Subject: RE: reserves

This is absolute dynamite, not at all what I expected and needs to be destroyed!

We are only at this stage flagging issues and creating options, not making a firm recommendation. You well know that I have not accepted the latest audit reports and need far more answers before coming to a recommendation (given the Group impact this needs formal sign-off by CMD, GAC, etc). I have been absolute clear on this at numerous occasions.

Regards,  
Walter

-----Original Message-----

From: Coopman, Frank F SIEP-EPF  
Sent: 02 December 2003 07:12  
To: Van De Vijver, Walter SI-MGDWV  
Cc: Rose, Jennie SI-MGDWV  
Subject: reserves

<< File: Script for Walter on the proved reserves position.doc (Compressed) >>

Frank Coopman  
Chief Financial Officer for EP  
Shell International Exploration and Production B.V.  
PO Box 60, 2280 AB Rijswijk ZH, The Netherlands

Tel: +31 70 447 4303 Fax: +31 70 447 5959  
Email: Frank.Coopman@shell.com  
Internet: <http://www.shell.com/eandp-en>

FOIA CONFIDENTIAL  
TREATMENT REQUESTED



V00010836

**Unknown**

From: Van De Vijver, Walter SI-MGDWV  
 Sent: 08 December 2003 00:05  
 To: Pay, John JR SIEP-EPS-P  
 Cc: Coopman, Frank F SIEP-EPP; Darley, John J SIEP-EPT; Bell, John J SIEP-EPS  
 Subject: RE: Proved Reserves Part 1: DRAFT FOR COMMENT

John,

Many thanks.  
 My comments on the note:

- I would include the internal/external timeline in the summary. Wrt the table it should flag all large bookings and be checked (later in the text it talks about 660 MMboe for SPDC!). The summary should also clarify the large change in 96 which led to > 200 % RRR. This also applies to the chronological summary on page 9! I like to see impact to expectation reserves in summary also (earlier we stated that expectation reserves would be largely unaffected!)

I still feel uncomfortable with the "increased tightening of the SEC guidelines" as if the SEC is the reason we have a problem today! The reality appears to be with us driving for aggressive reserves bookings as far as we could stretch the SEC rules! I want this re-worded! It should also be made clear that as of late 2001 there was a real drive to top-down improve integrity of our reserves base, earlier attempts to do so since 2000 were left to lower authority levels whilst pushing for max. RRR.

Was the FRD now initiated in 1997 or 1998, conflicting references!

- why can't we be more clear about why the bookings happened when they happened as we have done before by breaking it into categories such as known aggressive bookings, new SEC interpretation and new operational learning? Suggest the text on page 20 and 22 looks too much like trying to find the PLE's! I also consider that the text on page 37 could be improved by bringing in the clarity what these license extension would actually deliver (automatic right in SPDC ie what would otherwise exposure be? and currently ongoing negotiations in Oman).

Can we move the figure on page 21 into the summary as well? I would guess that only LKH's and PSC's would fall under new SEC interpretation

and that perhaps 300 MMboe would fall under new operational learning (mainly Oman)?!

When looking at SPDC and PDO is it really valid to portray that we only recently (top page 23) discovered the problem in Oman and Nigeria?

I think we knew much earlier and this was reflected in formal assurance letters/audit reports?!

- I personally find the coding under competitor compliance very confusing (page 16/17), suggest to simplify it without codes!

- Have we fully worked the new bookings in case of de-bookings in Oman and Nigeria? I was hoping for larger volumes with the

new waterfloods going for VAR 4 in 2004/05 in Oman and the various T4/5/6 projects in Nigeria? GOing above 100 % RRR

in 2004 would be a big prize!

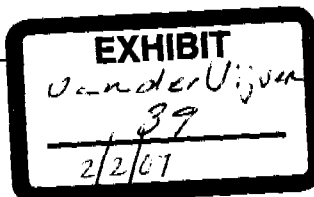
- Assume all PD de-bookings are related to Nigeria, please confirm. The earlier attachments have disappeared!

(please re-check my questions from this morning, do not think all are addressed)

Separately we still need to decide as EP where we want to go with this based on the various analyses:

- do you have a recommendation on size of de-bookings and how will we do it, also thinking reputation/IR?
- assume for CMD we also have all data on reserves bonuses in Oman and Nigeria on achieved track record and potential exposure
- assume for CMD we have the impact on financials and SM data reported
- do we have a storyline that is close to "merely reclassification" of proved reserves as it mainly affects proved developed?

FOIA CONFIDENTIAL  
 TREATMENT REQUESTED



V00010881

Suggest that we discuss this early in the morning as I do want to get this issued by noon latest today!  
Thanks,

Walter

-----Original Message-----

**From:** Pay, John JR SIEP-EPS-P  
**Sent:** 07 December 2003 22:15  
**To:** Van De Vijver, Walter SI-MGDWV; Boynton, Judith G SI-MGDJB; Morrison, Tim TDR SI-FC  
**Cc:** Coopman, Frank F SIEP-EPP; Darley, John J SIEP-EPT; Bell, John J SIEP-EPS  
**Subject:** RE: Proved Reserves Part 1: DRAFT FOR COMMENT

... and "Jim" Morrison - feeling bad, no need to say any more

<< File: Proved Reserves Dec 2003 Part 1 v06.doc (Compressed) >>

**John Pay**  
Group Hydrocarbon Resource Coordinator  
Shell International Exploration and Production B.V.  
Shell Exploration & Production International Centre  
Kessler Park 1, 2288 GS,  
PO Box 60, 2280 AB,  
RIJSWIJK-ZH,  
The Netherlands

**Tel:** +31 (70) 447 2547 **Other Tel:** +31 (0)6 5252 1964

**Email:** john.pay@shell.com

**Internet:** http://www.shell.com/eandp-en

-----Original Message-----

**From:** Pay, John JR SIEP-EPS-P  
**Sent:** 07 December 2003 20:46  
**To:** Pay, John JR SIEP-EPS-P; Van De Vijver, Walter SI-MGDWV; Boynton, Judith G SI-MGDJB; Morrison, Jim R SITI-ITDPET  
**Cc:** Coopman, Frank F SIEP-EPP; Darley, John J SIEP-EPT; Bell, John J SIEP-EPS  
**Subject:** RE: Proved Reserves Part 1: DRAFT FOR COMMENT

Recall initiated on version sent in error to the wrong John Bell, plus message from John Darley instructing the recipient to delete.

<< File: Proved Reserves Dec 2003 Part 1 v06.doc (Compressed) >>

**John Pay**  
Group Hydrocarbon Resource Coordinator  
Shell International Exploration and Production B.V.  
Shell Exploration & Production International Centre  
Kessler Park 1, 2288 GS,  
PO Box 60, 2280 AB,  
RIJSWIJK-ZH,  
The Netherlands

**Tel:** +31 (70) 447 2547 **Other Tel:** +31 (0)6 5252 1964

**Email:** john.pay@shell.com

**Internet:** http://www.shell.com/eandp-en

-----Original Message-----

**From:** Pay, John JR SIEP-EPS-P  
**Sent:** 07 December 2003 19:35  
**To:** Van De Vijver, Walter SI-MGDWV; Boynton, Judith G SI-MGDJB; Morrison, Jim R SITI-ITDPET  
**Cc:** Coopman, Frank F SIEP-EPP; Darley, John J SIEP-EPT; Bell, John J SI-ITCG  
**Subject:** Proved Reserves Part 1: DRAFT FOR COMMENT

Please find attached a draft of the proposed CMD paper for comment.

I will bring a paper copy to Judy at the Kurhaus at approximately 21:00, but I will not leave it unless it can be



delivered by hand.

<< File: Proved Reserves Dec 2003 Part 1 v06.doc (Compressed) >>

**John Pay**

Group Hydrocarbon Resource Coordinator  
Shell International Exploration and Production B.V.  
Shell Exploration & Production International Centre  
Kessler Park 1, 2288 GS,  
PO Box 60, 2280 AB,  
RIJSWIJK-ZH,  
The Netherlands

Tel: +31 (70) 447 2547 Other Tel: +31 (0)6 5252 1964

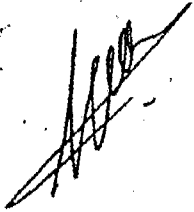
Email: [john.pay@shell.com](mailto:john.pay@shell.com)

Internet: <http://www.shell.com/eandp-en>

FOIA CONFIDENTIAL  
TREATMENT REQUESTED

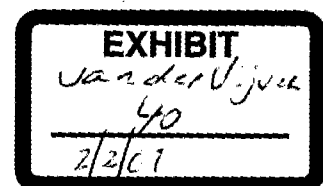
Note to CMD  
Oil and Gas Reserves  
Proved Reserves

The attached note provides an overview of the current situation and recent changes with respect to estimates of proved oil and gas reserves, as disclosed in the Supplementary Information to the Group Financial Statements. The note is submitted in preparation for tomorrow's review. The summary of 5 pages provides the technical perspective on the most relevant developments. Further refinements are ongoing to double-check the numbers and to finalise the very recent work in Oman and Nigeria.



MGDWV  
8<sup>th</sup> December 2003

FOIA CONFIDENTIAL  
TREATMENT REQUESTED



V00010442

8 December 2003

Confidential

## Note to CMD

### Proved Reserves

#### 1. Summary

A combination of recent audit report findings and the gradual application of tighter internal EP guidelines reflecting stricter interpretation of the SEC rules on reserves bookings suggests that EP is overstating proved reserve volumes in the SEC filing (20-F) by some 2.1 to 3.6 bln boe. This would clearly represent a material change to the Group's proved reserves position as at end 2002 (19.3 bln boe). The SEC rules and guidance are open to some degree of interpretation. This note examines the facts and circumstances of the current reserves situation.

#### *Background*

Proved oil and gas reserve volumes are filed as Supplementary Information in the Annual Report on Form 20-F with the SEC. In addition, they are published in the 5 year Financial and Operational Information and in summary form in the Annual reports of RD and ST&T.

The official text of the guidelines governing the public disclosure of oil and gas reserves was published by the SEC in 1978. These guidelines ("borrowed from FASB and the DOE") remain unchanged. The criteria relate to the technical and commercial conditions under which oil and gas reserves can be considered proved. The first extensive, written, public guidance on technical interpretation of the formal rules was published on the SEC website in March 2001. The interpretation provided additional definition on the technical and commercial compliance requirements governing proved reserves, including the acceptable extent of a proved accumulation and evidence of commitment to develop the reserves. Subsequent communication with officers of the SEC has confirmed their increasingly rigorous interpretation of the official text, which they see as being necessary for compliance with proved reserves definitions.

The approach to proved reserves reporting in the Group followed two distinct paths, which have merged into a single approach following the integration with Shell Oil. Historically, as a US-based company filing reports with the SEC (and DOE), SOC (now SEPCo) closely followed the SEC reserves rules, including strict investment criteria on reserves bookings (e.g. FID required prior to reserves booking for major projects). Through the 1980s and first half of the 90s, the Shell International approach applied and further defined a rigorous methodology for the technical interpretation of hydrocarbon reserves.

Probabilistic modelling techniques were used and proved reserves were defined at the low end of the uncertainty range. Technical maturity and commercial viability were introduced as key criteria, but less consideration was given to investment

EPS, EPF, EPT

1

Proved Reserves Dec 2003 Part 1 CMD.doc

8 December 2003

Confidential

commitments. According to the prevailing Shell guidelines, proved reserves could be booked before project approval was sought.

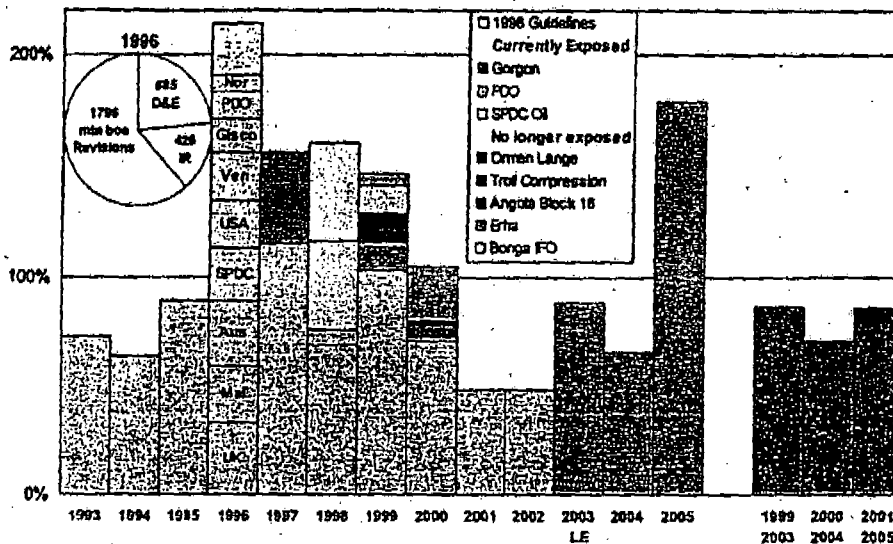
Another important difference in the Shell Group approach is the recognition, and application, of a range of reserve values in business planning. While the proved volumes are reported as part of the annual disclosure exercise, internal business plans are generally based on the "expectation", or mid-range value of the reserves uncertainty curve. (This is sometimes equated to proved plus probable reserves in the industry). An upside, or high-end value (proved plus probable plus possible) is also used to appreciate possible upside potential in the development options. Shell uses the term "Scope For Recovery" to describe hydrocarbon volumes associated with projects that are not yet sufficiently mature to be classified as "reserves". The SEC approach recognizes only proved reserves (and actually prohibits the publication of all non-proved categories in Form 20-F).

Following a period of low levels of reserve replenishment in the first half of the 1990's, concerns were voiced that the Shell approach to proved reserves definition was overly conservative. A stronger drive to identify and book proved reserves was then promoted across the EP business, resulting in 1996 in substantial additions driving RRR over 200%, mainly through revisions but also with new business (Venezuela, Gisco). In 1997-1998, a LEAP Value Creation Team assessed the opportunities to "Create Value through Entrepreneurial Management of Hydrocarbon Resource Volumes". Drivers for change included an appreciation of inherent conservatism (e.g. by comparison with proved reserves booking of JV partners in certain shared ventures) and a need to complement technical strength with a focus on value. Recommendations included changes to the Petroleum Resource Volume Guidelines, plus a number of initiatives to boost entrepreneurship, knowledge sharing, risk management, etc. In fact some 1000 mln boe were actually booked as 'revisions' in the period 1998 to 2000, most notably in Nigeria (1998) and Oman (2000). This is illustrated below:

8 December 2003

Confidential

## Proved RRR: Organic (excl A&amp;D), excl. the effect of Sakhalin MI, Incl. AOSP



Since late 2000, and following moves to integrate the Shell Oil and SIEP guidelines, Group technical and commercial requirements for the disclosure of proved reserves have gradually tightened. The October 2003 SIEP guideline (presented to the GAC) requires FID for the booking of reserves from a major project and VAR3 compliance (i.e. approved development concept selection) for intermediate sized projects. This is in contrast to, for example, the 1998 guideline, which specified that while there should be a reasonable expectation that a firm development plan could be matured with time, projects did not require a completed development plan to meet the proved criteria.

In parallel with the tightening of the guidelines, measures have also been taken since late 2001 to improve the technical and professional standards which underpin hydrocarbon field development planning -- and hence reserve estimates. Initiatives to raise performance at an EP level (formation of the Technical and Operational Excellence unit in 2002, roll-out of a competency framework for technical professionals, plus other measures) have been complemented by specific SIEP reviews in Oman (2002 -- 2003) and Nigeria (most recently 2003) to address questions around the confidence of reserve estimates and the corresponding development plans. The reviews have confirmed the requirement to radically improve field development planning capability, and that, in some cases, hydrocarbon reserve estimates were insufficiently under-pinned with comprehensive study work.

Further to the above initiatives, recent audits by the Group Reserves Auditor have revealed poor compliance in SPDC and PDO with the recent SEC criteria, and with the updated Group Guidelines. The technical maturity required to underpin these volumes is indeed questionable due to lack of focus on medium

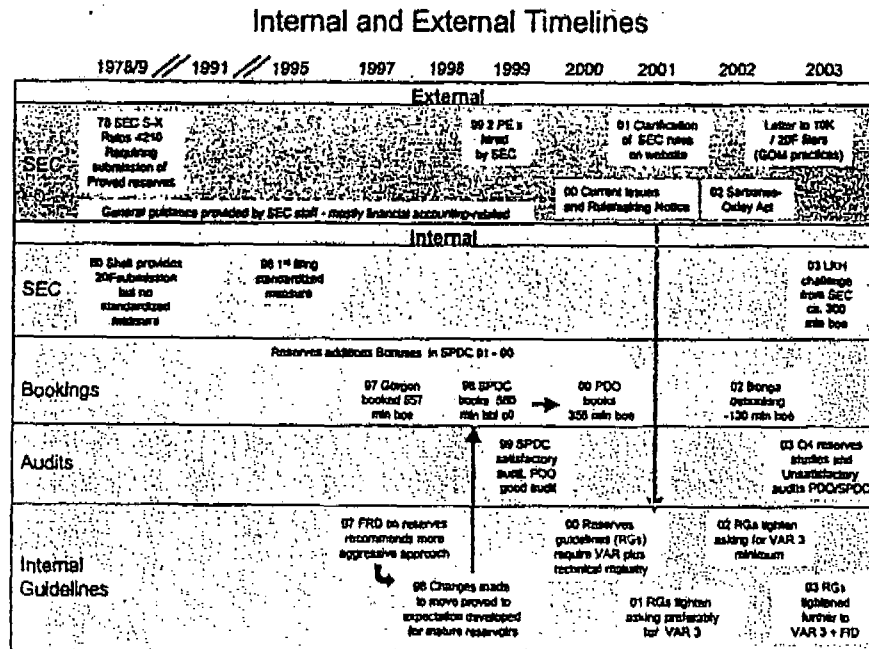


8 December 2003

Confidential

to longer-term project definition. The most significant impact is generally felt on the proved undeveloped reserves volumes, where both technical and commercial maturity are sometimes poorly defined.

The evolution of the changes is captured in the following chart, together with some of the main impacts on booked volumes of proved reserves:



The consequences of these audit observations and the recent changes to the Shell guidelines (which are seen to bring the Group in line with SEC definitions), is that significant volumes of proved reserves, which were booked under existing Shell guidelines, are no longer compliant with current Shell guidelines. These volumes therefore are not likely to be interpreted by the SEC as compliant.

The realization of this impact has prompted a wider-ranging review of proved reserves compliance with SEC guidelines, with the current situation summarized below. The split between the two categories in the table is indicative only at this stage:

8 December 2003

Confidential

*Proved reserves which are likely to be considered as not compliant by the SEC*

Country	Field	Non-compliant reserves as at 31.12.2002 (est. mln boe)		Reason
		Proved	Expectation	
Australia	Gorgon	557	785	No FID or investment commitments
Nigeria	Onshore (SPDC)	720	ca. 1400	No mature plans / projects
Oman	Existing fields	234	240	Immature projects, (some) unproved techniques
LKH	Various	ca. 300	0	New SEC guidance
PSCs	Various	291	0	Oil / gas price assumption in calculation of reserves entitlement
<b>TOTAL</b>		<b>2102</b>	<b>2430</b>	

*Proved reserves which might be considered as not compliant by the SEC*

Country	Field	Potentially non-compliant reserves (est. mln boe)		Reason
		Proved	Expectation	
Nigeria	Onshore (SPDC)	814	ca 1600	Plans/projects in progress (but not VAR3-compliant)
Oman	Existing fields	150	0	To be firmed up in short-term (2 years)
Kazakhstan	Kashagan	380	500	Government may not approve plan. Technical definition of proved area.
Others	e.g. Corrib, Tempa Rossa	ca. 200	270	No approved plan
<b>TOTAL</b>		<b>1544</b>	<b>2370</b>	

The reserves identified as likely to be not compliant with SEC guidelines represent 11% of the Group proved reserves (excluding oil sands), while the potentially non-compliant volumes would raise this to 19%. The corresponding figures for expectation reserves would be 7% and 15% respectively.

EP is currently in a stage of transition to the adoption of the new guidelines. Booking of new reserves must follow the clear guidelines on VAR3 and FID criteria, and careful audit and control will need to be exercised to ensure this. However, it may be expected that a period of time is needed before all existing booked proved reserves are fully compliant with the new requirements. At the same time, the criteria for retention of reserves as proved volumes require a clear indication of demonstrable progress to technical and commercial maturity.

It should be noted that most volumes debooked at this time would be expected, over time (but in most cases, the long-term), to become fully compliant and bookable again.

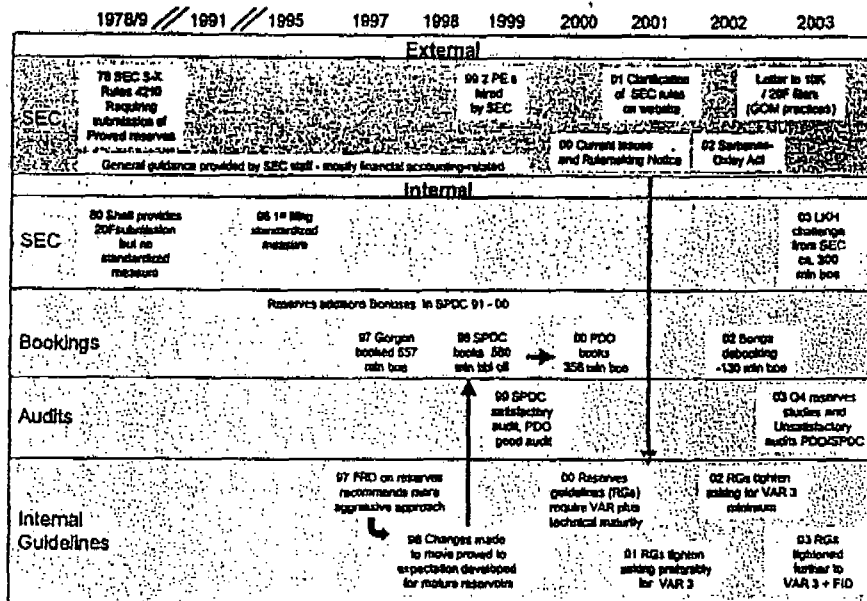
8 December 2003

Confidential

## 2. History of Shell Internal Guidelines Development

The following diagram is intended to provide an overview of the various significant events and developments that have occurred over time, that have influenced the Group's interpretation of its external reserves disclosure requirements. The detail is explained in section 2.1 to 2.4 below:

Internal and External Timelines



### 2.1 Developments in SEC Rules and Guidance

1978: the US Financial Accounting Standards Board (FASB) issued definitions of proved reserves and related terms (FAS25). The US Securities and Exchange Commission (SEC) adopted these definitions in the same year, (eventually) incorporating them into Regulation S-X and advising the industry of the requirements for disclosure through Accounting Series Release number 257 (ASR-257).

The SEC / FASB definitions and "rules", as embodied in Regulation S-X and FAS19, FAS25 and FAS69, have *not* changed. What *has* changed is that, since 1999, the SEC has become progressively more vocal on the matter. In so doing, it has issued guidance on the manner in which it expects proved reserves to be estimated that imply a far greater degree of rigour and conservatism than typically has been applied in the past, certainly by the Group (and probably non-US-based registrants) outside the US.

8 December 2003

Confidential

1982 – 1989: Staff Accounting Bulletins on “Topic 12” issued. These are presented by the SEC as representing “... *interpretations and practices followed by the SEC’s Division of Corporate Finance and the Office of the Chief Accountant in administering the disclosure requirements of the Federal securities laws.*” The focus was generally on financial accounting issues.

Until early 1990s: “*Most of the SEC technical enforcement during late seventies through early nineties was directed to reviews of Initial Public Offerings (IPOs).*”<sup>IV 1</sup>

1998 – present day: “[There was] *No petroleum engineer on SEC staff from [the] early nineties until a brief period in 1998. Two engineers ... [were] hired in early 1999.*”<sup>IV 1</sup>

From 1999, guidance on “technical” (i.e. other than financial accounting) issues increased via:

- Society of Petroleum Evaluation Engineer (SPEE) “Forums for US SEC Reserve Definitions”, held annually since October 2000:
  - SEC Petroleum Engineers meet with industry representatives for unofficial mutual learning discussions.
- SEC website publication of March 31, 2001 including “Definition of Proved Reserves”
  - Prepared by SEC Petroleum Engineers. It provided the first written, public guidance (beyond SEC Regulation S-X) on technical topics such as: data needed to support reserve estimates; treatment of reserves from uneconomic production; conclusive formation test; Lowest Known Hydrocarbon (LKH); improved recovery reserves; economic uncertainties; need for markets; commitment to develop; continuity of production; use of numerical reservoir simulation; probabilistic estimation methods (not favoured); determining reserves in Production Sharing Contracts (PSCs); civil liability of individuals involved in reserve estimation and reporting.

#### 2002: Sarbanes-Oxley Act

October 2002 – present: The SEC engaged in correspondence with many registrants (primarily operators of US Gulf of Mexico (GoM) assets), including Shell, requesting information about proved reserves reporting practices.

2003: A noticeable change (hardening) occurred in the SEC staff position on some reserves issues. For example, “... *in May of 2003, they [SEC Petroleum Engineers] recanted their position adopted in 2000 whereby they agreed to use certain technical information in the estimation of reservoir [hydrocarbon-water] contacts where such data could be used as the basis of a “compelling case”. Their “new” position is [that] only well bore*

<sup>1</sup> In this section 2.1, quotations marked “TV” (“Independent View”) are attributed to a respected, independent technical consultant, based in the US and well versed in both the SEC rules on proved reserves and their practical implementation. Generally they are drawn from private but professional correspondence with Shell staff.

8 December 2003

Confidential

*data, primarily well logs, can form the basis of lowest known hydrocarbons. This position completely ignores information available through seismic, through multiple formation pressure [measurements] and fluid sample and core data."* <sup>IV</sup>

Overall, the clear focus of the SEC technical staff is to protect the (potential) investor from exposure to unfair risk that might arise from registrants misrepresenting proved reserves and the value thereof. In so doing, they appear to act so as to promote a dictionary definition of the term "proved" and take exception to any element of proved reserves that might be termed "aspirational" in nature. They fully recognize that registrants plan and execute their businesses based on an expectation view of the production to be delivered from their assets, but they are clear that this is quite different to the intended meaning and interpretation of the SEC and FASB definitions. The SEC staff has expressed surprise (verbally) that the industry has not lobbied for the disclosure of probable reserves, in addition to proved reserves (apparently this was discouraged by ExxonMobil during consultation due to fears of an increased audit burden).<sup>2</sup>

Under disclosure rules recently introduced by the Canadian authorities, registrants there are required to report both proved and probable reserves, together with any other resource categories that they wish to bring to the investor's attention.

The Society of Petroleum Engineers (SPE) has recently offered to act as an independent technical consultant to the SEC on matters relating to reserves estimation. The SEC's response is awaited.

---

<sup>2</sup> The industry has complained that the disclosure of proved reserves alone, i.e. to the exclusion of all other resource categories, provides the investor with little insight to the true value of an enterprise. In issuing FAS69, the FASB recognized this. Whilst the aspiration was for a declaration of Fair Market Value, the board concluded that this would be impracticable for reasons that included the confidentiality of much of the information that would be required for disclosure. In settling on proved reserves, the board was satisfied that the approach would approximate Fair Market Value, without actually achieving it.



8 December 2003

Confidential

## 2.2 Group Outside US

**Early 1970s:** The Group's use of probabilistic reserves estimation techniques for internal reporting and management purposes was established. No external disclosures were required at this stage.

**1979:** In considering how to implement ASR-257, the Group determined that *'For the purpose of reporting proved reserves for the SEC the 85 per cent confidence level is considered 'reasonably certain' within the context of the SEC requirements and should be used as such.'* This view, no challenge of which can be found on record, became the standard by which the Group disclosed proved reserves for the next 20 years. Contrary to widely held belief, both within Shell and outside (e.g. ExxonMobil), the Group appears neither to have sought nor received confirmation from the SEC that this interpretation was acceptable.

Similarly, since ASR-257 mentioned the requirement to disclose proved reserves in one breath and production on an "as sold" basis in the next, it was taken as read that both production and reserves must be expressed on an "as sold" basis (i.e. excluding gas volumes consumed as fuel or flared). This policy was adopted apparently without serious challenge and remains in force today, although it is now clear that the SEC allows (even expects) reserves to be disclosed on a "wellhead production" basis when the gas could otherwise have commercial value. Shell and BP are the only majors that report on a "production available for sale" basis.

**1982 - 1995:** Despite being a clear FAS69 disclosure requirement, the Group declined to file reports of the Standardized Measure of Discounted Cash Flow (effectively, the Net Present Value of the company's proved reserves). This information was included with effect from 1996 as a precautionary measure, to protect against possible complications in the event of US activities that might require full compliance with SEC rules (e.g. issuing prospectus). In common with virtually all major competitors, the information is accompanied by text warning the investor of its limitations as an indicator of business value and risk.

**1988 - 1999:** The current Group Guidelines evolved from two reports published in 1988. Requirements for project maturity evolved gradually, but generally were far more lax than is considered necessary today. The following excerpts from the 1998 guidelines are typical of the guidance given in the period:

*"Technical Maturity: For a project to be technically mature, information on the resource volume, including its level of uncertainty, is such that an optimal project can be defined with an auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics. The plan may be notional or it may be an analogy of other projects based on similar resources. However, there should be a reasonable expectation that a*

8 December 2003

Confidential

*firm development plan can be matured with time. Projects do not have to have a completed development plan"*

*"Commercial Maturity: .. Projects generally have to demonstrate economic viability in order to obtain investment approval. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought."*

1990: Until 1989 proved gas reserves were constrained, under Group Guidelines, to volumes that had been committed to contract. Concerns were voiced that this approach was conservative compared with competitors, was more stringent than required by SEC rules and lead to complications in accounting (different figures were used for depreciation). The guidelines were relaxed to allow the inclusion of volumes that were reasonably certain to be committable beyond, or in addition to, the term of existing sales contracts. As a result, revisions to proved gas reserves amounted to 2100 million barrels of oil-equivalent, contributing 193% out of a total proved Reserves Replacement Ratio (RRR) for 1990 of 334%. This does not contribute to the currently perceived exposure.

1996: Following a sustained period of proved reserves decline in the early 1990s, there was considerable pressure, both external and internal, to correct performance. Major additions were made in 1996, predominantly revisions of reserves in traditional core areas of business but also including first bookings for the Venezuela risked service agreement and Oman Gisco.

1997-1998: Following on from the 1996 efforts to identify additional reserves, concerns were voiced that the Group's proved reserves disclosures were excessively conservative compared with competitors, that they did not sufficiently reflect shareholder value and that they resulted in accelerated depreciation charges. A LEAP Value Creation review was conducted, resulting in the recommendation that the Group abandon its probabilistic technique in favour of deterministic techniques, particularly for mature assets. This recommendation was driven mainly by the observation that competitors (notably Exxon in the North Sea) held substantially higher proved reserves than Shell for the same assets, mainly due to the use of "best estimates" of recovery from the "proved area" of the reservoir, which for mature fields tends to encompass the entire reservoir.

1998: The 1997 review recommendations were implemented in the Group Guidelines, including the advice to book "proved = expectation" developed reserves for mature fields.

8 December 2003

Confidential

This corrected the Group's under-reporting (relative to competitors) of mature field reserves<sup>1</sup>, but with the benefit of hindsight it left the Group vulnerable to net over-reporting of immature field reserves, brought about, for example, by registering reserves well in advance of the commitment to develop and including reserves outside the proved area as it would be defined by the SEC.

2000 – present: Technical and commercial maturity requirements for reserves disclosure were gradually tightened:

September 2000: "Successful completion of a Value Assurance Review (VAR) with sufficient definition supports technical maturity."

September 2001: "This should preferably be VAR3 (Concept Selection)" and "The project should be included in the annual Business Plan".

April 2002: "For major projects ... VAR3 must at least have been completed" and "Support to fund the project (must be) reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan."

October 2003: "... reserves in principle should not be reported until a project has been sanctioned (Final Investment Decision: FID). This requirement is to be viewed as mandatory for major projects (cut-off defined) ... For intermediate development projects (cut-off defined) concept selection (VAR3) must at least have been completed." The requirement to have the project included in the Business Plan was removed and replaced by the requirements that its "profitability must meet the Group's investment criteria" and that "funding by the Group is reasonably certain to be provided." This change was made to allow reserves for long-term projects, outside the Business Plan window, to be registered, subject to adequate justification of commitment to proceed.

With the introduction of the FID criterion for major projects in 2003, the Group's procedures were considered to be fully consistent in this regard with competitor practice and with the SEC's implied requirement to demonstrate "commitment to develop".

These changes were introduced prospectively: it was understood that the tightening of the guidelines would introduce exposures on retrospective bookings, but the (tacit) assumption was that exposures would be retained on the books pending the maturation of the projects concerned to compliance with the updated standards.

The changes were initiated prior to, but were spurred on by, the SEC's publication of guidance in March 2001 and by further clarification received both in public and through private correspondence since then (see 2.1 above). At this time, incorporation of the SEC's guidance into the Group Guidelines has focused primarily on the trigger for booking proved reserves. Current compliance across the full range of SEC rules and requirements is discussed further in section 3 below.

<sup>1</sup> In 2001 the SEC noted that the practice of reporting the expectation estimate of recovery from the proved area is commonplace in the industry, observing that: "Since the likelihood of a subsequent increase or positive revision to proved reserve estimates should be much greater than the likelihood of a decrease, we see an inconsistency that should be resolved"

8 December 2003

Confidential

### 2.3 Shell in the US: Shell Oil Company (SOC) / SEPCo

As a US-based company and a SEC registrant in its own right, SOC was very focused on SEC reserves rules (e.g. only deterministic methods were used, "reserves" meant proved – no emphasis on expectation). Before aligning with Group Guidelines in 2000, SOC/SEPCo required FID to book reserves for major projects. Middle-sized projects could be booked if they met investment criteria (with a track record of funding such projects), were likely to be executed (no legal issues) and were in the approved business plan. Still SOC was not at the "most strict" end of the interpretation range. For example, SOC allowed pressure gradient data for proved area water contacts, EOR reserves (without pilot) in a new field if the target reservoir was similar to a regional formation where the process had been tested, and proved undeveloped reserves for an entire major (multi-year) approved project even if budget funding was granted for only the first year of drilling.

Much more strict was Amoco (a frequent SOC partner in West Texas), who would only book project proved undeveloped reserves for those wells funded in the next year even if there was corporate commitment to the entire project (thus later year well reserves remained in probable until funded). This "strict" interpretation for undeveloped reserves was actually not too unusual (compare SOC's high historical ratio of undeveloped reserves to total proved with other US majors), perhaps because the basis for US income tax cost depletion was total proved reserves. Thus, while net income was reduced by very conservative proved reserves, cash flow was improved from deferred taxes.

Perhaps the biggest difference between SOC/SEPCo and Group (outside US) practices on proved reserves was not as much in the SOC guidelines but the rigour in assuring they were properly followed. As noted, SOC was very focused on SEC requirements and, typical of US companies, always had a strong audit process before reporting year-end reserves. Not only did this catch major "busts" but also fully emphasized to the staff how important following the guidelines really was – every reservoir engineer who reported a major proved reserves change had to "experience" a detailed audit of their reserves understanding and of their supporting technical work. Additionally this and periodic consulting provided a clear understanding of guidelines that removed much of the possibility for individuals to (mis-)interpret the rules.

Other contrasts:

- SOC included own use fuel in proved gas reserves until 2000 – Group Guidelines on this matter are more conservative than required by the SEC.
- SOC's "proved area" was based on the "one offset well location" rule, as supported by the SEC, whereas the Group Guidelines permit a more generous, geology-based definition of the proved area.
- SOC required a specific well location and development plan to be available before proved undeveloped reserves could be attributed.

8 December 2003

Confidential

## 2.4 Industry Interpretation of the SEC Rules

Apart from the insights summarized in 3.3 below, it is very difficult to know for sure exactly how competitors interpret the SEC rules, less still how these interpretations have changed over time.

SEC and industry (in general) were in agreement in the late 1970s when the regulations were written. However, since then the development and application of new technologies have caused some in industry to move away from the strictest interpretation of SEC rules, provided that these technologies can be defended as demonstrating the "reasonable certainty" that is the foundation of proved reserves. By the late 1990s the SEC rules (and 1978 technology) were quite different from industry practice in some areas (e.g. the requirement for a production flow test in support of "economic producibility" in the US deep water GoM). Nevertheless, some in industry were still very strict about following the SEC "letter of the law" – clearly true of those using consultant reserves evaluators (typically smaller companies) but also some majors (Amoco, see section 2.4). An informal gathering of major to middle-sized companies held in 2003 to discuss the "new" SEC position on Lowest Known Hydrocarbon found that most allowed the use of pressure gradient data to define the water contact for proved area, yet the SEC feels that only a well with a log showing the water contact can determine its location for proved area.

8 December 2003

Confidential

### 3. Current Consistency with SEC Rules

Despite the guidance that has been issued by the SEC, margin for interpretation exists on several aspects of implementing the rules. Thus there are still several aspects on which the current Group Guidelines could diverge from the strictest interpretation of the SEC rules and / or guidance. This is generally due to (sometimes fundamental) disagreement with the principles promoted by the SEC and the belief that investors are more reliably informed, on a more cost-effective basis, when a more reasonable view is taken of the geological and engineering data at hand. These interpretation differences are clearly highlighted in the Group Guidelines through a tabular explanation of the SEC's guidance on each key point and the preferred Group approach. In each case where differences exist, there are grounds for defending the Group's approach, at least in relation to the spirit and intent of the SEC rules.

In this section, the current Group Guidelines are assessed for compliance in terms of the trigger for reserves booking (3.1) and the volume booked (3.2). Insights into competitor practice are discussed in section 3.3.

#### 3.1 Trigger for Booking Proved Reserves

The introduction in 2003 of the FID criterion (or other public demonstration of commitment) for major projects has addressed, at least prospectively, one of the fundamental exposures in the Group's historical practices. Both ExxonMobil and BP are known to wait for project sanction before disclosing reserves for major projects, an approach that clearly is more compatible with the SEC's views as illustrated by the following specific guidance (March 2001):

*"Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved ... In developing frontier areas, the existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Investors must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves... Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc... An inordinately long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves."*

8 December 2003

Confidential

Less clear are the criteria appropriate for booking proved reserves in relation to relatively minor projects and / or incremental projects that may be executed beyond the initial phase of field development. The introduction of the Group's VAR3 criterion was designed to ensure that lesser, but still non-trivial, developments be subjected to a minimum level of subsurface understanding and technical definition in support of proved reserves attribution. This is deemed (internally) to be consistent with demonstrating that, in combination with profitability criteria, it is reasonably certain that the project will be executed and that the reserves registered as "proved" will indeed be produced.

However, this does not necessarily provide the guarantee of project execution that an investor (or the SEC) might require. Consideration might therefore be given to strengthening the criterion only to allow booking of reserves for VAR3-compliant projects if accompanied by a clear track record in the company concerned that (the great majority of) such projects are indeed executed.

### 3.2 Proved Reserves Volume Estimation

**Proved Area.** In establishing the proved area of a reservoir (i.e. the area to which proved reserves may be attributed), the SEC rules require that continuity of productive formation throughout the proved area be established with "certainty". This is well nigh impossible to demonstrate until a reservoir has been at least partially developed and placed on production for a period of time. In response to the problems raised by this, SEC guidance, reflecting historical practice generally in the US, is that the proved area is deemed to comprise one offset well location from each existing penetration (i.e. a total of nine well drainage areas around an existing well). This arbitrary constraint, which attributes little value to geological knowledge and experience, can lead to some curious (even bizarre) consequences.

For example, consider a partially developed field in which sufficient performance history has been acquired to justify doubling the planned well density through infill drilling. With regulatory approval for reduced well spacing, the infill plan can reduce the "proved area" around each existing well (by shrinking the size of the proved, undeveloped locations that offset the existing well), causing bookable proved reserves to be reduced simply as a consequence of the infill development decision, which in fact is born of a greater understanding of (and hence certainty in) reservoir performance than had existed in the first place.

Whilst describing the SEC's preferred approach, the current Group Guidelines leave plenty of margin for reserves estimators to assign proved area on a more geologically sound basis.

This has implications for cost allocation. FASB and SEC rules require that any expenditure incurred on drilling wells outside the proved area must be denoted Exploration Expenditure and accounted for accordingly. Strict application of the



8 December 2003

Confidential

SEC guidance on proved area would inevitably cause Expex for the Group to increase and development Capex to reduce by the same amount, all other things being equal

**Analogues:** In citing analogue reservoir performance in support of improved recovery reserves, SEC guidance may be taken to imply that such analogues should be reasonably local (say, the same geological play). There are examples in the Group where the analogies cited are actually quite remote from, although geologically similar to, the field in question.

**Lowest Known Hydrocarbon (LKH):** Pending resolution of disagreement with the SEC, or at least a clear public statement of the procedure to be adopted, the Group Guidelines continue to reflect that reliable pressure gradient data may be used in establishing the vertical extent of hydrocarbon accumulations and, hence, for proved reserves attribution. The current SEC view, which emerged during 2003, is that the proved area must be constrained vertically by the limits of logged hydrocarbon-bearing formation.

**Fuel Gas:** The Group excludes gas consumed as fuel and flare from proved reserves disclosures, whereas the SEC allows (even expects) at least fuel gas to be included. For convenience, competitors may in fact be disclosing the full wellhead gas production stream in some cases (i.e. including also flared gas). Inclusion of fuel gas would increase Group proved reserves by approximately 300 million barrels of oil-equivalent (about 1.5%, or a 20% annual RRR benefit if incorporated as a revision rather than a restatement). Implementation is under consideration, but would require changes to financial accounting practices in the operating companies (fuel gas consumption would need to be charged as an Operating Cost, resulting in a corresponding additional revenue item).

**Production Sharing Contracts (PSCs) and other Economic Entitlement-based Reserves:** Proved reserves entitlements are calculated on the basis of the Group's Mid-Project Screening Values (Mid-PSV) of oil and gas price, whereas SEC rules imply that the actual price on the date of the estimate (31 December each year) must be used. When actual prices are substantially higher than Mid-PSV, this causes entitlements to be overstated, since under such conditions fewer entitlement barrels are required to recover costs incurred.

Entitlement at 31.12.2002 was, in principle, overstated by some 290 mln boe due to the use of Mid-PSV, rather than actual year-end price (Brent US\$ 28.66 per barrel).

This effect is offset partially by the extension of economic field life in tax/royalty situations at high price relative to Mid-PSV. Further offset is provided by the exclusion of reserves in relation to tax paid on the Group's behalf (usually) by the National Oil Company partner in some PSCs. SEC rules allow bookings in relation to such payments and many competitors include them, as well as taking a similar approach to the Group on price assumptions. Thus, while the full rigour

8 December 2003

Confidential

of the SEC rules is not fully applied to each contract and licence, the overall effect on Group proved reserves is demonstrably immaterial, whilst there are considerable logistical benefits in terms of being able to estimate proved reserves in advance of year-end.

Group Guidelines were updated in 2003 to suggest that low cost assumptions be made for PSCs, which would help to ensure conservatism in the resulting proved entitlement estimate.

### 3.3 Competitor Practices

Detailed insights into competitor practices is generally difficult to come by, particularly when revelation might risk exposure of non-compliant practice. The information presented below represents our current impressions of competitor practice, coded as follows in relation to compliance with SEC rules:

**Mobil:** Prior to the merger with Exxon, Mobil was one of the most published US majors on the subject of reserves and was noted for its support of probabilistic methods. However on closer inspection, this was for expectation (proved plus probable) reserves – they actually used deterministic methods for proved reserves. SEPCo discussions with Mobil when Acta was first formed confirmed that their basic reserves interpretations were similar to SEPCo's at the time.

**Amoco:** Prior to takeover by BP, Amoco in the US was notably stricter in interpreting the SEC rules than SEPCo (see 2.4).

**Enterprise:** Upon acquisition in 2002 it was discovered that Enterprise's approach to reserves booking was more relaxed than Shell's (at the time), a factor likely to be common among small / mid-sized companies with an eye on potential buyers. Having said this, the techniques they applied in the US were in line with general US practice. Some 10% of their proved reserves did not meet the Group's requirements for new reserves bookings in terms of project maturity and consequently they were not booked by Shell (Norway Skarv and Italy Tempra Rossa Phase 2). Furthermore, much of the reserves quoted for KMOC (Russia, again more than 10% of the Enterprise total) appeared to be seriously exposed in terms of commerciality, despite being "supported" by independent certification. These have since been divested to Marathon, who subsequently quoted proved reserves of approximately 1/3 those reported by Enterprise (and Shell) per equity point. Several other projects appeared to have been booked far in advance of project sanction.

#### **ExxonMobil:**

Reports "wellhead" gas production as reserves.

Appears to rigidly enforce proved area / deterministic methods, backed up by extensive, well staffed annual global audit effort.

Does not book reserves before project sanction (perhaps one or two exceptions historically).

Suspected of "managing" RRR performance by deferring bookings / suppressing revisions in years of surplus – very predictable and stable RRR trend – indications that this is becoming hard to sustain.

8 December 2003

Confidential

Probably the most rigorous of all majors across their global portfolio.

**BP:**

Reports "as sold" gas production as reserves.

Appears to rely heavily on probabilistic techniques – suspected of booking very aggressively in terms of volume – few material revisions, whereas SEC rules clearly require that a healthy contribution from annual revisions would be expected. Internally revisions are seen as "something to be avoided", possibly causing revisions to be classified as Improved Recovery or Extensions in some cases.

Does not book reserves before project sanction (practice established based on project approvals by UK authorities).

Reserves (including PSCs) are estimated based on business planning reference price, not year-end price.

Indications that they are gradually waking up to the SEC requirements for increased rigour in proved reserves estimation. Considered likely to be at risk under increased SEC scrutiny.

Fairly high bookings from extensions and discoveries in 2001 (including Thunderhorse) allowed BP to balance overall bookings and take negative revisions in that year (Lake Maracaibo). In August 2003 BP revised downwards its estimate of oil and gas reserves it expects to book for its Russian TNK-BP joint venture because SEC rules will not allow booking beyond the end of licence periods (a well known constraint that it is surprising BP did not take into account when originally quoting its reserves estimates).

**Total:**

Reports "wellhead" gas production as reserves where there is a gas sales contract in place – otherwise reports no associated gas reserves.

Reserves are believed to be estimated based on business planning reference price, not year-end price (Total is much more exposed to PSCs than Shell).

Indications that they are gradually waking up to the SEC requirements for increased rigour in proved reserves estimation. Of the majors, Total on average reports the highest rate of revisions, suggesting that their approach to initial booking is conservative, although since Improved Recovery changes are rarely, if ever, reported the Revisions category may be inflated by such changes.

**Chevron Texaco:**

Little insight: externally perceived as being aggressive on volume – possibly also at risk from enhanced SEC scrutiny.

Appears to follow year-end pricing on PSCs (large negative revisions in 1999 quoted as being due to reduced cost-recovery entitlements in Indonesia due to high year-end prices).

Chevron had internal rules for using seismic to book proved reserves and booked volumes meeting those criteria.

Has a full-time Reserves Audit staff to review proposed bookings at least annually.

There appears to be no attempt to manage RRR, e.g. through balancing high extensions/discoveries with low revisions. However, revisions generally are at a low level with, like BP, Improved Recovery regularly exceeding revisions (indication of aggressive volume bookings).

8 December 2003

Confidential

#### 4. Potential Reserves Exposures

The following tables summarize the proved reserves exposures as currently identified:

*Proved reserves which are likely to be considered as not compliant by the SEC*

Country	Field	Non-compliant reserves as at 31.12.2002 (est. mln boe)		Reason
		Proved	Expectation	
Australia	Gorgon	557	785	No FID or investment commitments
Nigeria	Onshore (SPDC)	720	ca. 1400	No mature plans / projects
Oman	Existing fields	234	240	Immature projects, (some) unproved techniques
LKH	Various	ca. 300	0	New SEC guidance
PSCs	Various	291	0	Oil / gas price assumption in calculation of reserves entitlement.
<b>TOTAL</b>		<b>2102</b>	<b>2430</b>	

*Proved reserves which might be considered as not compliant by the SEC*

Country	Field	Potentially non-compliant reserves (est. mln boe)		Reason
		Proved	Expectation	
Nigeria	Onshore (SPDC)	814	ca 1600	Plans/projects in progress (but not VAR3-compliant)
Oman	Existing fields	150	0	To be firmed up in short-term (2 years)
Kazakhstan	Kashagan	380	500	Government may not approve plan. Technical definition of proved area.
Others	e.g. Corrib, Tempa Rossa	ca. 200	270	No approved plan
<b>TOTAL</b>		<b>1544</b>	<b>2370</b>	

The reserves identified as likely to be not compliant with SEC guidelines represent 11% of the Group proved reserves (excluding oil sands), while the potentially non-compliant volumes would raise this to 19%. The corresponding figures for expectation reserves would be 7% and 15% respectively.

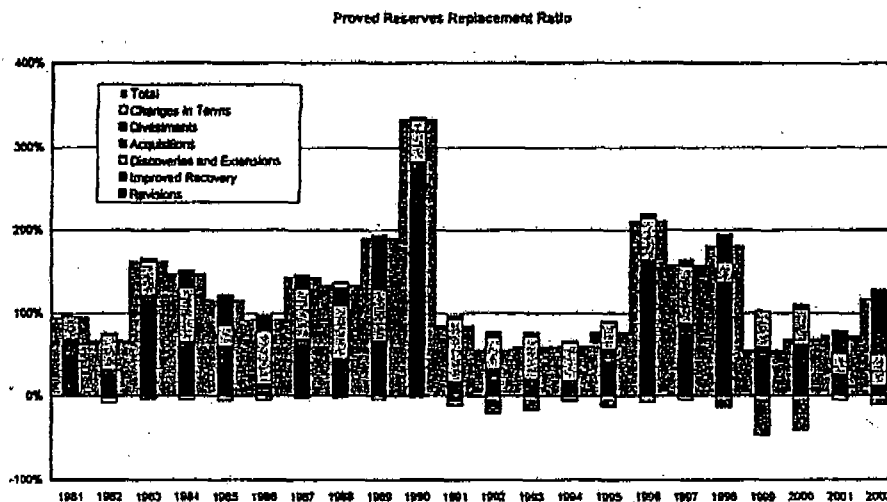
The main exposures were predominantly booked in the period 1997 – 2000. There follows a description of each (Gorgon, SPDC, Oman, LKH, PSC and "others"), after an explanation of the historical context. The manner in which each would be reclassified, and the prospects for re-booking in future are discussed in section 6 below.

8 December 2003

Confidential

#### 4.1 Group Context

The following chart illustrates the context in which the exposures were created:



During the 1980s the Group underwent a period of sustained proved reserves growth, with annual RRR generally exceeding 100%. This culminated in 1990 with a record in modern times of 334% RRR, driven mainly by the change to proved gas reserves reporting (see 2.2).

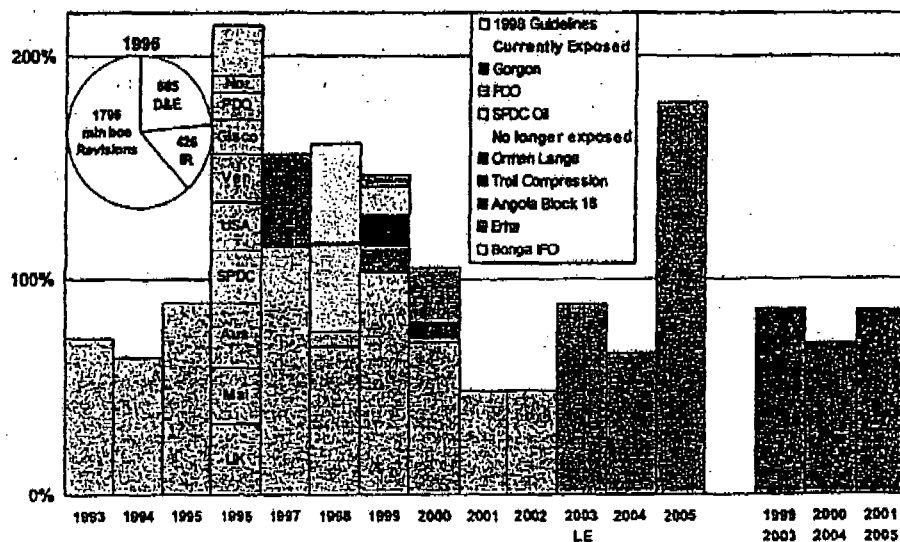
By contrast, during the early 1990s there was a sustained period during which new reserves additions consistently failed to keep pace with production, such that by the mid-1990s the pressure to correct the situation was severe, both from the market and from an internal growth objective. Substantial additions (largely revisions) were made in 1996 and a heightened level of RRR performance was sustained through the next two years, fuelled in part by the implementation of the revised "deterministic" Group Guidelines in 1998. However by 1999 and 2000, new reserves additions were becoming progressively harder to identify, ushering in a new period of reserves decline (excluding acquisitions) that the Group is currently struggling to break out of.

It was during the period 1997 – 2000 that the bulk of the currently identified exposures were created. Although the bookings were made consistent with the Group Guidelines in force at the time, with hindsight the effect has been to accelerate bookings into that period which, under the current guidelines, and under the current interpretation of the SEC rules, might more appropriately have been deferred to future years.

8 December 2003

Confidential

## Proved RRR: Organic (excl A&amp;D), excl. the effect of Sakhalin M1, Incl. AOSP



In essence, the proved reserves volumes that are currently seen as exposed are in this situation because of recent guidance from the SEC on two issues:

1. Proved undeveloped reserves need to be covered by a firm commitment to development (FID, AFE, MOU etc) before they can be booked as proved,
2. Proved reserves cannot be declared for volumes below levels penetrated by the drill bit (Lowest Known Hydrocarbons, or LKH).

The first item, SEC guidance on which was issued in 2001, has been followed by gradual changes in the Group reserves guidelines since 2000 (see 2.2). The second item arose out of correspondence with the SEC during 2003.

The exposed volumes in SPDC, PDO and Gorgon are affected by the first of these rulings, the LKH volumes by the second.

Many of the SPDC and PDO volumes had been booked during the 1990s, at a time when Group reserves guidelines required only technical and commercial (not necessarily economic) maturity of the associated projects. Many projects had proper Field Development Plans (FDPs) associated with them, e.g. those prepared by the Nigeria Studies Team. However, not all projects needed to have been properly studied and documented. Notional plans, based on analogue developments in the same or neighbouring fields were acceptable and in accordance with then prevailing Group guidelines, provided that there were identified activities and preliminary economics. The recovery factors associated with such notional plans were often assumed or inferred by analogy.

8 December 2003

Confidential

*Awareness and Response*

Over recent years, concerns have gradually been accumulating amongst reserves coordination staff over the status of some proved reserves elements in relation to the SEC's evolving guidance on, and the Group's evolving understanding of, the applicable rules.

Group External Auditors have questioned the retention of Gorgon on the books, and the overstatement of PSC entitlements have been highlighted frequently in their external review of the Group's proved reserves statements. At the end of 2002, and possibly in response to a fundamental shift in the extent to which individuals and organizations feel themselves to be accountable (pursuant to Sarbanes-Oxley), Group External Auditors expanded the list of items that they felt possibly to be non-compliant, feeling that a record of their opinion should be preserved on file. Notwithstanding this, the Group's argument that the net effect was immaterial in relation to total Group reserves was accepted.

Furthermore, through the linkage of proved reserves additions to business and individual performance score cards, it is possible that situations occurred in which staff involved with reserves estimation were subjected to pressure to propose proved reserves changes that might not have been fully compliant.

Actions to address the perceived problems in SPDC and PDO were begun by freezing the affected reserves at the figures reported in 1999 and 2000 – no new additions were allowed and the balance was reduced annually by production.

Beginning in 2002, these concerns were summarized and brought to management attention through the compilation of a Potential Reserves Exposure Catalogue, which has been updated typically at 6-month intervals and which has been included in relevant notes for information to the EP Executive, CMD and the Group Audit Committee. All items covered by this note have been included on this list, with the exception of Kashagan.

Actions were taken to address some of the more obvious entries that have appeared on this Catalogue, such as the debooking of significant non-compliant volumes in the Nigeria deep water province (Bonga, Erba: 130 mln bbl) in 2002 and the investigation work completed in 2002 to assure SPDC's legal rights to licence extension. Nevertheless, other items on the catalogue were retained, each with a justification that was considered plausible and defensible (pending work to address the exposure through project maturation). Consequently, the view was taken that the exposures should indeed be highlighted and addressed as a matter of priority, but that no corrective action was warranted in the meantime in relation to external disclosures.

Further measures to improve the controls around reserves disclosure were introduced in 2003. A Reserves Committee, comprising senior EP managers and the Deputy Group Controller, was established to oversee procedural matters.



8 December 2003

Confidential

Regional Reserves Challenge sessions were introduced to help assure compliance of all proposed material reserves changes. It is likely that further measures will be taken in 2004, the details of which have yet to be defined.

What has changed recently is the completion of the study and audit work in PDO and, especially, SPDC. These revealed the full extent of the potential exposures in these countries that previously had been suspected but which until now had not been thoroughly enumerated. When combined with the previously known exposures, this caused the total position in effect to be recategorized from "of concern, but acceptable" to "material and, potentially, warranting corrective action".

#### 4.2 Gorgon

Gorgon is a giant gas field on the offshore Australian NW Shelf in which Shell has 2/7 equity. ExxonMobil has 1/7 and operator ChevronTexaco 4/7. The field is far removed from existing infrastructure and the gas has a large inert fraction. A market for the gas is likely to be found in the Pacific rim in the long term, but this is as yet far from mature. Because of the remote location, development economics, while still positive, cause the project to face severe competition from other projects within (and outside) the Group.

Proved reserves were declared for Gorgon in 1997, in line with then prevailing Group reserves guidelines. The booking was supported by Letters of Intent to sell Liquefied Natural Gas (LNG) into the Asian market and what was believed to be imminent project sanction. The booked volume is 557 million barrels of oil-equivalent, including natural gas liquids, making this the second largest single-field booking in the Group's portfolio after Groningen. Following the Asian economic crisis the LNG sales contracts never materialized and since then field development has struggled to progress, impeded in part by competitor activity in the region. Current Group reserves guidelines, requiring FID for a project this size and at least Heads of Agreement for LNG sales contracts, would not have allowed this volume to be booked. The booking was maintained at 1.1.2003, pending a decision on the way forward.

The proved reserves booking is clearly exposed to the SEC's guidance on commitment to develop in "frontier areas", not least due to the lack of a ready market for the product and excessive delay in bringing the development project to fruition. Progress appears to be being made towards FID in 2005, with an option available for sales contracts covering approximately half the reserves. However, this project also represents a substantial Investor Relations issue since the market does not appreciate that reserves have already been booked and it will be expecting substantial reserves additions once FID and firm sales contracts are announced. Neither of the partners in the field has booked reserves to date.

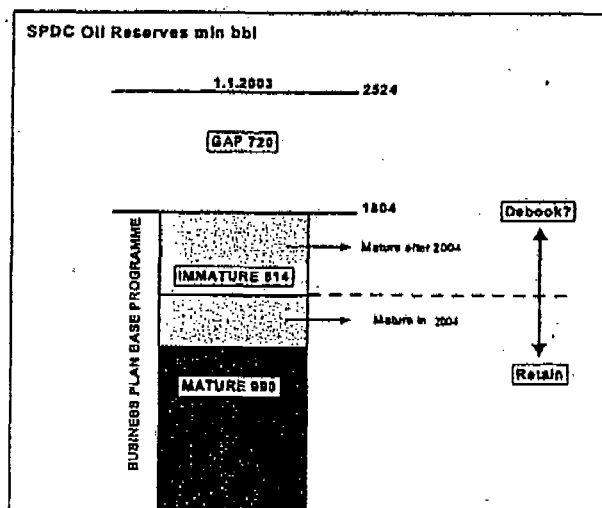
8 December 2003

Confidential

#### 4.3 SPDC Nigeria Oil

##### *Current Status*

SPDC's proved oil reserves at 31.12.2002 were 2524 million barrels (mln bbl) Shell share. However, SPDC's Business Plan "Base Programme" only covers a volume of 1804 mln bbl and of this, only 990 mln bbl fully complies with the current Group Guidelines.



The 720 mln bbl (Shell share) gap between reserves booked and the base programme implies that no realistic projects have been identified to cover this, now highly exposed, volume. While SPDC's total resource base (expectation reserves and scope) is very large, additional volumes cannot be accommodated in the base programme before about 2010 within current constraints, particularly funding. Therefore it will not be possible to bridge the 720 mln bbl gap between the base programme and the reserves at 1.1.2003 for at least several years.

A major reserves review that SPDC carried out in the second half of 2003 also identified that a significant number of projects in the base programme (together 814 mln bbl) did not fulfil the recently tightened Group reserves guidelines which required VAR3 or FID for compliance with SEC rules, as they are now understood. An important reason why these projects were now seen as immature was the lack of Associated Gas Gathering (AGG) plans for the field / project in question. With the 'flares-out-by-2008' policy imposed by the Nigerian Government this meant that oil production would have to be shut in, unless there was an export or utilisation route for the associated gas. Many projects were found to be lacking firmness of definition, i.e. they were still a long way from a possible request for funds. Other projects were found to be notional only, with no study or development plans defined at all. Whilst such projects

8 December 2003

Confidential

would have been acceptable for booking as proved reserves under pre-2000 Group guidelines, they were now no longer in compliance.

The 814 mln bbl in the base programme that does not fully meet the guidelines can be broken down as follows:

	mln bbl
<b>Developed Reserves:</b>	
No AGG solution by 1.1.2008	86
Facilities vandalised	19
Reservoir exposure – no plans yet defined	18
Total	123
<b>Undeveloped Reserves:</b>	
Ongoing studies	150
Remedial action plan	446
No plans yet defined	96
Total	692
<b>TOTAL</b>	<b>814</b>

It is unlikely that much of the remaining exposed volumes will be matured during 2004. Some 86 mln bbl is associated with developed reserves that have no AGG solution in the base programme beyond 1.1.2008 (the target date for implementing the "flares out" policy). As such this volume will probably be removed from next year's programme. Some 19 mln bbl also lies in fields which have vandalised surface facilities (including the Northern Swamp). There are 96 mln bbl of undeveloped reserves and 18 mln bbl of developed reserves with various reservoir, AGG and project exposures for which firm plans have not yet been defined. Some of this will be addressed by the asset teams in 2004, but the volume that can be matured by end 2004 is uncertain at this stage.

As indicated above, studies are ongoing to mature 150 mln bbl of the exposed volume. These are in the Gbaran/Ubie (75), Oguta (14) and Ughelli (60) nodes. Gbaran/Ubie is a major integrated NAG/oil/ AG project that will supply both NLNG Trains 4/5 and 6. It has taken VAR3 and is due the take VAR4 in mid-2004. The exposure related to this volume is therefore relatively low and there is a high degree of confidence that it will be fully mature by end 2004. The other studies are at a lower stage of maturity by comparison and there is more uncertainty about the viability of AGG facilities. As such, there is a relatively low level of confidence that these will be fully mature by end 2004.

A remedial action plan has also been initiated which will target a further 446 mln bbl of the exposed volume. This consists of 18 field studies and will take an estimated 42 man-years of effort. Much of the work will have to be carried out in Nigeria, but will be supported by external EP staff. The plan aims to complete

8 December 2003

Confidential

80% of this work by end 2004, but this is a stretch target with 50% being a more realistic 50/50 estimate (i.e. 220 mln bbl reserves estimated to be matured by end 2004). The studies will also address about 140 mln bbl that are not currently covered by the base plan, but which are in the same fields to be studied (principally Nembe Creek, Santa Barbara and Soku). However, it is unlikely that significant additional volumes would be mature by end 2004 and it is also questionable whether the related development projects can be accommodated within the base programme.

Based on the above assessment, there is a high level of confidence that the "fully mature" volume will increase from 990 to about 1300 mln bbl by end 2004. This assumes that Gbaran/Ubie takes FID and 50% of the remedial action plan is carried out. The volume would increase to about 1450 mln bbl if 80% of the ongoing studies and remedial action plan could be completed by end year. However, this is considered a stretch target.

In all, there is little doubt that there are significant oil resource volumes within SPDC's licence areas and that these provide a solid base for sustainable production within the company. Exploration drilling continues to make material additions to SPDC's already large portfolio of discovered oil resources. The main issue is how much of the discovered volume can be booked as proved reserves. Under the Group's current understanding of the SEC rules, it is questionable how much of the current SPDC oil bookings, beyond the 990 mln bbl of "fully mature" reserves, could withstand external scrutiny, should the need arise. This view was supported by a review of the current status and maturity of SPDC's proved reserves by the Group Reserves Auditor in September 2003. This in no way reduces the longer term potential and is only a reflection of the volume that can be considered fully technically and commercially mature at a given time.

#### *Historical Reserves Bookings*

SPDC's reserves steadily increased during the 1990s:

- There was a significant step-up in production rate from 1989 to 1991 and increased reserves were therefore required to be able to sustain production levels in the long term.
- SPDC was gearing up for further growth, although this was repeatedly frustrated, principally by funding constraints, community disturbances and political instability.
- A Reserves Addition Bonus was provided under the 1991 Memorandum of Understanding (MOU), which encouraged the JV operators to increase their reserves base.

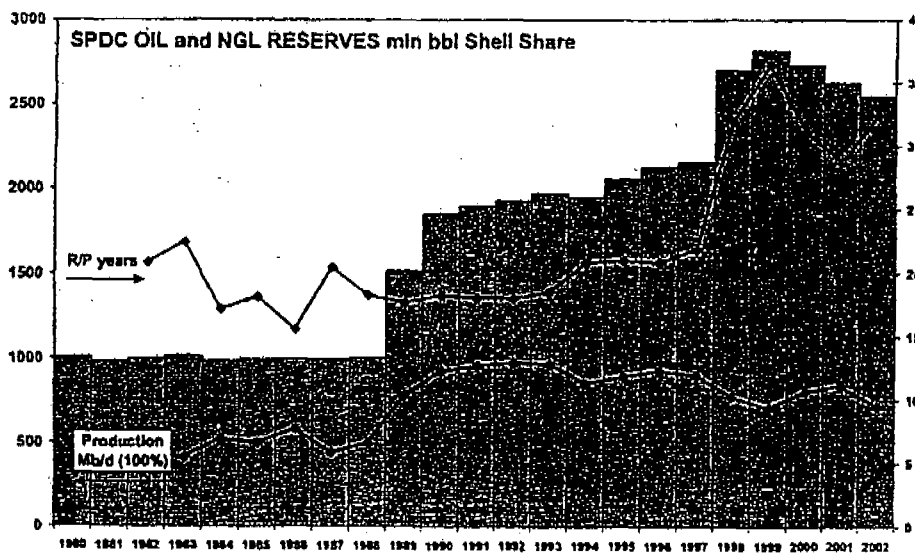
As shown below, there was a fairly stable reserves to production (R/P) ratio of 18 years from the early 1980's through to 1993. However, this ratio started to increase from 1994 onwards, partly owing to a decline in actual production rates.

8 December 2003

Confidential

A sizable proved reserves addition (some 580 mln bbl oil Shell share) was booked by SPDC in 1998, following a major review of the portfolio of projects and of reservoir blocks with negative reserves (conservative proved volumes now overtaken by cumulative production). Approximately half of the addition was also attributable to revised Group reserves guidelines which stated that, in line with industry practice, proved reserves should equal (or be close to) expectation reserves in mature fields, of which SPDC has many.

A "moratorium" was introduced on further reserves additions in 1999 owing to concerns about the ability of the business to deliver the stated proved reserves in view of further delays to production growth. Declared proved reserves were maintained independently over the period 2000-2003, not linked to any sum of individual projects or fields. There was also concern that it would not be possible to accommodate additional volumes prior to licence expiry in 2019. However, detailed investigations in 2002 showed that reserves do not need to be constrained by licence expiry as the Government has an obligation to renew licences (so long as contractual commitments have been met) and there is already an established track-record of JV licence renewals. While this removed the significant exposure regarding proved reserves volumes beyond end-of licence, it still did not resolve the disconnect between individual projects and total proved reserves.



EPS, EPF, EPT

27

Proved Reserves Dec 2003 Part 1 CMD doc

FOIA CONFIDENTIAL  
TREATMENT REQUESTED

V00010469

8 December 2003

Confidential

*Future Outlook*

Any SPDC oil reserves that are de-booked at this stage would be reclassified as Scope for Recovery (SFR). The de-booking would also trigger a reclassification of expectation reserves to SFR<sup>4</sup>.

The following charts show a projection of future reserves bookings assuming that a de-booking is made of 1224 mln bbl, down to 1300 mln bbl. The de-booking would reduce the R/P from the current level of some 32 years down to less than 12 years – low by comparison with the potential prize associated with SPDC's resource base, but more in line with the average for the Group as a whole. At this starting level it will be essential to establish and maintain a reserves replacement ratio in excess of 100%.

It has been assumed that a volume equivalent to the 814 mln bbl exposed in the current base programme can be matured over the next three years (2004-2006). It would be impractical to mature a larger amount, as these volumes are needed simply to underpin the base programme and this is already constrained by factors such as funding. No reserves additions would be made in 2004 as study efforts in this year would be aimed at clearing the 310 mln bbl exposure that would remain under this de-booking assumption.

Additional reserves booking after 2006 would be mainly associated with large integrated oil and gas projects such as Oguta or Otumara. The projections are based on maturing 200 mln bbl a year.

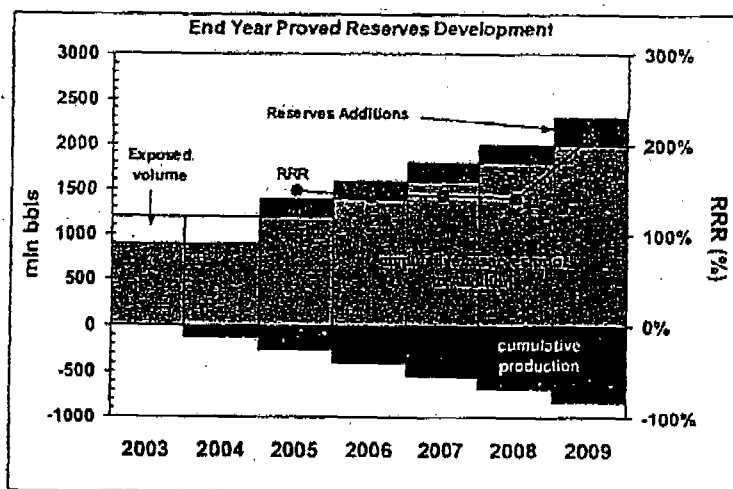
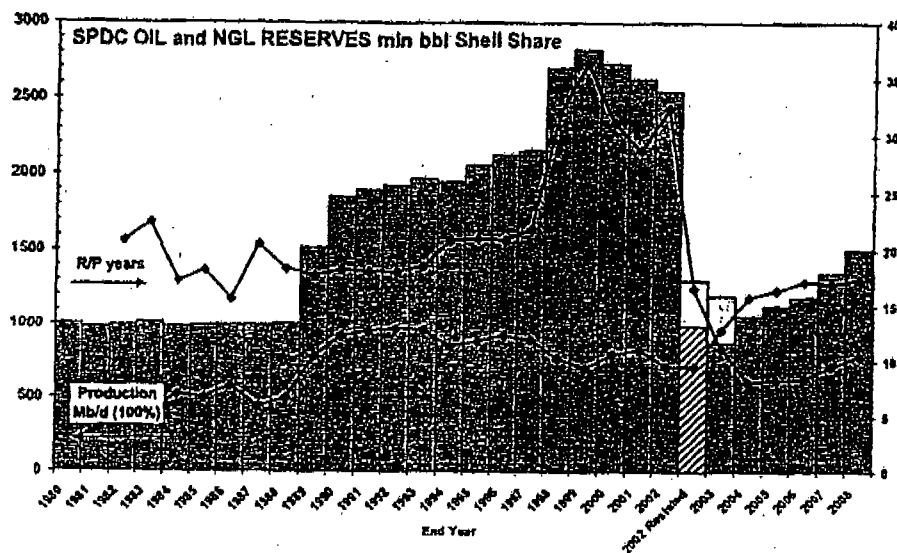
The projections suggest that it would be impractical to increase the R/P ratio back to historical levels under the current interpretation of the SEC guidelines. However, this does not change the underlying fundamentals of the programme, and only indicates that some of the later activity in the programme will not meet the more stringent current reserves criteria until such time that the required level of project definition has been achieved.

---

<sup>4</sup> SPDC's expectation reserves at 31.12.2002 stood at some 49 bln bbl Shell Share. However, under current guidelines a reservoir should not carry expectation reserves unless it also carries a proved volume. A large number of partially appraised fields and un-appraised discoveries would be reclassified on this basis.

8 December 2003

Confidential



Further reserves bookings are expected for gas. A net booking of 200 mln boe is expected in 2003 associated with NLNG Trains 4/5 and Train 1-3 production beyond 2019, (offset by a reduction in domestic gas volumes). A further 150 mln boe is expected in 2004 associated with Train 6 and the re-rating of Trains 1-3 and 140 mln boe is expected in 2005 associated with the gas supply to Afam and WAGP.



8 December 2003

Confidential

*Other Impacts*

- SPDC currently has an outstanding Reserves Additions Bonus (RAB) claim for US\$385 mln. The President has recently requested a negotiated settlement be achieved by end 2003. SPDC are seeking between 30 and 50% of the full amount. The claims are based on expectation technically recoverable volumes, rather than SEC proved reserves.
- While in principle a de-booking of SEC proved reserves should not impact on RAB, this is likely to undermine the current resolution process, or would jeopardize relations if a settlement were agreed just ahead of a de-booking. This would put US\$115 to 170 mln at risk.
- There could be other reputational impacts as the Government reports consolidated reserves figures to OPEC as a key input in quota discussions. As SPDC constitutes about 50% of total country reserves, an external disclosure indicating that estimates have been overstated could negatively impact the Government's position.
- The Government has recently presented a new policy and programme for the industry called "Structures for Sustainable Growth 2003-2007". This was developed by the new GMD of NNPC, Funsho Kupolukun, while Presidential Adviser. It recognises a potential shortfall on reserves targets and links this in part to multi-nationals sitting on large tracts of undeveloped acreage. A de-booking could therefore increase the risk that SPDC is forced to relinquish dormant licence areas.

In view of these factors it is recommended that, if any debooking of proved reserves in SPDC is made, it should not be identified publicly with Nigeria. Public statements should be confined to the 20-F geographic area concerned ("Eastern Hemisphere, Other"), noting that further details are confidential in view of host country sensitivities.

8 December 2003

Confidential

#### 4.4 PDO (Oman)

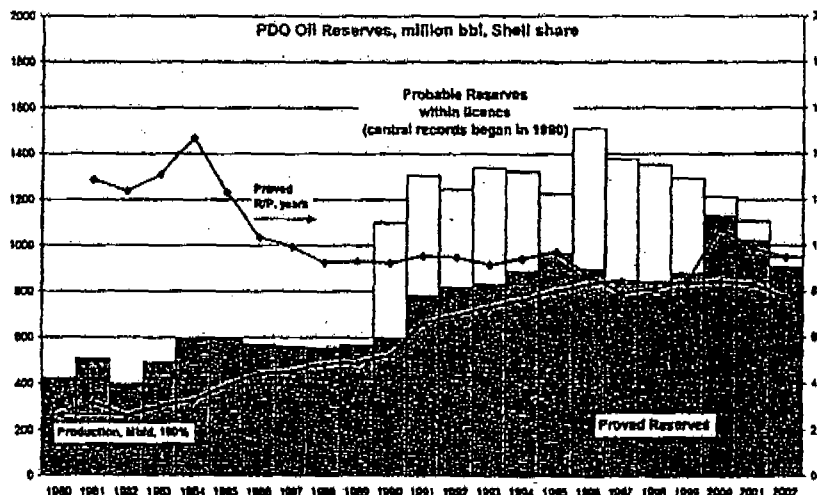
##### *Current Status*

Some 234 - 386 mln bbl (Shell share) proved reserves are exposed relative the current Shell Guidelines due to lack of project maturity and / or proof of improved recovery concept.

A STOIP and Reserves Review was completed in December 2003, which concluded that Expectation reserves are exposed by some 240 mln bbl (Shell share) due to lack of supporting development plans, the problem being (potentially) exacerbated for proved reserves due the influence of licence expiry in 2012 and the conservatism required for proved reserves volume estimation.

The medium-term studies plan should ensure that the bulk of the exposure is addressed by 2008. Furthermore, progress is being made towards ensuring the Group's continued participation in PDO operations post-2012, which would yield substantial additional proved reserves entitlements. However, at this time it is unlikely that the full Group share proved reserves (907 mln bbl at 31.12.2002) would withstand external scrutiny.

##### *Historical Reserves Bookings*



In the late 1990s PDO had a portfolio of proved reserves projects of varying maturity, most or all of which were in compliance with the then prevailing Group guidelines. Submitted Group share proved reserves were the sum of individual field proved reserves, as they should be. These individual field proved reserves were rather low in comparison with expectation (proved + probable) within licence reserves, particularly when account was taken of their fields' maturity (the average ratio was only 68% at the end of 1999). The reason for this was that PDO (and the Oman Government) have historically had interest only in expectation reserves (the basis for reserves addition bonuses), with the result that

8 December 2003

Confidential

proved field reserves were hardly updated from their initial, low values. This was highlighted in the 1999 reserves audit.

PDO were strongly advised by SIEP in 2000 (pursuant to the revision of Group reserves guidelines in 1998) to correct the low proved-expectation reserves ratio. Individual field proved volumes had still not been addressed, but PDO were advised to make an upward correction to proved reserves based on a continuation of the then prevailing 850 Mb/d plateau for eight years, followed by a relatively steep (20%) decline. With hindsight, and the results of the 2003 review, it might have been more appropriate to correct the expectation estimate down rather than the proved estimate upwards. Nevertheless, at the time the understanding was that this revised proved volume would become underpinned by proper re-assessments of proved reserves and proved forecasts in individual fields, but, due to the attention required by serious production decline problems shortly thereafter (see below), this did not happen. At the end of 2002, the remaining R/P ratio for proved reserves was close to the remaining lifetime of the licence (10 years), implying that current production rates must be sustained throughout that period, and be underpinned by projects that fully comply with SEC rules, for the proved reserves statement to be maintained. As such, the proved reserves estimate is now seen as unrealistic, both by PDO and by its shareholders.

Faced with the serious production decline trends in a number of fields, PDO committed to the comprehensive review of their STOIMP and reserves estimates (mentioned previously) by an integrated study team staffed mostly by SIEP-EPT. This study team largely confirmed the in-place volumes carried by PDO but recognised, with PDO, that reserves in a number of fields (most notably Yibal and Marmul) were somewhat overstated. The study also highlighted that a significant number of future development projects, targeting the expectation and proved undeveloped reserves, were immature to very immature and that only a small fraction (some 20%) of these projects carried reserves that would fulfil the latest (2003) Group reserves guidelines.

#### *Other Impacts*

- PDO Reserves Additions Bonuses (RABs) are evaluated with reference to an expectation, not proved, estimate of recovery. In view of the 2003 review finding that expectation reserves may be overstated, the issue of RAB rebates is under discussion with the Omani authorities and agreement in principle exists to phase any such rebates over a period of time, tied to individual field studies. Nevertheless, this matter is extremely sensitive, and the subject of confidential negotiation.

Consequently it is recommended that, if any debooking of proved reserves in PDO is made, it should not be identified publicly with Oman. Public statements should be confined to the 20-F geographic area concerned ("Eastern Hemisphere, Other"), noting that further details are confidential in view of host country sensitivities.

8 December 2003

Confidential

#### 4.5 Lowest Known Hydrocarbon (LKH)

In 2003 the SEC advised the Group through correspondence that its interpretation of the SEC LKH rule was such that no proved reserves may be attributed to any part of a reservoir that is deeper than the lowest point at which (productive) hydrocarbons have been penetrated (subsequently revised verbally to "logged") until performance history is available in support of a higher volume. This view was repeated verbally at the October 2003 SPEE forum on the application of the SEC rules. Whilst the SEC's views are by now widely known in the industry, there has to date been no formal notification of this advice to the industry in general.

The SEC's logic appears to stem from its recent attempt to insist that a production flow test must be conducted, to demonstrate economic productivity, before proved reserves could be assigned. This was rejected by the industry on the grounds that adequate rock and fluid data acquisition, coupled with analogy, has been demonstrated over many years to provide sufficiently reliable estimates of productivity. The SEC reasons that, since such techniques require the measurement of rock and fluid properties, it is not consistent to attribute proved reserves to volumes of rock that have not been penetrated and logged.

The Group objects to this interpretation on the grounds that it prohibits the use of industry-standard techniques for establishing, with reasonable certainty, the location of fluid contacts in the reservoir. Such techniques include the use of pressure gradient data and, particularly as employed on the US Gulf of Mexico, the careful analysis of 3D seismic attributes. SEPCo has developed clearly auditable, reliable procedures for the latter, not least in response to the observation that many operators in the GoM appear to use similar techniques in support both of field development planning and proved reserves attribution. These techniques were presented to the SEC staff by SEPCo in a face-to-face meeting in August 2003, but despite finding merit in the techniques the SEC responded (in writing) that it had not been persuaded of their applicability for proved reserves attribution.

The Group also objects to the manner in which the SEC has provided this advice, given that no clear public statement has been published and that Shell appears to have been singled out among the majors. No major competitors appear to have received similar advice, despite being in correspondence with the SEC, and several have admitted privately that they would carry exposures to it.

Be that as it may, as things stand, the Group is in possession of what constitutes written advice that the SEC does not support proved reserves attribution on this basis in the GoM and, by inference, worldwide. The volume of exposed reserves is provisionally estimated to be 260 million barrels of oil-equivalent, although further clarification is being obtained via the 2003 year-end reserves reporting exercise.

8 December 2003

Confidential

**4.6 Production Sharing Contracts (PSCs)**

Proved reserves entitlement as disclosed at 31.12.2002 are, in principle, exposed by some 290 mln boe due to the use of Mid-PSV, rather than actual year-end price (Brent US\$ 28.66 per barrel), in their calculation (see also 3.2 above, in which offsets to this exposure are also explained).

**4.7 Other Exposures***Kashagan*

Reserves for the giant Kashagan field (Kazakhstan) of 380 mln bbl were booked in 2002 on the strength of Declaration of Commerciality (June 2002). A plan for the first phase of development (or 'Experimental Programme') was submitted in December 2002. However, the DOC has not yet been accepted by the authorities, pending resolution of some outstanding licence issues.

On further review in 2003, in the light of ever tightening guidance from the SEC (verbally), this booking can be deemed at risk on three counts:

- (i) it appears that the duration of the production phase of the PSC may have been misunderstood, causing 35 mln bbl of the booked reserves to fall outside the likely licence period,
- (ii) the proved area may be challengeable in terms of its extent given the rather sparse, currently available well coverage (the five wells drilled to date on Kashagan East are 7 – 12 km apart). With a planned average development well spacing of some 1.4 km, it is possible that only 90 km<sup>2</sup> out of the 400 km<sup>2</sup> target development area could qualify as being contained in the current proved area under the strictest application of the SEC rules, causing some 270 mln bbl to be exposed in this manner. The proved area was originally assigned on the basis that the (relatively) nearby, and geologically similar, Tengiz field provides compelling analogue evidence of the continuity of productive formation over the large distances concerned.
- (iii) Given the stalling of progress towards plan approval, the entire booking could be called into question with respect to the SEC's recent verbal guidance that no non-trivial government approvals should be outstanding in relation to proved reserves disclosures, as well as with reference to previous guidance that undue delay may call into question the right to book reserves.

One of the other partners in the field (Total) is believed to have booked a similar volume of proved reserves to Shell and this is understood to be the subject of ongoing challenge by the SEC on grounds (ii) and (iii) above. With the exercising in 2003 of pre-emption rights to BG's former share of the field, Shell would register an 80 mln bbl increase in proved reserves if the booking were retained at 31.12.2003.

8 December 2003

Confidential

*Miscellaneous*

Proved reserves in NAM's Waddenzee fields (25 MMboe) are potentially overstated on technical grounds and are exposed to a drilling and development moratorium by the Netherlands government until it can be demonstrated 'with certainty' (and publicly accepted) that there will be no damage to this ecologically sensitive area. This proof will be challenging to give and even more challenging to become accepted. However, public and government opinion are evolving and there are those that hold the view that these fields will, with time, become developed. The Group's exploration and pre-development costs for these fields were written down in 2000. These volumes do not meet the current Group reserves guidelines, nor the SEC definitions.

In Italy, the (ex-Enterprise) Tempa Rossa field Phase 1 development (proved reserves some 25 mln boe) was still poorly defined and faced significant commercial challenge at end 2002. The reserves were retained on condition that they would be debooked if FID had not been taken in 2003 and was not likely to be taken in 2004 either. Current assurance from the Asset Holder is that project sanction is 'imminent'.

In the (ex-Enterprise) Corrib gas field in Ireland (50 MMboe) there is the issue that the building permit for the onshore gas processing plant has been rejected by the authorities during 2003 without further right of appeal. Although an alternative site is now being proposed, this rejection means a serious set-back to Corrib field development. This is against the latest SEC requirements.

8 December 2003

Confidential

## 5. Status

## 5.1 Audit Summaries

*PDO*

1995: Proved Developed reserves appeared too high, while Proved undeveloped reserves were negative! Methodology suggested in previous audit report had not been followed. Audit trail showed expectation volumes only, not proved.

1999: Individual field proved volumes were too conservative. Proved developed did not properly reflect end-of-licence in 2012 and was too high, proved undeveloped reserves were too low, their sum (i.e. total reserves) seeming largely reasonable. Audit trail was good. Audit opinion: good.

2003: Proved developed reserves were reasonable. Proved total volumes had been kept unchanged in spite of recent downturns in production forecast to end-of-licence in 2012. In addition, a large share of proved undeveloped reserves was based on projects that did not meet the current test of maturity in the revised guidelines. Audit trail had deteriorated. Audit opinion: unsatisfactory.

*SPDC*

1993: Procedures to estimate proved developed reserves were in line with Group standards. Enhancements were seen in procedures for estimating total (probabilistic) reserves. Audit trail was good. Audit opinion: 'very satisfactory'.

1997: Difference in probabilistic procedures for proved developed reserves between East and West, both needed to be improved (too mechanical, no realistic low and high cases). Audit trail was poor, needing a repeat audit in 1999. Audit opinion: 'quite satisfactory'.

1999: Audit trail was (still) poor. Assumed long-term proved reserves forecast to end-of-licence in 2019 required a doubling of production rate. Proved reserves exposed if this should not materialize. Audit opinion: satisfactory.

2003: Audit addressed reserves estimation procedures only (not the resultant volumes, which were under review at the time). A significant portion of proved reserves was based on immature projects that did not fulfil present (tightened) Group guidelines. Status of 1.1.2003 proved reserves: unsatisfactory.

*Group Reserves Auditor Comment*

Both SPDC and PDO were affected by the tightening of project maturity requirements in the Group Guidelines that has occurred in recent years (see 2.2). In PDO this seems to have been caused by the extreme focus on short-term development opportunities ('keep the rigs busy to keep the oil rate up'), to the



8 December 2003

Confidential

detriment of defining longer term projects that would require more intensive study work (e.g. improved recovery and some EOR). Quite a number of these projects are also rather tenuous in nature (e.g. EOR) and not all of them may be realized.

As for SPDC, the reason for the lack of longer-term project definition is less clear. SPDC's proved undeveloped reserves over annual production ratio is quite high (some 22 years in 2002), which implies that many of the constituent projects would not need to be matured until much later in this decade. Although the oil is quite likely to be there, there simply was no need yet to address these projects in detail.

These problems would perhaps have been manageable if both companies had kept their house in order and kept a fully auditable link between individual field and project volumes and their booked corporate proved reserves and Business Plans. However, from 1999 onwards both companies were faced with oil production declining or remaining well below plan (field decline in PDO, externally imposed stagnation in SPDC). With the end-of-licence approaching (2012 in PDO, 2019 in SPDC) this meant that both companies should have reduced their proved reserves entitlements within licence accordingly<sup>5</sup>. The reality is that they didn't. Both companies chose to reduce their booked proved oil reserves by annual production only, meaning that quite unrealistic upturns in production were required to produce the stated volumes before the end-of-licence. Business Plan volumes (expectation) were changed more or less appropriately, but individual field estimates became neglected.

As for the reasons for this reluctance to face reality on the proved reserves front – it is possible that scorecards could have had something to do with it. There is also the issue of the significant reserves addition bonuses that both companies have received from the authorities over the years. However, these were in relation to full-life expectation reserves, not Group entitlement proved reserves. Some of these expectation volumes (particularly in PDO) should be (have been) classed as SFR anyway.

The result was that booked corporate proved reserves had started to live their own life and that the link with both CA/BP volumes and the individual fields' volumes was lost. It is possible that the decision to maintain the artificial proved reserves bookings was not taken very consciously, at least not at the highest levels. However, the lack of sound housekeeping (i.e. not linking corporate reserves to individual fields and projects) points to a neglect of proper

<sup>5</sup> EPS-P comment: had automatic licence extension not been assured for SPDC, such that reserves bookings would have continued to be constrained by expiry in 2019, the prize associated with licence extension would be some 200-300 mln bbl oil, as evaluated in 2003. For PDO, depending precisely how much of the current inventory would be debooked, the prize of licence extension beyond 2012 would be in the range 285 – 480 mln bbl.

8 December 2003

Confidential

procedures and this must have crept in during the last four years. In the case of PDO there is the further consideration that proved reserves never received much focus anyway - the government was hardly interested (this has now changed) and proved reserves were not needed for PDO or Group accounts.

The SPDC end-of-licence problem was resolved at a stroke when SPDC realised in 2002 that they had had the right to extend the licence in 2019 all along and that post-2019 volumes could therefore also be booked as Group entitlement reserves. This still left them with the problem of the large amount of ill-defined future project reserves.

The PDO end-of-licence issue has been addressed actively by PDO and it looks now likely that an agreement on an extension post-2012 will be reached early in 2004. However, due to the short-term development focus in recent years, PDO are still faced with a large volume of reserves for which they do not have a realistically defined plan. Even a number of projects that were seen as mature in 1999 are now seen as needing further work, in view of adverse field performance. In addition, PDO have allowed a serious slackening of their ARPR reserves process discipline to creep in over the last four years. This gave them considerably lower scores on the subjects of technical and commercial maturity and audit trails in the last audit.

Both companies are now bringing their house in order, i.e. they are aiming to achieve full alignment between individual fields, projects and plans in the course of 2004 (trying to do this earlier is probably not realistic because of the mammoth amount of work that is needed for a proper inventories and study). The unsatisfactory audit scores related therefore only to the status of the 1.1.2003 proved reserves (which is my brief as auditor), and much less to the efforts that have been spent since that time.

Finally, as a general remark, maintaining centrally enforced discipline in reserves estimation and reporting is extremely important. We have seen in SPDC and PDO what kind of damage a slackening in this respect can cause. It is possible that the two companies left the enforcement to too junior levels, much reducing its effectiveness. A similar slackening was seen in Expro during the end-2002 ex-Enterprise reserves audit. The audit report then commented on the adverse changes seen in their processes since the 'good' audit score from 2001.

8 December 2003

Confidential

## 5.2 Outstanding Work

SPDC: Phase 2 of the ongoing Resource Maturation study was completed on November 14 2003, resulting in the conclusions presented in this document. The next phase, which involves detailed planning of the studies effort required to address project maturity in the short term, is in progress. As mentioned previously, some 18 individual field studies, requiring 42 man-years of effort, are planned for 2004 in order to underpin some 310 mln bbl of exposed current proved reserves. Maturation of the remaining business plan exposure (814 mln bbl in total, including the 310 mln bbl to be matured in 2004) will proceed through 2005 and 2006. Only from that point onwards (and perhaps significantly later still) would it be feasible to assume that significant inroads could be made into the 720 mln bbl gap between the current base programme and actual proved reserves bookings at 31.12.2002.

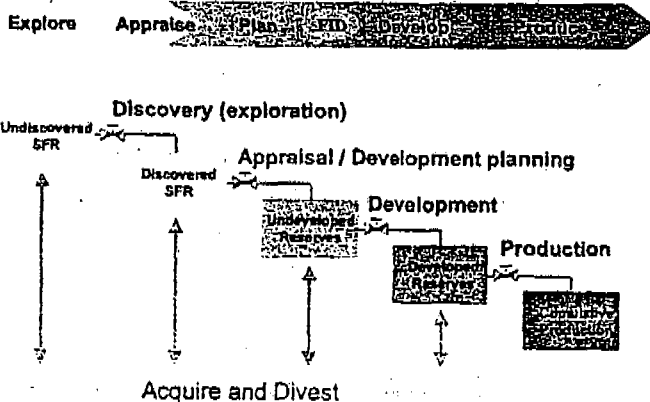
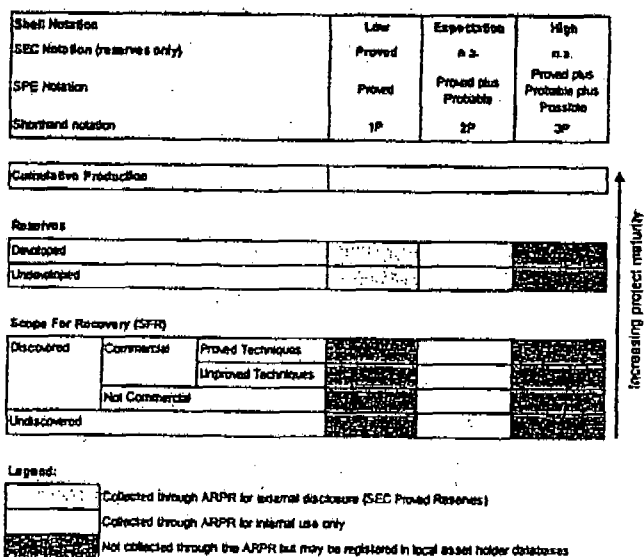
PDO: The STOIP and Reserves Review Team reported out in December 2003 and follow-up is now in planning by PDO. The existing studies plan should ensure that much of the currently identified exposure will be addressed by the end of 2008. However, this implies that, without a significant write-down of proved reserves now, substantial exposures would need to be carried over several years pending completion of this work.

8 December 2003

Confidential

## 6. Reclassification

This section summarizes how the affected volumes would be reclassified in the overall Group petroleum resource volume classification system, which is summarized below together with a representation of the "cascade" by which volumes mature from one category to the next:



At issue are the externally disclosed proved reserves. As indicated above, any debooking of proved reserves is likely to have a corresponding impact on expectation reserves, since the system essentially requires the same criteria of project maturity to apply to all reserves categories. For many of the exposures under discussion, the corresponding expectation reserves would be reclassified as Scope For Recovery (SFR) if proved reserves can no longer be justified.

EPS, EPF, EPT

40

Proved Reserves Dec 2003 Part 1 CMD doc

8 December 2003

Confidential

There are two exceptions to this: the LKH exposure would be addressed simply as a reduction of the applicable proved reserves volume in order to comply with the new SEC guidance. There would be no effect on expectation reserves. Similarly, for PSCs, addressing the year-end pricing exposure would simply affect the estimated volume of proved reserves entitlement: expectation reserves (for internal reporting purposes) would remain unchanged and would continue to be based on a Mid-PSV pricing assumption.

None of the reserves in question are at this stage considered likely to be deleted completely from the Group's total petroleum resource base (as would be the case, for example, if all hope of ever developing Gorgon would be abandoned). Thus, volumes might now be "debooked" would actually simply be reclassified to a less mature category in the overall system, only to be re-booked as reserves at a future date when the requisite project maturity has been attained. For most of the volumes under discussion, this "re-maturation" is unlikely to occur in the short-term.

In the following tables, the effect of debooking the two tranches of proved reserves in question (see section 4) is illustrated in terms of the impact on Reserves Replacement Ratio (RRR). The corresponding (NB: estimated) effect on expectation reserves is shown - these volumes would be posted as a positive reclassification to SFR. The estimated volumes that would re-mature to the proved reserves category in 2004 and 2005 are also shown, together with the corresponding effect on plan RRR.

For context, the total Group resource distribution at 31.12.2002 was as follows:

Total initially in place (discovered):	230,100	million boe
of which, estimated to be recoverable:	88,830	(ultimate recovery)
of which, remaining to be produced:	57,790	(31,040 produced to date)
of which, Expectation Reserves:	32,850	(24,940 discovered SFR)
of which, producible within licence:	24,280	(8,570 post-licence)
of which, Proved Reserves:	19,350	(4,390 probable reserves)
of which, developed:	8,870	(10,480 undeveloped)

In addition there is some 24,000 mln boe of Undiscovered SFR.

As well as the potential benefits to 2004 RRR of re-booking reserves (indicated in the table below), additional RRR benefit would be derived from including fuel and flare (some 300 mln boe, providing a ca. 20% once off boost to RRR). If PSC reporting were changed to year-end pricing, rather than Mid-PSV, a modest further gain would be derived from including tax-entitlement reserves in tax-paid PSCs. Furthermore, the application of year-end pricing to tax/royalty concessions would add in the order of 100 mln boe through the extension of economic field life (at current prices).

8 December 2003

Confidential

*Proved reserves which are likely to be considered as not compliant by the SEC*

mln boe	2003 Debooking		Proved Rebooking		Comment
	Proved	Exp'n	2004	2005	
Gorgon	-557	-785	0	430	1 train, unrisks
Nigeria #1	-720	-1400	0	0	To mature over the long term
Oman #1	-234	-240	480	0	To mature over the long term Rebooking: Licence extension.
LKH	-300	0	0	0	Re-bookings offset by LKH 'exposures' in assumed, planned bookings
PSCs	-291	0	50	50	Re-bookings at US\$24/bbl (2004) US\$20/bbl (2005) (actuals will depend on future price)
<b>TOTAL</b>	<b>-2102</b>	<b>-2430</b>	<b>530</b>	<b>480</b>	
<b>Effect on Total EP Reserves (at end-2002):</b>					
EP total	19348	32849			Excludes oil sands
EP adjusted	17246	30419			
<b>Effect on RRR:</b>					
LE / Plan	80%		66%	176%	Organic, ex-MI, ex-oil sands
Effect	-146%	-168%	37%	33%	
Adjusted	-66%		103%	209%	

*Proved reserves which might be considered as not compliant by the SEC*

mln boe	2003 Debooking		Proved Rebooking		Comment
	Proved	Exp'n	2004	2005	
Nigeria #2	-814	-1600	310	250	Base programme maturation
Oman #2	-150	0	-125	50	Rebooking - incremental to Oman #1 above - impact of higher initial debooking)
Kashagan	-380	-500	100	0	Re-booking limited to SEC proved area (+BG pre-emption)
Others	-200	-270	25	25	Notional project maturation
<b>Subtotal</b>	<b>-1544</b>	<b>-2370</b>	<b>310</b>	<b>325</b>	
<b>Firm</b>	<b>-2102</b>	<b>-2430</b>	<b>530</b>	<b>480</b>	From table above
<b>TOTAL</b>	<b>-3646</b>	<b>-4793</b>	<b>840</b>	<b>805</b>	
<b>Effect on Total EP Reserves (at end-2002):</b>					
EP total	19348	32849			Excludes oil sands
EP adjusted	15702	28056			
<b>Effect on RRR:</b>					
LE / Plan	80%		66%	176%	Organic, ex-MI, ex-oil sands
Effect	-253%	-333%	58%	56%	
Adjusted	-173%		124%	232%	

EPS, EPF, EPT

42

Proved Reserves Dec 2003 Part 1 CMD.doc

FOIA CONFIDENTIAL  
TREATMENT REQUESTED

V00010484

MOST CONFIDENTIAL

No. 2573

COMMITTEE OF MANAGING DIRECTORS  
MINUTES OF THE MEETING HELD IN THE HAGUE  
ON MONDAY, 8 AND TUESDAY, 9 DECEMBER 2003

Present:	P B Watts	Chairman
	J van der Veer	
	W van de Vijver (Items 6-21 inclusive only)	
	M A Brinded (Items 6-21 inclusive only)	
	J G Boynton	
	R J Routs (Items 6-21 inclusive only)	
	R M Fox	Secretary

1. MINUTES

The Minutes of CMD Meeting No. 2572 were approved, as amended.

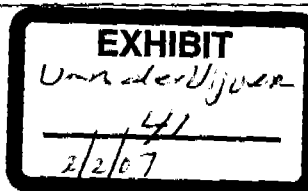
2. ANNUAL REPORTS

Jyoti Munsiff and Michiel Brandjes entered the meeting. Adrian Loader, Mary Jo Jacobi and Yvonne van Sprang joined by videoconference.

The Annual Report covers and size were agreed. On the Remuneration Reports the Committee commented that REMCO had a large number of comments on the drafts and that more work needed to be done on these pages. The intention was that for the Royal Dutch Remuneration Report, there would be a general statement regarding remuneration but on the specific figures only Royal Dutch Directors would be referred to. The same approach would apply to the Shell Transport and Trading Remuneration Report.

TT 000712

2573M



V00090869

FOIA Confidential  
Treatment Requested



**MOST CONFIDENTIAL**

It was agreed that the Chairman of REMCO, Mr Loudon, would sign the Remuneration Report for Shell Transport and Trading and for Royal Dutch.

Turning to the governance chapters, the Committee stated that for Shell Transport and Trading, the focus of the Report should be on the UK position including the Combined Code with reference to NL and the US. The same principle should apply in respect of the Royal Dutch Report with focus on Tabaksblat with reference to the position in the other 2 countries. In both cases the piece on the US would be common. As far as possible, the detailed matters relating to the Combined Code and Tabaksblat should be moved to the back of the Report and in NL it was possible to move some items to the Shell website. The same approach would be used in the Summary Reports.

It was agreed that the Chairman would sign the covering note for Shell Transport and Trading as Chairman of Shell Transport and Trading and Chairman of the Committee of Managing Directors. For Royal Dutch, Mr van der Veer would sign the covering note as President of Royal Dutch and Vice Chairman of the Committee of Managing Directors.

Turning to the Summary Reports, the Committee stated that there should be two versions of the message from the President of Royal Dutch and the Chairman of Shell Transport and Trading.

It was confirmed that the plain English society would be reviewing the wording of the documents. Further detailed comments were made on the draft pages and it was thought that the message from the Chief Financial Officer could be deleted to avoid potential overlap.

The matter would be referred back to the full meeting of the Committee on 13 January ensuring that all of the non-financial issues were already cleared by the business CEOs prior to the Committee meeting.

*Copy of Minute to: A Loader, J Munsiff, M Brandjes.*

### 3. INVESTMENT DECISION GUIDE

Tim Morrison and Beat Hess entered the meeting.

TT 000713

**MOST CONFIDENTIAL**

It was explained that the Group Capital Budget Manual needed updating and that the development of the draft Investment Decision Guide had been sponsored by the Financial Controller. The Committee raised the issue of whether, in relation to asset proposals, such as leases, there should be a maximum term of 15 years. In this context, the Committee commented that it needed to be made clear which items should be addressed in the Investment Decision Guide and which items would be dealt with in the CP Guidelines. It was agreed that this point would be taken back to the businesses for consideration. The question of the explicit support of the Director of Finance was discussed and the Committee stated how important it was for sufficient connection to be made with the Director of Finance and senior finance people in the decision making process. It was explained that the proposed change which required the input of the Finance Director concerned third party financing requirements exceeding \$500 mln. In that case, the Committee stated that it was important that there was consultation in good time with the Director of Finance in the preparation of any such proposal.

*Copy of Minute to: J Boynton, B Hess.*

#### 4. SARBANES-OXLEY ACT SECTION 404 COMPLIANCE

Tim Morrison explained that the Sarbanes-Oxley Act, Section 404 dealt with internal controls on financial reporting and that the Group Financial Controls Framework was to be reviewed in the light of this legislation. He added that the period for comment on the draft Regulations ended in November 2003 and Shell had made representations as had 183 other organisations. The main areas on which Shell commented were the very low materiality levels and the definition of materiality. Mr Morrison explained that the external auditors had been briefed and were aware of the work being done by Shell in this regard. He explained that it was necessary for those working on the Sarbanes-Oxley Section 404 project to have access to the business Chief Financial Officers. He added that assistance would be obtained from those in Shell Canada who were addressing this subject one year ahead. The Committee commented that it was very important that adequate commitment of resources was given to this project and Tim Morrison explained that a dedicated project manager from SEPSCO had been appointed to work full-time on the Financial Controls Handbook. He added that the scope of the work was not, however, fully clear because of the likelihood of change to the draft Regulations. More clarity on

TT 000714